MICHAEL J. AHERN
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November 2, 2009

VIA ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System;
Docket No. ___________________

Dear Dr. Haar:

In accordance with Minnesota Rule 7825.2910, subpart 2, please find the public and nonpublic versions of Minnesota Energy Resources Corporation's (MERC) request to change demand entitlement.

Please note that page 16 of the Petition and Attachments 8, 9, and 15 contain financial information with independent economic value that is not generally known to, and not readily ascertainable by, competitors of MERC, who could obtain economic value from its disclosure. MERC maintains this information as secret. Accordingly this data qualifies as trade secret data as defined in Minn. Stat. § 13.37, subd. 1(b), and MERC requests that the data be treated as trade secret information.

In accordance with Minnesota Rule 7825.2910, subpart 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

Please feel free to contact me at (612) 340-2881 if you have any questions regarding this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - PNG (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC's Minnesota customers served off of the Northern Natural Gas Company (NNG or Northern) system. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2009.

This filing includes the following attachments:

Attachment 1:	Notice of Availability.
Attachment 2:	One paragraph summary of the filing in accordance with Minn. R. 7829.1300, subp. 1.
Attachment 3:	Petition for Change in Demand with Attachments.
Attachment 4:	Affidavit of Service and Service List.

The following information is provided in accordance with Minn. R. 7829.1300:

1. **Summary of Filing**

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing is attached.

2. **Service**

Pursuant to Minn. R. 7829.1300, subp. 2, MERC has served a copy of this filing on the Department of Commerce and the Office of the Attorney General – Residential Utilities Division. The summary of the filing has been served on all parties on the attached service list. Additionally, pursuant to Minn. R. 7825.2910, subp. 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

3. **General Filing Information**

A. Name, Address, and Telephone Number of the Utility

Minnesota Energy Resources Corporation
2665 145th Street West
Box 455
Rosemount, MN 55068-0455
(651) 322-8901

B. Name, Address, and Telephone Number of Attorney for the Utility

Michael J. Ahern
Dorsey & Whitney LLP
50 S. Sixth Street, Suite 1500
Minneapolis, MN 55402-1498
(612) 340-2881

C. Date of the Filing and Proposed Effective Date

Date of filing: November 2, 2009
Proposed Effective Date: November 1, 2009

D. Statute Controlling Schedule for Processing the Filing

Minnesota Statutes and related rules do not provide an explicit time frame for action by the Commission. Under Minn. R. 7829.1400, initial comments are due within 30 days of filing, with reply comments due 10 days thereafter.

E. Utility Employee Responsible for the Filing

Gregory J. Walters
519 First Avenue SW
P.O. Box 6538
Rochester, MN 55903-6538
(507) 529-5100

If additional information is required, please contact Michael J. Ahern at: (612) 340-2881.

DATED: November 2, 2009

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern
Michael J. Ahern
Suite 1500, 50 South Sixth Street
Minneapolis, MN 55402-1498
Telephone: (612) 340-2600

Attorney for Minnesota Energy Resources Corporation

November 2, 2009

To: Service List

RE: Minnesota Energy Resources Corporation-PNG Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-PNG has filed a petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement.

To obtain copies, or if you have any questions, please contact:

Gregory J. Walters
Minnesota Energy Resources Corporation
519 1st Ave SW
Rochester, MN 55902
507-529-5100.

Please note that this filing is also available through the eDockets system maintained by the Minnesota Department of Commerce and the Minnesota Public Utilities Commission. You can access this document by going to eDockets through the websites of the Department of Commerce or the Public Utilities Commission or going to the eDockets homepage at:

https://www.edockets.state.mn.us/EFiling/home.jsp

Once on the eDockets homepage, this document can be accessed through the Search Documents link and by entering the date of the filing.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. ______________
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - PNG (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC's Minnesota customers served off of the Northern Natural Gas Company (NNG or Northern) system. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2009.

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. ______________
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - PNG (MERC or the Company), a division of Integrys Energy Group, Inc. (TEG), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC's PNG customers served off of the Northern Natural Gas Company (NNG or Northern) system.[1] MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2009.

[1] MERC-PNG also serves Minnesota customers off of the Viking Gas Transmission (Viking) pipeline system and the Great Lakes Gas Transmission (GLGT) pipeline system. MERC requests approval of a demand entitlement change for the 2008-2009 heating season for its Viking customers in a separate Docket No., and requests approval of a demand entitlement change on the GLGT system in a separate Docket No.

