division of energy resources
Minnesota Department of Commerce

85 7th Place East, Suite 500, St. Paul, MN 55101-2198
main: 651.296.4026
tty: 651.296.2860
fax: 651.297.7891
www.energy.mn.gov

March 12, 2012

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. G011/M-11-1084

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-PNG (MERC or the Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand entitlement for its Northern Natural Gas (Northern) Transmission System Purchased Gas Adjustment (PGA) effective November 1, 2011.

The filing was submitted on November 1, 2011. 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:

- **accept** the Company's peak day analysis; and
- **withhold approval of** the Company's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2011 until the Company provides in its *Reply Comments* clarification on its Petition as requested herein by the Department.

The Department will provide its recommendations after reviewing the MERC's *Reply Comments* and is available to answer any questions that the Commission may have.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G011/M-11-1084

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation-PNG (MERC-PNG, MERC or Company) filed a change in demand entitlement petition (*Petition)* on November 1, 2011 for its Northern Natural Gas Transmission (NNG or Northern) Purchased Gas Adjustment (PGA) system. In its *Petition*, MERC requests that the Minnesota Public Utilities Commission (Commission) accept the following changes in the Company's recovery of overall level of contracted capacity costs.

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	Proposed Changes: increase (decrease) (Dkt)[1]
TF 12 Base and Variable	529
TF5	226
TFX-12	227
TFX-5	633
Northwestern Energy (Ortonville)	910
NNG Zone GDD Call Option	11,235
LS Power Peaking	(25,951)
Sum of Increase	13,760
Sum of Decrease	(25,951)
Total Entitlement Net Change	**(12,191)**

MERC's 2010-2011 NNG design day requirements (overall needs of its customers on a design day) increased by 16,584 Mcf (or approximately 8.52 percent) from the previous year. The Company's proposal would decrease the design-day (winter) capacity by 12,191 Dekatherms

[1] Dekatherms (Dkt).

(Dkt). As discussed further below, it is appropriate for MERC to decrease its capacity even though the needs of its customers increased because MERC's previous reserve requirement was excessive at approximately 20 percent compared to the usual level of approximately 5 percent.

The Company describes the factors contributing to the change in demand entitlements as follows:[2]

- Demand Entitlement decreased primarily due to the elimination of the LS Power peaking service (25,951 Dkt);
- MERC-PNG replaced the LS Power peaking capability with a physical delivered Gas Daily call option (12,500 Dkt); and
- In April, 2011, NNG sold a line that served the City of Ortonville to Northwestern Energy. Since Ortonville is a MERC-PNG customer, this capacity (910 Dkt) is directly assigned to MERC-PNG.

The Company also proposed changes to non-capacity items in the November 2011 PGA compared to the October 2011 PGA as follows:

- increase in the amount of volumes associated with its TFX April and TFX October contracts;
- changes to its Bison/NBPL capacity as mentioned on page 15 of MERC's *Petition*;[3] and
- increase in the amount of volumes associated with its Firm Deferred Delivery (FDD) (storage) contracts.

The Department discusses the various effects on the Company's rates for different customer classes below, but notes that MERC-PNG's proposal would increase demand rates for General Service customers (which include residential customers) by \$0.1311 Dkt or approximately \$11.27[4] per year for customers using 86 Mcf. The Department discusses below why the proposals in this case would result in an increase in rates. The Company requested that the Commission allow recovery of the associated demand costs in its monthly PGA effective November 1, 2011.

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[2] MERC *Petition* pages 2-3

[3] MERC previously contracted for 50,000 Dkt/day capacity on the Bison Pipeline (Bison) which went into service on January 14, 2011. NNG, Bison and Northern Border Pipeline (NBPL) capacity is allocated between MERC-PNG and MERC-NMU based on a prorated share based on design day numbers. MERC-PNG's prorated percentage of NNG capacity is approximately 89.88% and MERC-NMU's prorated percentage is approximately 10.12%. Due to the proration, there was an increase of 1,615 Dkt in MERC-PNG winter capacity and a 351 Dkt increase in MERC-PNG's Bison and NBPL capacity. This arrangement allows MERC to access gas supplies in the Rocky Mountain region. This agreement, and the specifics associated with the Bison Project, are discussed in greater detail in Docket No. G007,011/M-08-698 as well as the Department's *Comments* in Docket Nos. G011/M-10-1168 and G007/M-10-1166.

[4] MERC Attachment 11, Page 1 of 2.

MERC included an attachment showing the rate impacts resulting from moving cost recovery of storage contracts from the demand cost recovery portion of the monthly PGA to the commodity portion.[5] On this attachment, MERC calculated that there would be a decrease in demand rates for the General Service Residential customer class when storage contract costs are included in the commodity portion of the PGA. Shifting storage costs to the commodity portion of the PGA would decrease the demand rates per year by $0.0531 per Dkt, resulting in an annual bill impact of approximately $4.56, for General Service Residential customers using 86 Mcf.

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

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

- the proposed overall demand entitlement level;
- the changes to non-capacity items;
- the design-day requirement;
- the reserve margin;
- the PGA cost recovery proposal; and
- the Department's inquiries regarding annual demand entitlement filings.

A. THE COMPANY'S DEMAND ENTITLEMENT LEVEL

1. Proposed Overall Demand Entitlement Level

As indicated in Department's Attachment 1, the Company has proposed to decrease its total entitlement level in Dkt as follows:

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
233,276	221,436	(12,191)	-5.222%

The Department analyzes below the proposed changes, the proposed design day requirement, and proposed reserve margin.

The Department understands there could be several reasonable explanations as to why the Company reduced its entitlements by 12,191 Dkt when its design day increased by 16,584 Dkt as follows:

[5] MERC Attachment 4, Pages 4 through 6 of 6, and Attachment 11 page 2 of 2.

- MERC decreased the level of entitlements to address the large positive reserve margin that was filed in the previous year's demand entitlement filing (Docket No. G011/M-10-1168);

- The potential impact of slow economic growth and lack of non-firm actual data in the design-day analysis. Please see the Department's *Response Comments* dated November 15, 2011, in Docket No. G011/M-10-1168, G007/M-10-1166 and G011/M-10-1167 wherein the following was stated on page 6:

> The Department and MERC have been working cooperatively on this issue in recent demand entitlement filings. The DOC agrees that having to estimate non-firm usage adds volatility to the design-day forecast and, as such, an additional level of forecasting error is introduced into the analyses. As noted by the Company in its *Reply Comments*, MERC received Commission approval in its 2008 rate case, Docket No. G007,011/GR-08-835, to install telemetry on all its non-firm customers (excluding farm taps). Once the telemetry is fully installed, and operational, the Company will be able to adequately track non-firm usage and more effectively forecast peak day use by firm customers. These data should be available in the coming years and, once these data is available, the issue of estimating non-firm usage will be resolved.
>
> The Company also provides additional discussion regarding the high reserve margins on its Northern, NMU, and Great Lakes PGA systems. In this discussion, MERC reiterates its concerns regarding slow economic growth and lack of actual non-firm data. The Company also discusses its responsibility in terms of balancing the overall MERC system. In particular, the Company states that it does not contract for firm capacity to meet non-firm usage, but it still has the responsibility to balance the entire system with respect to each interstate pipeline.

However, had MERC not terminated its LSP peaking provision with LS Power it would have had an increase in overall entitlements and a higher resulting reserve margin. In its *Petition,* MERC states that it replaced the LSP peaking capability with the NNG Zone GDD Option. This swap has the effect of significantly decreasing the capacity costs of the peaking service to approximately 10 percent of the previous LS Power costs. While MERC's proposal appears to be reasonable, in order to verify MERC's comparison in cost savings, the Department seeks clarification and requests MERC to provide the following additional information:

- Details on the Call Option contract such as the volumetric rates, the reservation rates, which party is responsible for capacity to ensure supply on a peak day and whether those transportation costs are included in the rate and costs shown in the Petition;

- A comparable cost/benefit analysis to the LS Power contract assuming that no winter capacity may be available on NNG; and

- A detailed explanation on the reliability aspect of the Company's choice to enter into an options contract for peaking service in the winter period and whether this is a short-term or a long-term contract.

The Department also seeks clarification of the amount of contract demand (CD) units shown in Attachment 5 of the Company's *Petition*. The Company's Attachment 5 indicates 95 CD units; however, in the Company's November 2011 PGA for MERC-PNG Northern it appears that no CD units are shown. In previous demand entitlement petitions, the Company has had zero CD units and typically the CD units have been excluded by the Company from both the total firm entitlement and design day. The Department requests that MERC provide clarification regarding these differences in its *Reply Comments*.

With regards to Contract No. 112486 with TFX-5 service, in previous demand entitlement filings in Docket Nos. G011/M-09-1284 and G011/M-10-1168 for MERC-PNG and in Docket Nos. G007/M-09-1282 and G007/M-10-1166 for MERC-NMU, the Company has had a total entitlement of 1,800 Dkt which has been allocated entirely to MERC-PNG or allocated to MERC-PNG and MERC-NMU in the amount of 1,605 and 195 Dkt respectively. However in the instant Petitions for both MERC-PNG and MERC-NMU, the resulting amount is (1,800 + 182) 1,982 Dkt respectively. Please see Department Attachment 3. As a result, the Department seeks clarification from the Company in its *Reply Comments* on whether it increased its capacity on this contract or if there was an error in the allocation between MERC-PNG and MERC-NMU.

The Department's conclusion regarding the Company's proposed recovery of overall demand costs will be provided after review of the Company's *Reply Comments* as discussed in further detail below.

2. Changes to Non-Capacity Items

In its Petition, MERC discussed the FDD storage contract changes as well as the Bison/NBPL changes that have the effect of increasing costs.

The DOC notes that it has advocated in several recent demand entitlement filings[6] that demand costs associated with storage costs should be recovered through the commodity portion of the PGA since all customers, not just firm customers, benefit from storage gas. The Commission has

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[6] Please see the Department's Comments in Docket Nos. G011/M-07-1405, G011/M-08-1328 and G011/M-09-1285.

not yet determined whether storage costs are more appropriately recovered through the commodity or through the demand portion of MERC's PGA.[7] The Department continues to prefer that MERC recover storage gas contract costs through the commodity portion of the PGA rather than the demand portion and recommends that the Commission determine that all customers, not just firm customers, should pay for costs of storage gas.

With regards to the storage contracts the Department observes the following in the Company's previous demand entitlement filings in Docket Nos. G011/M-07-1405, G011/M-08-1328, G011/M-09-1284 and G011/M-10-1168:

- The storage contract numbers change from 112490 to 118657; 113704 to 118215 to 119884 to 121292 to 122800; and

- The storage cycle volumes appear to be unrelated to the Maximum Storage Quantity (MSQ). For example, for storage contract number 118215 in Docket No. G011/M-08-1328, the storage cycle volumes are 36,221 in Attachment 4 but the MSQ in Attachment 5 is 18,110.

The Department seeks clarification from the Company as to why the storage contract numbers keep changing and for the Company to verify the storage cycle volumes, the MSQ numbers and the storage reservation numbers and all of the calculations that are shown in DOC Attachment 3 for both MERC-PNG and MERC-NMU.

It has been the DOC's position that the Bison/NBPL costs should be included in the commodity portion of the PGA, which is charged to firm and interruptible customers, rather than in the demand portion, which is charged only to firm customers, since all ratepayers benefit from supply diversification. Since the issue of Bison/NBPL costs has been thoroughly discussed in the previous demand entitlement filings in Docket Nos. G011/M-10-1168 and G007/M-10-1166 as well as the specifics associated with the Bison Project which are discussed in greater detail in Docket No. G007,011/M-08-698, the DOC does not provide additional discussion here, but maintains its recommendations that the Bison/NBPL costs should be included in the commodity portion of the PGA.

3. Design-Day Requirement

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. MERC 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

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[7] The Department notes that the Commission's February 28, 2012 Order in Docket No. G007/M-11-1078 allows CenterPoint Energy to allocate 34.31 percent of storage costs to the commodity cost portion of CenterPoint Energy's PGA.

determinants in its efforts to produce the most robust design-day estimates possible; however, the Department notes that some of these additional data were taken from a proprietary source as also discussed in the Department's January 3rd and 10th, 2012 *Comments* in Docket Nos. G011/M-11-1082 and G011/M-11-1083 respectively. When a utility uses proprietary data in its analysis, the Department cannot fully verify that the results of the analysis are correct.

3. *Reserve Margin*

As indicated in the Department's Attachment 1, the reserve margin is as follows:

Total Entitlement (Dkt)	**Design-day Estimate (Dkt)**	**Difference (Dkt)**	**Reserve Margin[8] %**	**% Change From Previous Year**
221,436	211,182	10,254	4.86%	-15.2%

The proposed reserve margin of 4.86 percent represents a significant decrease over last year's high reserve margin. Because the new level is approximately 5 percent, based on this information and the DOC's analysis of the Company's design-day analysis, the DOC concludes that the reserve margin appears to be reasonable at this time.

B. 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. Overall, the Department notes that, even though MERC proposes to decrease the level of demand volumes, there would be an increase in rates. The primary reason for the increase is due to the Bison/NBPL contract as follows:

- There is a slight increase in the re-allocation amount between MERC-PNG and MERC-NMU (44, 589 in Oct 2011 change to 44, 940 to MERC-PNG in Nov 2011 PGAs);
- The number of months that the rates for this capacity are charged to customers goes up from 9.6 months (Oct 2011 PGA) to 12 months;
- Both of the above facts result in an approximately $2,750,000 increase in demand costs attributable to Bison/NBPL capacity; and
- The Bison capacity is the most expensive, although reasonable, as discussed in previous demand entitlement filings.

In its Petition, the Company compared its October 2011 PGA to its November 2011 PGA as a means of highlighting its changes in demand costs (MERC Attachment 4, Page 1 of 4). The Company's demand entitlement proposal would result in the following annual demand cost impacts:

[8] As shown on Department Attachment 1, the Company's average reserve margin since 2000-2001 has been 7.54%.

- Annual bill increase of $11.27 related to demand costs, or approximately 8.14 percent, for the average General Service customer consuming 86 Dkt annually;[9]
- Annual bill increase of $2.55 related to demand costs, or approximately 0.95 percent, for the average Small Volume Firm customer consuming 4,800 Dkt annually; and
- Annual bill increase of $7.64 related to demand costs, or approximately 0.95 percent, for the average Small Volume Firm customer consuming 14,841 Dkt annually.

Table 1 below shows MERC-PNG's calculation of the changes in the average annual total cost of gas in the November PGA compared with the October PGA in two scenarios: Column A - storage costs included in the demand portion of the PGA, and Column B - storage costs included in commodity portion. As mentioned before, it has been the Department's position that storage costs should be included in the commodity portion of the PGA rather than the demand portion because all ratepayers benefit from storage gas. The Department continues to recommend that MERC include storage gas contract costs in the commodity portion of the PGA rather than the demand portion.

Table 1: Changes in Average Annual Total Cost of Gas[10]– Storage Cost Treatment

Customer Class	(A) Storage Costs Included in Demand Charge[11]	(B) Storage Costs Included in Commodity Charge[12]
General Service Residential 86 Dkt Annual Use	$31.17	$29.22
Small Volume Interruptible 4,371 Dkt Annual Use	$1,101.41	$1,717.38
Large Volume Interruptible 11,202 Dkt Annual Use	$2,592.04	$4,401.29
Small Volume Firm/Joint 4,800 Dkt Annual Use	$1,113.22	$2,041.25
Large Volume Firm/Joint 14,841 Dkt Annual Use	$3,441.71	$6,297.03

Table 1 above reflects calculations shown in attachments to MERC's *Petition*. However, the Department notes that, while the Company claims that the $/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 and FERC Docket RP11-1781, the $3.9932 rate (October 2011 commodity cost for General Service Residential customers) does include the refunds;

[9] The bill impacts recommended by the Company do not take into account a shift in storage costs from the demand portion of the monthly PGA to the commodity portion of the monthly PGA.
[10] Includes Commodity Cost of Gas (WACOG), Demand Cost and Commodity Margin.
[11] MERC Attachment 4, Page 1 of 6, and Attachment 11, Page 1 of 2
[12] MERC Attachment 4, Page 4 of 6, and Attachment 11, Page 2 of 2

C. DEPARTMENT INQUIRIES REGARDING ANNUAL DEMAND ENTITLEMENT FILINGS

The Department issued discovery to each regulated Minnesota gas utility requesting input regarding the annual demand entitlement filing timeline and the reasonableness of acquiring capacity contracts for the upcoming heating season in excess of the amount estimated by the design-day analysis. The Department discussed this matter in more detail in its *Comments* in MERC's companion docket nos. G011/M-11-1082 and G011/M-11-1083 respectively and will not repeat the same discussion here.

1. Timeline

Based on the discovery responses, there is universal agreement that the demand entitlement filings could be filed in the summer rather than in the fall. In particular, the utilities stated that they could make their filings either on July 1st or August 1st of each year. In its *Reply Comments* dated January 13, 2012 in Docket 11-1083, MERC states that it will comply with the Department's recommended initial filing date of August 1 and that MERC is willing to further discuss with the Department the proposed changes in procedure to the demand entitlement filings. The Department appreciates MERC's response.

2. Excess Capacity

Regarding excess capacity, MERC states the following in its *Reply Comments* dated January 13, 2012 in Docket 11-1083:

> Regarding additional and reserve capacity, IPL pointed out that it is important to hold approximately five percent reserve margin to ensure reliability for customers because of forecasting variances. MERC does not have daily reads for all customer classes and agrees that a five percent reserve margin is necessary and reasonable.
>
> Regarding phased in capacity and excess capacity costs, MERC utilizes the capacity release market to address excess capacity. IPL reports that it primarily relies on temporary non-recallable capacity releases to alleviate the issue of excess capacity. MERC could explore the use of non-recallable capacity releases, but it would only do so for volumes in excess of the positive five percent reserves.