II. DISCUSSION

A. MERC's PNG-NNG Design Day Requirements

MERC's 2009-2010 NNG design day requirements decreased 22,037 Mcf (or approximately 9.78 percent) from 225,397 Mcf to 203,360 Mcf.

Table 1: MERC's Proposed NNG Reserve Margins
For the 2009-2010 Heating Season
PNG/NMU

	Reserve Margin 2009-2010 Heating Season	Reserve Margin 2008-2009 Heating Season	Change
NNG Zone EF	11.68%	1.32%	10.36%

As shown in Table 1, MERC's proposed system wide reserve margin, Zone EF for the 2009-2010 heating season is positive.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day requirement for Northern Natural Gas (NNG), which includes PNG and NMU is 228,040 Dth as calculated in Attachments 5 and Attachments 7 under the NNG Entitlement Allocation.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day capacity on Northern Natural Gas (NNG), which includes PNG and NMU is 254,675 Dth as calculated in Attachments 5 and Attachments 7 under the NNG Entitlement Allocation. The difference between the total Design Day requirement and total Design Day capacity results in an 11.68% positive reserve margin.

B. Forecast Methodology for MERC Demand Entitlement Nov. 1, 2009

Peakday

Purpose

Gather data and perform analysis used in the "Petition for Change in Demand" for Minnesota Energy Resources Corporation – PNG and Minnesota Energy Resources Corporation – NMU for "Approval of a Change in Demand Entitlement" to be sent to the Minnesota Public Utilities Commission, otherwise known as the "MERC Demand Entitlement Filings".

Background

MERC is composed of two service areas:

1. PNG - Peoples Natural Gas (company – approximately 170,000 customers)
2. NMU - Northern Minn Utility (company – approximately 40,000 customers)

Which are served by four pipelines:

3. VGT - Viking Gas Transmission system (serves both PNG and NMU)
4. NNG- Northern Natural Gas pipeline (serves both PNG and NMU)
5. GLGT - Great Lakes Gas Transmission pipeline (serves both PNG and NMU)
6. Centra - Centra pipeline (serves NMU)

Four Petitions for Change in Demand are filed (one for each of PGAC):

A. PNG customers served off of VGT = PNG - VGT

B. PNG customers served off of GLGT = PNG - GLGT

C. PNG customers served off of NNG = PNG - NNG

D. All NMU customers - served off NNG, GLGT, VGT & Centra = NMU

Weather data is obtained from six weather stations:

1. International Falls

2. Bemidji

3. Cloquet

4. Fargo

5. Minneapolis

6. Rochester

For analytical purposes, data is subdivided, analyzed and regressed by the following eight demand areas:

	Demand Area (Service Area / Pipeline)	**PGAC**	**Weather Station(s)**
1	NMU-Centra	NMU	International Falls
2	NMU-GLGT *	NMU	Bemidji & Cloquet
3	NMU-NNG	NMU	Cloquet
4	NMU-VGT *	NMU	Fargo
5	NMU-GLGT&VGT*	NMU	Bemidji
6	PNG-GLGT	PNG-GLGT	Bemidji
7	PNG-NNG	PNG-NNG	Minneapolis, Rochester & Cloquet
8	PNG-VGT	PNG-VGT	Fargo

* Thief River Falls is included only in NMU-GLGT&VGT

Analytical Approach

Summary

1. Obtain daily weather data for each weather station as shown in Attachment 13

2. Obtain daily total throughput volumes by pipeline

3. Perform total throughput peak day regressions

4. Subtract interruptible, transport, and joint interruptible expected peak day load volumes based on monthly billing data

5. Add back Daily Firm Capacity (DFC) customer selections

6. Apply sales forecast growth rates

Detail

The Peak Day Forecasting Team (the Team) followed a data-driven approach for the MERC Peak Day Forecast. Since the forecast is for a peak day, the best daily data available is required to provide the best estimate. Theoretically, the peak day regression should be performed using daily net firm load by service area, pipeline, and weather station. A review of the data available indicated that the two best daily data sources are the daily weather data by weather station and the daily throughput data by Town Border Station (TBS) and pipeline meter. (Some pipeline meters are dedicated to a TBS, and some are dedicated to individual customers.)