The Department suggests that, if MERC wants to explore the use of non-recallable capacity releases above an adequate reserve margin calculated for the upcoming heating season, then MERC should provide information substantiating that these additional volumes will not be necessary in the current as well as future heating seasons or up until the time when such capacity is needed for design day and peak day conditions to reliably serve its firm customers.

III. THE DEPARTMENT'S RECOMMENDATIONS

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

- accept the Company's peak-day analysis;
- withhold approval of the Company's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2011 until the Company provides in its *Reply Comments* clarification on its Petition as requested herein for the following items:
    - clarification and additional information on the NNG Zone GDD Option;
    - the amount of CD units and whether they are included in the peak-day and design day analysis;
    - whether MERC increased its capacity on contract 112486 (TFX-5) or if there was an error in the allocation between MERC-PNG and MERC-NMU; and
    - explanation for the storage contract number changes and verification of the storage cycle volumes, the MSQ numbers and the storage reservation numbers and all of the calculations that are shown in DOC Attachment 3 for both MERC-PNG and MERC-NMU.

The Department will provide its conclusion regarding the Company's proposed recovery of overall demand costs and the proposed level of entitlements after reviewing the Company's *Reply Comments*.

/jl

DOC Attachment 1
Allocation and Direct Assignment
of NNG Demand Entitlements
As Proposed by MERC

	M-04-1766 Peoples Mn GS	**M-05-1728 Peoples Mn GS**	Proposed Change	**M-06-1536 Peoples Mn GS**	Proposed Change	**M-07-1405 MERC Mn GS**	Proposed Change
Design Day (excludes CD units)	207,834	200,421		200,484		202,263	
Customer Requirements moving to Transportation 2005-6		400		0		0	
Adjusted Design Day		200,021	(7,813)	200,484	463	202,263	1,779
Total Design Day Capacity (includes non-recallable capacity)	219,984	210,127	(9,857)	227,526	17,399	226,785	(741)
Less: NGPL	0	0	0	0	0	0	0
Less: Windom	2,500	2,500	0	2,500	0	2,500	0
Less: LS Power	6,120	6,120	0	29,100	22,980	26,323	(2,777)
Less: Northwestern Energy (Ortonville)		0	0	0	0	0	0
Less: Chisago Delivery to Viking	0	0	0	7,000	7,000	7,000	0
Less: TF12B	5,927	5,927	0	0	(5,927)	0	0
Less: TF5	2,073	2,073	0	0	(2,073)	0	0
Less: TFX(5)	0	0	0	0	0	0	0
Less: Contract Demand Units	0	0	0	0	0	0	0
Total Design Day Capacity (excluding direct assignments)	236,604	193,507	(43,097)	188,926	(4,581)	190,962	2,036
Allocated Entitlements in PGA							
TF12B	69,105	68,765	(341)	42,170	(26,595)	43,858	1,688
TF12V	0	0	0	34,070	34,070	15,946	(18,124)
TF5	93,690	84,713	(8,977)	36,772	(47,941)	29,619	(7,153)
TFX12 (112486)	0	11,318	11,318	9,724	(1,594)	9,724	0
TFX(5) (112486)	0	0	(23,052)	65,117	65,117	46,558	(18,559)
TFX(5) (112561)	0	0	0	6,000	6,000	6,000	0
TFX(5) (112486)	23,052	22,598	(453)	2,073	(20,525)	3,996	1,923
TFX(5) (12-V)	0	6,113	6,113	0	(6,113)	0	0
TFX12 (111866)	0	0	0	0	0	414	414
TFX12 (111866)	0	0	0	0	0	8,271	8,271
TFX5 (111866)	0	0	0	0	0	33,576	33,576
Total Allocated Entitlements in PGA	203,364	193,507	(9,857)	195,926	2,419	197,962	2,036
Direct Assigned Entitlements in PGA							
NGPL	0	0	0	0	0	0	0
Windom	2,500	2,500	0	2,500	0	2,500	0
LS Power	6,120	6,120	0	29,100	22,980	26,323	(2,777)
Northwestern Energy (Ortonville)	0	0	0	0	0	0	0
NNG Zone GDD Call Option	0	0	0	0	0	0	0
TFX(5)	5,927	5,927	0	0	(5,927)	0	0
TFX(7)	2,073	2,073	0	0	(2,073)	0	0
TFX(5)	0	0	0	0	0	0	0
TFX7 chg to TFX12 (111866)*	0	0	0	0	0	0	0
Total Direct Assignments	16,620	16,620	0	31,600	14,980	28,823	(2,777)
Total Capacity before Peak Shaving	219,984	210,127	(9,857)	227,526	17,399	226,785	(741)
LP Peak Shaving	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	219,984	210,127	(9,857)	227,526	17,399	226,785	(741)
Total Annual Transportation	75,032	68,765	(6,268)	76,240	7,475	59,804	(16,436)
Total Seasonal Transportation	136,332	115,497	(20,834)	38,845	(76,652)	67,191	28,346
Total Percent Seasonal	62.0%	55.0%	-7.0%	17.1%	-37.9%	29.6%	12.6%
LS Power as % of Total DD Capacity	2.8%	2.9%	0.1%	12.8%	9.9%	11.6%	-1.2%
Reserve Margin	5.85%	5.05%	-0.8%	13.49%	8.4%	12.12%	-1.4%
Direct Assigned Demand Not in PGA							
TF-12-B Contract Demand	0	0	0	0	0	0	0
Total Design Day Capacity w/ contract demand	219,984	210,127	(9,857)	227,526	17,399	226,785	(741)
Other Entitlements not included in Peak Day Deliverability							
Field TF (TFF) (NMU direct assigned)	0	0	0	0	0	0	0
TFX Offpeak Old Oct. (60,000)	20,272	20,227	(45)	0	(20,227)	0	0
TFX Offpeak Old Oct. (35,000)	11,825	11,799	(26)	0	(11,799)	0	0
TFX Offpeak New Oct. (14,600)	4,933	4,922	(11)	0	(4,922)	0	0
TFX Offpeak New Apr. (39,600)	13,380	13,350	(30)	0	(13,350)	0	0
TFX Oct	0	0	0	2,000	2,000	2,000	0
TFX Apr	0	0	0	0	0	2,000	2,000
TFX7 chg to TFX12 (111866)*	0	0	0	0	0	10,837	10,837
TFX Apr-Oct	2,861	2,855	(6)	0	(2,855)	0	0
TFX May-Sept	4,933	4,922	(11)	0	(4,922)	0	0
FDD Storage reservation (112490)	46,935	46,830	(105)	69,094	22,264	68,309	(785)
FDD Storage capacity MSQ **1/**	2,706,028	2,699,984	(6,044)	3,983,639	1,283,655	3,938,382	(45,257)
FDD Storage reservation (113704)	0	0	0	0	0	4,712	4,712
FDD Storage capacity MSQ 2/	0	0	0	0	0	271,655	271,655
FDD Storage reservation (118215)	0	0	0	0	0	0	0
FDD Storage capacity MSQ 3/	0	0	0	0	0	0	0
FDD Storage reservation (118657)	0	0	0	0	0	0	0
FDD Storage capacity MSQ 4/	0	0	0	0	0	0	0
ANR Capacity	0	0	0	0	0	0	0
Nexen PSO	86,157	85,964	(192)	0	(85,964)	0	0
Tenaska PSO New	168,935	168,558	(377)	172,193	3,635	170,237	(1,956)
NGPL	1,202,218	1,199,532	(2,685)	0	(1,199,532)	0	0
SMS	18,245	18,204	(41)	20,773	2,569	20,537	(236)
SBA	2,399,879	0	(2,399,879)	0	0	0	0
Upstream Demand per Mo		0	0	0	0	0	0
Bison/NBPL (FT0003 & T8673F)		0	0	0	0	0	0
AECO Storage		0	0	0	0	0	0
1/ Cycled Volumes =		787,676	787,676	796,728	9,052	787,676	(9,052)
2/ Cycled Volumes =		0	0	0	0	54,331	54,331
3/ Cycled Volumes =		0	0	0	0	0	0
4/ Cycled Volumes =		0	0	0	0	0	0

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

DOC Attachment 1
Allocation and Direct Assignment
of NNG Demand Entitlements
As Proposed by MERC

	M-08-1328 MERC Mn GS	Proposed Change	M-09-1284 MERC Mn GS	Proposed Change	M-10-1168 MERC Mn GS	Proposed Change	M-11-1084 MERC Mn GS
Design Day (excludes CD units)	**225,397**		**203,360**		**194,598**		**211,182**
Customer Requirements moving to Transportation 2005-6	**0**		**0**		**0**		**0**
Adjusted Design Day	**225,397**	23,134	**203,360**	(22,037)	**194,598**	(8,762)	**211,182**
Total Design Day Capacity (includes non-recallable capacity)	**226,785**	0	**231,064**	4,279	**233,627**	2,563	**221,436**
Less: NGPL	**0**	0	**0**	0	**0**	0	**0**
Less: Windom	**2,500**	0	**2,500**	0	**2,500**	0	**2,500**
Less: LS Power	**26,323**	0	**26,375**	52	**25,951**	(424)	**0**
Less: Northwestern Energy (Ortonville)	**0**	0	**0**	0	**0**	0	**910**
Less: Chisago Delivery to Viking	**7,000**	0	**7,000**	0	**0**	(7,000)	**0**
Less: TF12B	**0**	0	**0**	0	**0**	0	**0**
Less: TF5	**0**	0	**0**	0	**0**	0	**0**
Less: TFX(5)	**0**	0	**0**	0	**0**	0	**0**
Less: Contract Demand Units	**0**	0	**0**	0	**0**	0	**0**
Total Design Day Capacity (excluding direct assignments)	**190,962**	0	**195,189**	4,227	**205,176**	9,987	**218,026**
Allocated Entitlements in PGA							
TF12B	**29,906**	(13,952)	**35,221**	5,315	**34,875**	(346)	**42,396**
TF12V	**32,690**	16,744	**24,583**	(8,107)	**32,290**	7,707	**25,298**
TF5	**26,827**	(2,792)	**29,619**	2,792	**28,785**	(834)	**29,011**
TFX12 (112486)	**9,724**	0	**9,724**	0	**9,651**	(73)	**9,727**
TFX(5) (112486)	**46,558**	0	**48,754**	2,196	**51,163**	2,409	**51,383**
TFX(5) (112561)	**6,000**	0	**6,000**	0	**5,351**	(649)	**5,393**
TFX(5) (112486)	**3,996**	0	**1,800**	(2,196)	**1,605**	(195)	**1,800**
TFX(5) (12-V)	**0**	0	**0**	0	**0**	0	**0**
TFX12 (111866)	**414**	0	**414**	0	**1,144**	730	**1,153**
TFX12 (111866)	**8,271**	0	**9,140**	869	**7,376**	(1,764)	**7,434**
TFX5 (111866)	**33,576**	0	**25,013**	(8,563)	**22,306**	(2,707)	**22,482**
Total Allocated Entitlements in PGA	**197,962**	0	**190,268**	(7,694)	**194,546**	4,278	**196,077**
Direct Assigned Entitlements in PGA							
NGPL	**0**	0	**0**	0	**0**	0	**0**
Windom	**2,500**	0	**2,500**	0	**2,500**	0	**2,500**
LS Power	**26,323**	0	**26,375**	52	**25,951**	(424)	**0**
Northwestern Energy (Ortonville)	**0**	0	**0**	0	**0**	0	**910**
NNG Zone GDD Call Option	**0**	0	**0**	0	**0**	0	**11,235**
TFX(5)	**0**	0	**0**	0	**0**	0	**0**
TFX(7)	**0**	0	**0**	0	**0**	0	**0**
TFX(5)	**0**	0	**0**	0	**0**	0	**0**
TFX7 chg to TFX12 (111866)*	**0**	0	**11,921**	11,921	**10,631**	(1,290)	**10,715**
Total Direct Assignments	**28,823**	0	**40,796**	11,973	**39,082**	(1,714)	**25,360**
Total Capacity before Peak Shaving	**226,785**	0	**231,064**	4,279	**233,628**	2,564	**221,437**
LP Peak Shaving	**0**	0	**0**	0	**0**	0	**0**
Total Design Day Capacity w/o Contract Demand	**226,785**	0	**231,064**	4,279	**233,628**	2,564	**221,437**
Total Annual Transportation	**62,596**	2,792	**59,804**	(2,792)	**67,165**	7,361	**67,694**
Total Seasonal Transportation	**64,399**	(2,792)	**56,432**	(7,967)	**52,696**	(3,736)	**53,293**
Total Percent Seasonal	**28.4%**	-1.2%	**24.4%**	-4.0%	**22.6%**	-1.9%	**24.1%**
LS Power as % of Total DD Capacity	**11.6%**	0.0%	**11.4%**	-0.2%	**11.1%**	-0.3%	**0.0%**
Reserve Margin	**0.62%**	-11.5%	**13.62%**	13.0%	**20.06%**	6.4%	**4.86%**
Direct Assigned Demand Not in PGA							
TF-12-B Contract Demand	**0**	0	**0**	0	**0**	0	**0**
Total Design Day Capacity w/ contract demand	**226,785**	0	**231,064**	4,279	**233,628**	2,564	**221,437**
Other Entitlements not included in Peak Day Deliverability							
Field TF (TFF) (NMU direct assigned)	**0**	0	**0**	0	**0**	0	**0**
TFX Offpeak Old Oct. (60,000)	**0**	0	**0**	0	**0**	0	**0**
TFX Offpeak Old Oct. (35,000)	**0**	0	**0**	0	**0**	0	**0**
TFX Offpeak New Oct. (14,600)	**0**	0	**0**	0	**0**	0	**0**
TFX Offpeak New Apr. (39,600)	**0**	0	**0**	0	**0**	0	**0**
TFX Oct	**2,000**	0	**2,000**	0	**1,784**	(216)	**1,798**
TFX Apr	**2,000**	0	**2,000**	0	**1,784**	(216)	**1,798**
TFX7 chg to TFX12 (111866)*	**10,837**	0	**0**	(10,837)	**0**	0	**0**
TFX Apr-Oct	**0**	0	**0**	0	**0**	0	**0**
TFX May-Sept	**0**	0	**0**	0	**0**	0	**0**
FDD Storage reservation (112490)	**68,309**	0	**66,871**	(1,438)	**67,273**	402	**67,803**
FDD Storage capacity MSQ **1/**	**3,938,382**	0	**3,855,372**	(83,010)	**3,878,642**	23,270	**3,909,172**
FDD Storage reservation (113704)	**0**	(4,712)	**0**	0	**0**	0	**0**
FDD Storage capacity MSQ 2/	**0**	(271,655)	**0**	0	**0**	0	**0**
FDD Storage reservation (118215)	**3,141**	3,141	**4,722**	1,581	**6,187**	1,465	**6,236**
FDD Storage capacity MSQ 3/	**181,100**	181,100	**272,177**	91,077	**356,700**	84,523	**359,510**
FDD Storage reservation (118657)	**5,026**	5,026	**5,035**	9	**4,949**	(86)	**4,988**
FDD Storage capacity MSQ 4/	**289,765**	289,765	**290,335**	570	**285,370**	(4,965)	**287,615**
ANR Capacity	**0**	0	**0**	0	**0**	0	**0**
Nexen PSO	**0**	0	**0**	0	**0**	0	**0**
Tenaska PSO New	**0**	(170,237)	**0**	0	**0**	0	**0**
NGPL	**0**	0	**0**	0	**0**	0	**0**
SMS	**20,537**	0	**20,577**	40	**20,226**	(351)	**20,385**
SBA	**0**	0	**0**	0	**0**	0	**0**
Upstream Demand per Mo	**0**	0	**0**	0	**0**	0	**0**
Bison/NBPL (FT0003 & T8673F)	**0**	0	**0**	0	**44,589**	44,589	**44,940**
AECO Storage	**0**	0	**0**	0	**0**	0	**0**
1/ Cycled Volumes =	**787,676**	0	**771,074**	(16,602)	**775,728**	4,654	**781,834**
2/ Cycled Volumes =	**0**	(54,331)	**0**	0	**0**	0	**0**
3/ Cycled Volumes =	**36,221**	36,221	**54,437**	18,216	**71,342**	16,905	**71,904**
4/ Cycled Volumes =	**57,953**	57,953	**58,067**	114	**57,074**	(993)	**57,523**

DOC Attachment 1
Allocation and Direct Assignment
of NNG Demand Entitlements
As Proposed by MERC

	Proposed Change
Design Day (excludes CD units)	
Customer Requirements moving to Transportation 2005-6	
Adjusted Design Day	16,584
Total Design Day Capacity (includes non-recallable capacity)	(12,191)
Less: NGPL	0
Less: Windom	0
Less: LS Power	(25,951)
Less: Northwestern Energy (Ortonville)	910
Less: Chisago Delivery to Viking	0
Less: TF12B	0
Less: TF5	0
Less: TFX(5)	0
Less: Contract Demand Units	0
Total Design Day Capacity (excluding direct assignments)	12,850
Allocated Entitlements in PGA	
TF12B	7,521
TF12V	(6,992)
TF5	226
TFX12 (112486)	76
TFX(5) (112486)	220
TFX(5) (112561)	42
TFX(5) (112486)	195
TFX(5) (12-V)	0
TFX12 (111866)	9
TFX12 (111866)	58
TFX5 (111866)	176
Total Allocated Entitlements in PGA	1,531
Direct Assigned Entitlements in PGA	
NGPL	0
Windom	0
LS Power	(25,951)
Northwestern Energy (Ortonville)	910
NNG Zone GDD Call Option	11,235
TFX(5)	0
TFX(7)	0
TFX(5)	0
TFX7 chg to TFX12 (111866)*	84
Total Direct Assignments	(13,722)
Total Capacity before Peak Shaving	(12,191)
LP Peak Shaving	0
Total Design Day Capacity w/o Contract Demand	(12,191)
Total Annual Transportation	529
Total Seasonal Transportation	597
Total Percent Seasonal	1.5%
LS Power as % of Total DD Capacity	-11.1%
Reserve Margin	-15.2%
Direct Assigned Demand Not in PGA	
TF-12-B Contract Demand	0
Total Design Day Capacity w/ contract demand	(12,191)
Other Entitlements not included in Peak Day Deliverability	
Field TF (TFF) (NMU direct assigned)	0
TFX Offpeak Old Oct. (60,000)	0
TFX Offpeak Old Oct. (35,000)	0
TFX Offpeak New Oct. (14,600)	0
TFX Offpeak New Apr. (39,600)	0
TFX Oct	14
TFX Apr	14
TFX7 chg to TFX12 (111866)*	0
TFX Apr-Oct	0
TFX May-Sept	0
FDD Storage reservation (112490)	530
FDD Storage capacity MSQ **1/**	30,530
FDD Storage reservation (113704)	0
FDD Storage capacity MSQ 2/	0
FDD Storage reservation (118215)	49
FDD Storage capacity MSQ 3/	2,810
FDD Storage reservation (118657)	39
FDD Storage capacity MSQ 4/	2,245
ANR Capacity	0
Nexen PSO	0
Tenaska PSO New	0
NGPL	0
SMS	159
SBA	0
Upstream Demand per Mo	0
Bison/NBPL (FT0003 & T8673F)	351
AECO Storage	0
1/ Cycled Volumes =	6,106
2/ Cycled Volumes =	0
3/ Cycled Volumes =	562
4/ Cycled Volumes =	449