Most of the interruptible, transportation, and joint interruptible data available is from monthly billing record excerpts provided by ADS/Vertex, an external vendor that has been providing billing services to MERC-PNG and MERC-NMU.

The Team followed an approach generally consistent with the one used last year that would:

- Make the best use of the best available data; and
- Isolate the effects the monthly billing cycle data has on the Peak Day forecast so that the new process can be easily updated as better data is available.
- Provide a basis for future risk adjustment to the forecast.

The Peak Day Process consisted of:

I. Data Preparation
II. Regression Generation of Net Daily Metered Volumes
III. Volume Risk Adjustments
IV. Adjusting the Regression Results to a Firm peak day estimate

I. The **Data Preparation** Steps consisted of:

- Identify the coldest Adjusted Heating Degree Day (AHDD65) in the last 20 years for each weather station.
- Determine the most recent three years of December through February daily total metered throughput for the eight demand areas by weather station.
- Subtract the daily pipeline meter readings for all non-firm customers with daily pipeline meter readings available for all three December through February years from the total throughput for each demand area and weather station. Use the resulting net daily metered volumes for regressions. Examples of non-firm customer meter readings subtracted from the demand area total daily throughputs are paper mills, direct-connects, taconites, and off-system end users. (see “Adjusting the Regression Results to a Firm Peak Day Estimate” below)
- Determine how to map the monthly billing data to the eight demand areas.

Each daily weather station data file was searched to find the coldest Adjusted Heating Degree Day (AHDD65) in the last 20 years. This 1-in-20 approach is consistent with prior years. The results are provided in the following table:

Station	**Date**	**Avg. Temp**	**Avg. Wind**	**HDD65**	**AHDD65**
Bemidji	2/1/1996	-34	8	99	107
Cloquet	2/2/1996	-31	7	96	103
Fargo	1/18/1996	-16	34	81	109
International Falls	2/2/1996	-34	8	99	107
Minneapolis	2/2/1996	-25	8	90	97
Rochester	2/2/1996	-27	10	92	101

The daily throughput data was provided by pipeline and meter, with each meter on each pipeline mapped to one of the weather stations shown in the above chart. Each meter was also designated as either PNG or NMU. As noted above, some of the meters represented a TBS. Some meters were dedicated to a customer who is not a firm service customer of either PNG or NMU. For example, certain transportation, interruptible, direct-connect, and taconite customers have their own meter, but are not counted as firm service customers.

In a more nearly ideal world, the Team would have also had daily telemetered data from each interruptible, transportation, and joint interruptible customer mapped to each of the eight demand areas and related weather stations. This was the case for a handful of paper mills, direct-connects, taconites, and off-system end users. The rest of the interruptible, transportation, and joint interruptible data was available based on monthly billing cycle data that introduces billing lag, meter read lag (not all meters were read every month resulted in billing cycle estimates and reversals), and other potential errors into their volumes.

Similar to the process used the prior year, the Team generated regressions of the daily throughput data available less the known daily meter readings for non-firm customers and adjusted those regressions for the estimated peak day impact of the other non-firm customers who do not have daily readings. This approach was used because it introduced much less error into the data and regressions than trying to guess how to allocate monthly billing cycle data to daily when the load factors and relative temperature sensitivity of the non-daily-metered customers was not known. Using only the daily metered data for the regressions makes the best use of the best data available and provides insights into the total daily metered load that could be active on a peak day even if supply access at the non-firm pipeline meters were shut off.

II. The **<u>Regression Generation of Net Daily Metered Volumes</u>** consisted of:

- For each of the eight Demand Areas (Service Area / Pipeline):
    1. Gather the net daily metered volumes and weather station data including AHDD65[2] .
    2. If more than one weather station is represented in a given demand area, weight each weather station's AHDD65 by the total December through February metered volumes attributable to that weather station
    3. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer shifts. Month indicator variables are used to isolate load that changes based on winter month, such as businesses that are open extra hours in December and resume normal operating hours in January.
    4. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
    5. Summarize the Baseload and Use/AHDD65 from each regression.
    6. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 in 20 years (volume weighted if using more than one weather station in a single Demand Area).

[2] Temperature and weather data was obtained from Weather Bank/DTN via TherMaxx then converted to HDD65 and AHDD65 in an Excel spreadsheet by MERC – Gas Supply. Temperature and wind data is 24-hour average based on 9am to 9am gas day.