	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)
2011-2012	157,442	-856	-0.54%	211,182	16,584	8.52%	221,436	-12,191	-5.22%	4.86%
2010-2011	158,298	628	0.40%	194,598	(8,762)	-4.31%	233,627	2,563	1.11%	20.06%
2009-2010	157,670	697	0.44%	203,360	(22,037)	-9.78%	231,064	4,279	1.89%	13.62%
2008-2009	156,973	1,063	0.68%	225,397	23,134	11.44%	226,785	0	0.00%	0.62%
2007-2008	155,910	6,861	4.60%	202,263	1,779	0.89%	226,785	(741)	-0.33%	12.12%
2006-2007	149,049	741	0.50%	200,484	463	0.23%	227,526	17,399	8.28%	13.49%
2005-2006	148,308	4,412	3.07%	200,021	(7,813)	-3.76%	210,127	(9,857)	-4.48%	5.05%
2004-2005	143,896	3,191	2.27%	207,834	9,313	4.69%	219,984	13,844	6.72%	5.85%
2003-2004	140,705	3,957	2.89%	198,521	3,042	1.56%	206,140	(5,537)	-2.62%	3.84%
2002-2003	136,748	4,156	3.13%	195,479	(1,007)	-0.51%	211,677	13,282	6.69%	8.29%
2001-2002	132,592	2,844	2.19%	196,486	1,522	0.78%	198,395	0	0.00%	0.97%
2000-2001	129,748	3,446	2.73%	194,964	5,146	2.71%	198,395	7,195	3.76%	1.76%
1999-2000	126,302	3,619	2.95%	189,818	5,336	2.89%	191,200	3,425	1.82%	0.73%
1998-1999	122,683	3,102	2.59%	184,482	4,634	2.58%	187,775	6,709	3.71%	1.78%
1997-1998	119,581	700	0.59%	179,848	10,952	6.48%	181,066	27,179	17.66%	0.68%
1996-1997	118,881	2,942	2.54%	168,896	19,064	12.72%	153,887	12,792	9.07%	-8.89%
1995-1996	115,939	2,061	1.81%	149,832	(12,357)	-7.62%	141,095	0	0.00%	-5.83%
1994-1995	113,878	3,886	3.53%	162,189	5,252	3.35%	141,095	0	0.00%	-13.01%
1993-1994	109,992	2,588	2.41%	156,937	3,693	2.41%	141,095	(3,685)	-2.55%	-10.09%
1992-1993	107,404	2,705	2.58%	153,244	3,859	2.58%	144,780	0	0.00%	-5.52%
1991-1992	104,699	731	0.70%	149,385	1,043	0.70%	144,780	907	0.63%	-3.08%
1990-1991	103,968			148,342			143,873			
Average:			2.00%			1.84%			2.20%	2.52%

	Firm Peak Day Sendout								
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
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)*******	**Peak Day Sendout per DD Customer (12)/(1)**
2011-2012	unknown	unknown			0.0651	1.3413	1.4065	unknown	unknown
2010-2011	157,442	163,142	11,205	7.37%	0.2466	1.2293	1.4759	1.0362	0.9946
2009-2010	158,298	151,937	(24,288)	-13.78%	0.1757	1.2898	1.4655	0.9598	1.0040
2008-2009	157,670	176,225	(6,584)	-3.60%	0.0088	1.4359	1.4447	1.1177	1.0044
2007-2008	156,973	182,809	21,626	13.42%	0.1573	1.2973	1.4546	1.1646	1.0068
2006-2007	155,910	161,183	(22,248)	-12.13%	0.1814	1.3451	1.5265	1.0338	1.0814
2005-2006	148,308	183,431	24,083	15.11%	0.0681	1.3487	1.4168	1.2368	1.2368
2004-2005	148,242	159,348	(7,019)	-4.22%	0.0844	1.4443	1.5288	1.0749	1.1074
2003-2004	143,830	166,367	7,044	4.42%	0.0541	1.4109	1.4651	1.1567	1.1824
2002-2003	140,705	159,323	17,247	12.14%	0.1185	1.4295	1.5479	1.1323	1.1651
2001-2002	137,259	142,076	(22,028)	-13.42%	0.0144	1.4819	1.4963	1.0351	1.0715
2000-2001	132,247	164,104	21,769	15.29%	0.0264	1.5026	1.5291	1.2409	1.2648
1999-2000	131,538	142,335	(13,628)	-8.74%	0.0109	1.5029	1.5138	1.0821	1.1269
1998-1999	127,014	155,963	7,292	4.90%	0.0268	1.5037	1.5306	1.2279	1.2713
1997-1998 *	122,683	148,671	(13,962)	-8.58%	0.0102	1.5040	1.5142	1.2118	1.2433
1996-1997	119,581	162,633	(13,299)	-7.56%	-0.1263	1.4207	1.2945	1.3600	1.3680
1995-1996 **	118,881	175,932	39,122	28.60%	-0.0754	1.2923	1.2170	1.4799	**1.5175**
1994-1995	116,296	136,810	(27,074)	-16.52%	-0.1852	1.4242	1.2390	1.1764	1.2014
1993-1994	unknown	163,884	35,896	28.05%	-0.1440	1.4268	1.2828	**1.4900**	1.4900
1992-1993	unknown	127,988	7,396	6.13%	-0.0788	1.4268	1.3480	1.1917	1.1917
1991-1992	unknown	120,592	(12,451)	-9.36%	-0.0440	1.4268	1.3828	1.1518	1.1518
1990-1991	unknown	133,043			-0.0430		1.3838	1.2797	1.2797
Average:				1.59%	0.0232	1.4132	1.4420	1.1902	1.1983

* The Firm Peak Day Sendout and all related amounts in columns 13, 14, and 18 for all years prior to 1997-98 have been corrected.
** The calculated historic average of "Design-Day per Customer" excludes the 1995-96 design-day per customer projection of 1.2923 Mcf/day which, as discussed in Docket No. G011/M-95-1145, was incorrectly calculated.
*** The total entitlement for 2002-2003 includes the 7,410 Mcf/day of entitlement permanently released to Cornerstone.

**** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	Total NNG	Iowa GS	Nebraska GS	05-1728 Peoples Mn GS	05-1727 NMU GS	Total	06-1536 Peoples Mn GS	06-1535 NMU GS	Total
NNG Design Day	618,821	187,499	207,704	200,421	23,197	618,821	200,484	21,635	222,119
Customer Requirements moving to Transportation	25,490	6,330	18,635	400	125	25,490	0	0	0
For NMU - VGT Design Day					11,506			11,179	
For NMU - GLGT Design Day					17,688			18,422	
For NMU - Centra Deisgn Day					9,716			9,824	
Adjusted NNG Design Day	593,331	181,169	189,069	200,021	23,072	593,331	200,484	21,635	222,119
Adjusted NNG Design Day Percentages	100.00%	30.53%	31.87%	33.71%	3.89%	100.00%	90.26%	9.74%	100.00%
Total NNG Design Day Capacity	623,310	190,323	198,622	210,127	24,238	623,310	227,526	21,635	249,161
Total NMU Design Day Capacity					61,982			61,060	
Less: NGPL adjusted for nonrecallable releases	(89,276)	(2,795)	(86,481)	0	0	(89,276)	0	0	0
Less: Windom	(2,500)	0	0	2,500	0	2,500	2,500	0	2,500
Less: LS Power	(29,120)	0	(23,000)	6,120	0	(16,880)	29,100	0	29,100
Less: Northwestern Energy (Ortonville)	0	0	0	0	0	0	0	0	0
Less: Chisago delivery to Viking	0	0	0	0	0	0	7,000	0	7,000
Less: TF12B	(9,216)	(2,738)	(551)	5,927	0	2,638	0	0	0
Less: TF5	(28,009)	(10,312)	(15,624)	2,073	0	(23,863)	0	0	0
Less: TFX(5)	(37,656)	(12,656)	(25,000)	0	0	(37,656)	0	0	0
Less: Contract Demand Units	(100)	(100)		0	0	(100)	0	0	0
Total Design Day Capacity (excluding direct assignments)	427,433	161,722	47,966	193,507	24,238	427,433	188,926	82,695	271,621
Factors for All Winter Capacity	100.00%	37.84%	11.22%	45.27%	5.67%	100.00%	69.56%	30.44%	100.00%
Allocated Entitlements in PGA									
TF12B	151,892	57,469	17,045	68,765	8,613	151,892	42,170	7,340	49,510
TF12V				0	0	0	34,070	5,930	40,000
TF5	187,122	70,799	20,999	84,713	10,611	187,122	36,772	2,102	38,874
TFX12 (112486)				11,318	0	11,318	9,724	0	9,724
TFX(5) (112486)				0	0	0	65,117	5,514	70,631
TFX(5) (112561)				0	0	0	6,000	0	6,000
TFX(5) (112486)	49,917	18,886	5,602	22,598	2,831	49,917	2,073	0	2,073
TFX(5) (12-V)	13,502	5,109	1,515	6,113	766	13,502	0	0	0
TFX12 (111866)				0	0	0	0		0
TFX12 (111866)				0	0	0	0	0	0
TFX5 (111866)	25,000	9,459	2,805	0	1,418	13,682	0	0	0
Total Allocated Entitlements in PGA	427,433	161,722	47,966	193,507	24,238	427,433	195,926	20,886	216,812
Direct Assigned Entitlements in PGA (NNG)									
NGPL	89,276	2,795	86,481	0	0	89,276	0	0	0
Windom	2,500			2,500	0	2,500	2,500	0	2,500
LS Power	29,120		23,000	6,120	0	29,120	29,100	0	29,100
Northwestern Energy (Ortonville)				0	0	0	0	0	0
NNG Zone GDD Call Option				0	0	0	0	0	0
TFX(5)	9,216	2,738	551	5,927	0	9,216	0	0	0
TFX(7)	28,009	10,312	15,624	2,073	0	28,009	0	0	0
TFX(5)	37,656	12,656	25,000	0	0	37,656	0	0	0
TFX7 chg to TFX12 (111866)*				0	0	0	0	0	0
Total Direct Assignments	195,777	28,501	150,656	16,620		195,777	31,600		31,600
Total Capacity before Peak Shaving	623,210	190,223	198,622	210,127	24,238	623,210	227,526	20,886	248,412
LP Peak Shaving	0	0	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	623,210	190,223	198,622	210,127	24,238	623,210	227,526	20,886	248,412
Total Transp. (with TFX Offpeak less LSP)				262,081			198,426		
Total Annual Transportation				68,765			76,240		
Total Seasonal Transportation				115,497			38,845		
Total Percent Seasonal				55.0%			17.1%		
LS Power as % of Total DD Capacity				2.9%			12.8%		
Reserve Margin				5.05%			13.49%		
Direct Assigned Entitlements in PGA (NMU)									
Viking FT-A (AF 0012)					8,366			7,966	
Viking FT-A backhaul					1,900			4,625	
Viking FT-A (AF 0014)					0			0	
Viking FT-A (AF 0102)					0			0	
Viking FT-A (AF 0183)					0			0	
Viking Chisago TF 12 (112495) B					1,303			2,546	
Viking Chisago TF 12 (112495) V					0			0	
Viking Chisago TF 5 (112495)					2,839			2,078	
Viking Chisago TF 12 (112486)					0			0	
Viking Chisago TF 5 (112486)					0			0	
Great Lakes T-16 & T-155 -12					13,130			11,308	
Great Lakes T-16 & T-155 -5					0			2,138	
Great Lakes FT8466-12					0			0	
Great Lakes FT15782-12					0			0	
Centra FT-1					8,358			9,858	
Centra -Boise					1,500			0	
Nexen Storage					4,600			6,000	
Tenaska PSO GL					86,549			0	
Wadena Delivered Option					0			0	
Tenaska PSO Centra					62,000			0	
ANR Storage	0	0	0	0	0	0	0	0	0
Total Capacity					212,883			62,780	
Total NNG transportation					24,238			20,886	
Total Annual Transportation					59,734			56,780	
Total Seasonal Transportation NNG					15,625			7,616	
Total Percent Seasonal on NNG					64.5%			36.5%	
Reserve Margin					3.79%			2.82%	

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	Total NNG	Iowa GS	Nebraska GS	05-1728 Peoples Mn GS	05-1727 NMU GS	Total	06-1536 Peoples Mn GS	06-1535 NMU GS	Total
Direct Assigned Demand Not in PGA									
TF-12-B Contract Demand	100	100	0	**0**	0	100	**0**	0	0
Total Design Day Capacity w/ contract demand	623,310	190,323	198,622	**210,127**	24,238	623,310	**227,526**	20,886	248,412
Factors	100.00%	30.53%	31.87%	**33.71%**	3.89%	100.00%	**90.26%**	9.74%	100.00%
Other Entitlements not included in Peak Day Deliverability									
Field TF (TFF) (NMU direct assigned)				**0**			**0**	0	0
TFX Offpeak Old Oct. (60,000)	60,000	18,321	19,119	**20,227**	2,333	60,000	**0**	0	0
TFX Offpeak Old Oct. (35,000)	35,000	10,687	11,153	**11,799**	1,361	35,000	**0**	0	0
TFX Offpeak New Oct. (14,600)	14,600	4,458	4,652	**4,922**	568	14,600	**0**	0	0
TFX Offpeak New Apr. (39,600)	39,600	12,092	12,619	**13,350**	1,540	39,600	**0**	0	0
TFX Oct				**0**	0		**2,000**	0	2,000
TFX Apr				**0**	0		**0**	0	0
TFX7 chg to TFX12 (111866)*				**0**	0		**0**	0	0
TFX Apr-Oct	8,469	2,586	2,699	**2,855**	329	8,469	**0**	0	0
TFX May-Sept	14,600	4,458	4,652	**4,922**	568	14,600	**0**	0	0
FDD Storage reservation (112490)	138,913	42,416	44,266	**46,830**	5,402	138,913	**69,094**	6,343	75,437
FDD Storage capacity MSQ **1/**	8,009,080	2,445,510	2,552,148	**2,699,984**	311,437	8,009,080	**3,983,639**	365,682	4,349,321
FDD Storage reservation (113704)	0	0	0	0	0	0	0	0	0
FDD Storage capacity MSQ **2/**	0	0	0	0	0	0	0	0	0
FDD Storage reservation (118215)	0	0	0	0	0	0	0	0	0
FDD Storage capacity MSQ **3/**	0	0	0	0	0	0	0	0	0
FDD Storage reservation (118657)	0	0	0	0	0	0	0	0	0
FDD Storage capacity MSQ **4/**	0	0	0	0	0	0	0	0	0
ANR Capacity	0	0	0	**0**	0	0	**0**	0	0
Nexen PSO	255,000	77,862	81,258	**85,964**	9,916	255,000	**0**	600,000	600,000
Tenaska PSO	500,000	152,671	159,328	**168,558**	19,443	500,000	**172,193**	15,807	188,000
NGPL	3,558,225	1,086,476	1,133,853	**1,199,532**	138,364	3,558,225	**0**	0	0
SMS	54,000	16,488	17,207	**18,204**	2,100	54,000	**20,773**	1,907	22,680
SBA				**0**	0	0	**0**	0	0
Upstream Demand per Mo				**0**	32	32	**0**	0	0
Bison/NBPL (FT0003 & T8673F)				**0**	0	0	**0**	0	0
AECO Storage				**0**	0	0	**0**	0	0
1/ Cycled Volumes =				**787,676**	5,402	793,078	**796,728**	73,136	869,864
2/ Cycled Volumes =				**0**	0	0	**0**	0	0
3/ Cycled Volumes =				**0**	0	0	**0**	0	0
4/ Cycled Volumes =				**0**	0	0	**0**	0	0

*** = See MERC Reply Comments and DOC Response Comments in Docket No. 09-1284**

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	07-1405 Peoples Mn GS	07-1402 NMU GS	Total	08-1328 Peoples Mn GS	08-1329 NMU GS	Total	09-1284 Peoples Mn GS	09-1282 NMU GS	Total
NNG Design Day	202,263	21,491	223,754	225,397	21,791	247,188	203,360	24,680	228,040
Customer Requirements moving to Transportation	0	0	0	0	0	0	0	0	0
For NMU - VGT Design Day		12,331			10,129			12,198	
For NMU - GLGT Design Day		17,497			24,195			14,848	
For NMU - Centra Deisgn Day		9,690			7,611			9,190	
Adjusted NNG Design Day	202,263	21,491	223,754	225,397	21,791	247,188	203,360	24,680	228,040
Adjusted NNG Design Day Percentages	90.40%	9.60%	100.00%	91.18%	8.82%	100.00%	89.18%	10.82%	100.00%
Total NNG Design Day Capacity	226,785	21,491	248,276	226,785	21,791	248,576	231,064	24,680	255,744
Total NMU Design Day Capacity		61,009			63,726			60,916	
Less: NGPL adjusted for nonrecallable releases	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
Less: LS Power	26,323	2,777	29,100	26,323	2,777	29,100	26,375	2,725	29,100
Less: Northwestern Energy (Ortonville)	0	0	0	0	0	0	0	0	0
Less: Chisago delivery to Viking	7,000	0	7,000	7,000	0	7,000	7,000	0	7,000
Less: TF12B	0	0	0	0	0	0	0	0	0
Less: TF5	0	0	0	0	0	0	0	0	0
Less: TFX(5)	0	0	0	0	0	0	0	0	0
Less: Contract Demand Units	0	0	0	0	0	0	0	0	0
Total Design Day Capacity (excluding direct assignments)	190,962	85,277	276,239	190,962	88,294	279,256	195,189	88,321	283,510
Factors for All Winter Capacity	69.13%	30.87%	100.00%	68.38%	31.62%	100.00%	68.85%	31.15%	100.00%
Allocated Entitlements in PGA									
TF12B	43,858	2,954	46,812	29,906	2,653	32,559	35,221	7,513	42,734
TF12V	15,946	9,802	25,748	32,690	6,643	39,333	24,583	5,243	29,826
TF5	29,619	1,991	31,610	26,827	5,451	32,278	29,619	1,991	31,610
TFX12 (112486)	9,724	0	9,724	9,724	0	9,724	9,724	0	9,724
TFX(5) (112486)	46,558	6,139	52,697	46,558	6,139	52,697	48,754	6,139	54,893
TFX(5) (112561)	6,000	0	6,000	6,000	0	6,000	6,000	0	6,000
TFX(5) (112486)	3,996	0	3,996	3,996	0	3,996	1,800	0	1,800
TFX(5) (12-V)	0	0	0	0	0	0	0	0	0
TFX12 (111866)	414	0	414	414	0	414	414	0	414
TFX12 (111866)	8,271	0	8,271	8,271	0	8,271	9,140	0	9,140
TFX5 (111866)	33,576	0	33,576	33,576	0	33,576	25,013	0	25,013
Total Allocated Entitlements in PGA	197,962	20,886	218,848	197,962	20,886	218,848	190,268	20,886	211,154
Direct Assigned Entitlements in PGA (NNG)									
NGPL	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
LS Power	26,323	2,777	29,100	26,323	2,777	29,100	26,375	2,725	29,100
Northwestern Energy (Ortonville)	0	0	0	0	0	0	0	0	0
NNG Zone GDD Call Option	0	0	0	0	0	0	0	0	0
TFX(5)	0	0	0	0	0	0	0	0	0
TFX(7)	0	0	0	0	0	0	0	0	0
TFX(5)	0	0	0	0	0	0	0	0	0
TFX7 chg to TFX12 (111866)*	0	0	0	0	0	0	11,921	0	11,921
Total Direct Assignments	28,823	2,777	31,600	28,823	2,777	31,600	40,796	2,725	43,521
Total Capacity before Peak Shaving	226,785	23,663	250,448	226,785	23,663	250,448	231,064	23,611	254,675
LP Peak Shaving	0	0	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	226,785	23,663	250,448	226,785	23,663	250,448	231,064	23,611	254,675
Total Transp. (with TFX Offpeak less LSP)	200,462			200,462			204,689		
Total Annual Transportation	59,804			62,596			59,804		
Total Seasonal Transportation	67,191			64,399			56,432		
Total Percent Seasonal	29.6%			28.4%			24.4%		
LS Power as % of Total DD Capacity	11.6%			11.6%			11.4%		
Reserve Margin	12.12%			0.62%			13.62%		
Direct Assigned Entitlements in PGA (NMU)									
Viking FT-A (AF 0012)		7,966			7,966			7,966	
Viking FT-A backhaul		4,987			5,902			5,902	
Viking FT-A (AF 0014)		0			0			0	
Viking FT-A (AF 0102)		0			0			0	
Viking FT-A (AF 0183)		0			0			0	
Viking Chisago TF 12 (112495) B		782			926			1,368	
Viking Chisago TF 12 (112495) V		0			0			955	
Viking Chisago TF 5 (112495)		1,765			2,089			563	
Viking Chisago TF 12 (112486)		1,963			2,324			2,089	
Viking Chisago TF 5 (112486)		476			563			926	
Great Lakes T-16 & T-155 -12		11,308			11,308			11,308	
Great Lakes T-16 & T-155 -5		2,138			2,138			2,138	
Great Lakes FT8466-12		4,500			4,000			3,000	
Great Lakes FT15782-12		0			0			0	
Centra FT-1		9,858			9,858			9,858	
Centra -Boise		0			0			0	
Nexen Storage		0			0			0	
Tenaska PSO GL		0			0			0	
Wadena Delivered Option		0			0			0	
Tenaska PSO Centra		0			0			0	
ANR Storage	0	0	0	0	0	0	0	0	0
Total Capacity		64,419			64,835			63,782	
Total NNG transportation		23,663			23,663			23,611	
Total Annual Transportation		61,642			62,058			61,057	
Total Seasonal Transportation NNG		8,130			11,590			8,130	
Total Percent Seasonal on NNG		34.4%			49.0%			34.4%	
Reserve Margin		5.59%			1.74%			4.70%	

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	07-1405 Peoples Mn GS	07-1402 NMU GS	Total	08-1328 Peoples Mn GS	08-1329 NMU GS	Total	09-1284 Peoples Mn GS	09-1282 NMU GS	Total
Direct Assigned Demand Not in PGA									
TF-12-B Contract Demand	**0**	0	0	**0**	0	0	**0**	0	0
Total Design Day Capacity w/ contract demand	**226,785**	23,663	250,448	**226,785**	23,663	250,448	**231,064**	23,611	254,675
Factors	**90.40%**	9.60%	100.00%	**91.18%**	8.82%	100.00%	**89.18%**	10.82%	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
TFX Offpeak Old Oct. (60,000)	**0**	0	0	**0**	0	0	**0**	0	0
TFX Offpeak Old Oct. (35,000)	**0**	0	0	**0**	0	0	**0**	0	0
TFX Offpeak New Oct. (14,600)	**0**	0	0	**0**	0	0	**0**	0	0
TFX Offpeak New Apr. (39,600)	**0**	0	0	**0**	0	0	**0**	0	0
TFX Oct	**2,000**	0	2,000	**2,000**	0	2,000	**2,000**	0	2,000
TFX Apr	**2,000**	0	2,000	**2,000**	0	2,000	**2,000**	0	2,000
TFX7 chg to TFX12 (111866)*	**10,837**	0	10,837	**10,837**	0	10,837	**0**	0	0
TFX Apr-Oct	**0**	0	0	**0**	0	0	**0**	0	0
TFX May-Sept	**0**	0	0	**0**	0	0	**0**	0	0
FDD Storage reservation (112490)	**68,309**	7,128	75,437	**68,309**	7,128	75,437	**66,871**	6,833	73,704
FDD Storage capacity MSQ **1/**	**3,938,382**	410,939	4,349,321	**3,938,382**	410,939	4,349,321	**3,855,372**	393,949	4,249,321
FDD Storage reservation (113704)	**4,712**	492	5,204	**0**	0	0	**0**	0	0
FDD Storage capacity MSQ **2/**	**271,655**	28,345	300,000	**0**	0	0	**0**	0	0
FDD Storage reservation (118215)	**0**	0	0	**3,141**	328	3,469	**4,722**	482	5,204
FDD Storage capacity MSQ **3/**	**0**	0	0	**181,100**	18,900	200,000	**272,177**	27,822	300,000
FDD Storage reservation (118657)	**0**	0	0	**5,026**	524	5,550	**5,035**	515	5,550
FDD Storage capacity MSQ **4/**	**0**	0	0	**289,765**	30,235	320,000	**290,335**	29,665	320,000
ANR Capacity	**0**	0	0	**0**	0	0	**0**	0	0
Nexen PSO	**0**	669,700	669,700	**0**	684,604	684,604	**0**	684,604	684,604
Tenaska PSO	**170,237**	17,763	188,000	**0**	0	0	**0**	0	0
NGPL	**0**	0	0	**0**	0	0	**0**	0	0
SMS	**20,537**	2,172	22,709	**20,537**	2,143	22,680	**20,577**	2,103	22,680
SBA	**0**	0	0	**0**	0	0	**0**	0	0
Upstream Demand per Mo	**0**	0	0	**0**	0	0	**0**	0	0
Bison/NBPL (FT0003 & T8673F)	**0**	0	0	**0**	0	0	**0**	0	0
AECO Storage	**0**	0	0	**0**	0	0	**0**	0	0
1/ Cycled Volumes =	**787,676**	82,188	869,864	**787,676**	**82,188**	869,864	**771,074**	**78,790**	849,864
2/ Cycled Volumes =	**54,331**	5,669	60,000	**0**	**0**	0	**0**	**0**	0
3/ Cycled Volumes =	**0**	0	0	**36,221**	**3,779**	40,000	**54,437**	**5,563**	60,000
4/ Cycled Volumes =	**0**	0	0	**57,953**	**6,047**	64,000	**58,067**	**5,933**	64,000

*** = See MERC Reply Comments and DOC Response Comm**

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	10-1168 Peoples Mn GS	10-1166 NMU GS	Total	11-1084 Peoples Mn GS	11-1088 NMU GS	Total
NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960
Customer Requirements moving to Transportation	0	0	0	0	0	0
For NMU - VGT Design Day		10,835			11,046	
For NMU - GLGT Design Day		14,964			14,870	
For NMU - Centra Deisgn Day		8,248			8,295	
Adjusted NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960
Adjusted NNG Design Day Percentages	89.18%	10.82%	100.00%	89.88%	10.12%	100.00%
Total NNG Design Day Capacity	233,627	23,615	257,242	221,436	23,778	245,214
Total NMU Design Day Capacity		57,662			57,989	
Less: NGPL adjusted for nonrecallable releases	0	0	0	0	0	0
Less: Windom	2,500	0	2,500	2,500	0	2,500
Less: LS Power	25,951	3,149	29,100	0	0	0
Less: Northwestern Energy (Ortonville)	0	0	0	910	0	910
Less: Chisago delivery to Viking	0	0	0	0	0	0
Less: TF12B	0	0	0	0	0	0
Less: TF5	0	0	0	0	0	0
Less: TFX(5)	0	0	0	0	0	0
Less: Contract Demand Units	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
Factors for All Winter Capacity	70.85%	29.15%	100.00%	72.89%	27.11%	100.00%
Allocated Entitlements in PGA						
TF12B	34,875	4,232	39,107	42,396	4,774	47,170
TF12V	32,290	3,919	36,209	25,298	2,848	28,146
TF5	28,785	3,493	32,278	29,011	3,267	32,278
TFX12 (112486)	9,651	1,171	10,822	9,727	1,095	10,822
TFX(5) (112486)	51,163	6,208	57,371	51,383	5,806	57,189
TFX(5) (112561)	5,351	649	6,000	5,393	607	6,000
TFX(5) (112486)	1,605	195	1,800	1,800	182	1,982
TFX(5) (12-V)	0	0	0	0	0	0
TFX12 (111866)	1,144	139	1,283	1,153	130	1,283
TFX12 (111866)	7,376	895	8,271	7,434	837	8,271
TFX5 (111866)	22,306	2,707	25,013	22,482	2,531	25,013
Total Allocated Entitlements in PGA	194,546	23,608	218,154	196,077	22,077	218,154
Direct Assigned Entitlements in PGA (NNG)						
NGPL	0	0	0	0	0	0
Windom	2,500	0	2,500	2,500	0	2,500
LS Power	25,951	3,149	29,100	0	0	0
Northwestern Energy (Ortonville)	0	0	0	910	0	910
NNG Zone GDD Call Option	0	0	0	11,235	1,265	12,500
TFX(5)	0	0	0	0	0	0
TFX(7)	0	0	0	0	0	0
TFX(5)	0	0	0	0	0	0
TFX7 chg to TFX12 (111866)*	10,631	1,290	11,921	10,715	1,206	11,921
Total Direct Assignments	39,082	4,439	43,521	25,360	2,471	27,831
Total Capacity before Peak Shaving	233,628	28,047	261,675	221,437	24,548	245,985
LP Peak Shaving	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
Total Transp. (with TFX Offpeak less LSP)	207,677			221,437		
Total Annual Transportation	67,165			67,694		
Total Seasonal Transportation	52,696			53,293		
Total Percent Seasonal	22.6%			24.1%		
LS Power as % of Total DD Capacity	11.1%			0.0%		
Reserve Margin	20.06%			4.86%		
Direct Assigned Entitlements in PGA (NMU)						
Viking FT-A (AF 0012)		7,966			7,711	
Viking FT-A backhaul		0			0	
Viking FT-A (AF 0014)		0			678	
Viking FT-A (AF 0102)		0			1,234	
Viking FT-A (AF 0183)		0			1,852	
Viking Chisago TF 12 (112495) B		0			0	
Viking Chisago TF 12 (112495) V		0			0	
Viking Chisago TF 5 (112495)		0			0	
Viking Chisago TF 12 (112486)		0			0	
Viking Chisago TF 5 (112486)		0			0	
Great Lakes T-16 & T-155 -12		11,308			8,445	
Great Lakes T-16 & T-155 -5		2,138			2,238	
Great Lakes FT8466-12		3,000			0	
Great Lakes FT15782-12		0			5,536	
Centra FT-1		9,858			9,858	
Centra -Boise		0			0	
Nexen Storage		0			0	
Tenaska PSO GL		0			0	
Wadena Delivered Option		5,902			0	
Tenaska PSO Centra		0			0	
ANR Storage	0	0	0	0	0	0
Total Capacity		68,219			62,100	
Total NNG transportation		28,047			24,548	
Total Annual Transportation		57,878			55,865	
Total Seasonal Transportation NNG		12,408			11,604	
Total Percent Seasonal on NNG		44.2%			47.3%	
Reserve Margin		18.31%			7.09%	

DOC Attachment 3
Allocation and Direct Assignment
of NNG, GLGT, VGT and Centra Demand Entitlements
between MERC-PNG and MERC-NMU

	10-1168 Peoples Mn GS	10-1166 NMU GS	Total	11-1084 Peoples Mn GS	11-1088 NMU GS	Total
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	**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
Factors	**89.18%**	10.82%	100.00%	**89.88%**	10.12%	100.00%
Other Entitlements not included in Peak Day Deliverability						
Field TF (TFF) (NMU direct assigned)	**0**	0	0	**0**	0	0
TFX Offpeak Old Oct. (60,000)	**0**	0	0	**0**	0	0
TFX Offpeak Old Oct. (35,000)	**0**	0	0	**0**	0	0
TFX Offpeak New Oct. (14,600)	**0**	0	0	**0**	0	0
TFX Offpeak New Apr. (39,600)	**0**	0	0	**0**	0	0
TFX Oct	**1,784**	216	2,000	**1,798**	202	2,000
TFX Apr	**1,784**	216	2,000	**1,798**	202	2,000
TFX7 chg to TFX12 (111866)*	**0**	0	0	**0**	0	0
TFX Apr-Oct	**0**	0	0	**0**	0	0
TFX May-Sept	**0**	0	0	**0**	0	0
FDD Storage reservation (112490)	**67,273**	8,164	75,437	**67,803**	7,634	75,437
FDD Storage capacity MSQ **1/**	**3,878,642**	470,684	4,349,326	**3,909,172**	440,149	4,349,321
FDD Storage reservation (113704)	**0**	0	0	**0**	0	0
FDD Storage capacity MSQ **2/**	**0**	0	0	**0**	0	0
FDD Storage reservation (118215)	**6,187**	751	6,938	**6,236**	702	6,938
FDD Storage capacity MSQ **3/**	**356,700**	43,301	400,002	**359,510**	40,491	400,001
FDD Storage reservation (118657)	**4,949**	601	5,550	**4,988**	562	5,550
FDD Storage capacity MSQ **4/**	**285,370**	34,630	320,000	**287,615**	32,385	320,000
ANR Capacity	**0**	0	0	**0**	0	0
Nexen PSO	**0**	0	0	**0**	0	0
Tenaska PSO	**0**	0	0	**0**	0	0
NGPL	**0**	0	0	**0**	0	0
SMS	**20,226**	2,454	22,680	**20,385**	2,295	22,680
SBA	**0**	0	0	**0**	0	0
Upstream Demand per Mo	**0**	0	0	**0**	0	0
Bison/NBPL (FT0003 & T8673F)	**44,589**	5,411	50,000	**44,940**	5,060	50,000
AECO Storage	**0**	665,043	665,043	**0**	666,223	666,223
1/ Cycled Volumes =	**775,728**	**94,137**	869,865	**781,834**	**88,030**	869,864
2/ Cycled Volumes =	**0**	**0**	0	**0**	**0**	0
3/ Cycled Volumes =	**71,342**	**8,658**	80,000	**71,904**	**8,096**	80,000
4/ Cycled Volumes =	**57,074**	**6,926**	64,000	**57,523**	**6,477**	64,000

*** = See MERC Reply Comments and DOC Response Comm**

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-11-1084

Dated this **12th of March, 2012**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_11-1084_AA-1084
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	OFF_SL_11-1084_AA-1084
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_11-1084_AA-1084
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_11-1084_AA-1084
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	OFF_SL_11-1084_AA-1084
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_11-1084_AA-1084
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	OFF_SL_11-1084_AA-1084
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	OFF_SL_11-1084_AA-1084
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_11-1084_AA-1084
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_11-1084_AA-1084

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_11-1084_AA-1084
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_11-1084_AA-1084
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Paper Service	No	OFF_SL_11-1084_AA-1084