III. Volume Risk Adjustments

For the 2010 forecast, volume risk adjustments were incorporated into the forecast to provide a confidence level that the daily metered load under design conditions would not exceed the daily metered regression estimate. An appropriate volume risk adjustment was determined for each regression group by multiplying the standard error of each regression analysis (sigma) by a factor needed to attain a desired confidence level. The desired confidence level chosen was 97.5%.

IV. Adjusting the Regression Results to a Firm Peak Day Estimate consisted of:

A. Subtract interruptible, transport, and joint interruptible expected peak day load volumes based on monthly billing data

In order to determine firm peak day load, volumes contained in the daily pipeline meter readings for interruptible, joint interruptible and transportation customers needed to be isolated and removed. While it would have been ideal to have daily billing data for all customers, most of the interruptible, transportation, and joint interruptible data was, in most cases, only available from monthly billing records[3]. An unfortunate, but unavoidable consequence was that this data was based on monthly billing cycles that introduce billing lag, meter read lag (not all meters were read every month resulted in billing cycle estimates and reversals), and other potential errors into their volumes.

A database of volumes billed for all customers the prior winter was obtained. The database contained detail by customer class[4], calendar month, (service) area, city, location, zip code and

[3] Individual daily volumes were available for a handful of paper mills, direct-connects, taconites, and off-system end users.

[4] Transportation, Interruptible, Joint Interruptible, Residential, Large Commercial & Industrial and Small Commercial & Industrial.

responsibility center. The billing database was provided by ADS/Vertex, an outside firm that has been providing billing services to MERC. Sales and Revenue Forecasting had previously adjusted the billing data to properly fit the appropriate calendar month of consumption by apportioning billed volumes, i.e. for a bill covering February 15 to March 15, volumes were split evenly between February and March.

Volumes for the interruptible, transportation and joint interruptible customer classes (INTER, TRANS and JINTER classes) needed to be mapped to the appropriate regression demand area, and were then summed. This billing data included consumption that was billed, but not included in the daily metered volumes for several large specific customers (paper mills, direct-connects, taconites, and off-system end users), and therefore needed to be removed from the gross interruptible, transportation and joint interruptible totals. Such customers were identified, mapped to the demand areas, summed and subtracted from the interruptible, transportation and joint interruptible customer classes totals. The following peak demand estimation method based on the highest monthly total from the prior winter was then used to calculate the amount to subtract from the results of the data regressions for each demand area:

The MERC-PNG and MERC-NMU tariff General Rules, Regulations, Terms, and Conditions Section 1.N "Maximum Daily Quantity (MDQ)" on Original Sheet No. 8.04:

N. <u>Maximum Daily Quantity (MDQ):</u>

The amount calculated by dividing the volumes consumed by a particular customer during the highest historical peak month of usage for that customer by twenty (20). Company will estimate a peak month for new customers. A Maximum Daily Quantity may also be established through direct measurement or other means (i.e. estimating the peak *day requirements after installation of new processing equipment or more energy efficient heating systems) if approved by [the] Company.*

B. Add back Daily Firm Capacity (DFC) customer selections

While interruptible, joint interruptible and transportation customer volumes were removed (as described above), in order to determine firm peak day load, daily firm capacity selections needed to be added back. The Sales and Revenue Forecasting department provided historical monthly DFC data for the "joint interruptible" customers from January 2008 through March 2009 that showed the volume that each customer has selected to receive as firm service from MERC each month. Based on the direction from MERC Gas Supply, the Small Volume Joint Firm/Interruptible customers who were relying on MERC to provide peak day firm supply were identified and their daily firm capacity volumes were summed by month for each demand area. The total volumes for January 2009 were then added back to the adjusted regression results.

C. Apply Sales Forecast Growth Rates

The throughput volumes used in the data regressions were from December 2006 through February 2009 and needed to be adjusted to properly forecast 2010. The sales forecast "MERC Fcst 200904", as approved by the Gas Planning Committee, was used to determine a growth rate for each demand area. Because the Peak Day Forecast is based on firm load, General Service volumes (GS - residential, commercial and industrial firm) were used as a proxy to calculate growth rates. These growth rates were then applied to the adjusted regression results.

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

NMU-GLGT

Paper Mills = Ainsworth and Blandon in Bemidji, and Sappi and USG in Cloquet

NMU-VGT

Note: Lamb Weston (RDO) was included in the regression analysis, and therefore, not removed with the interruptible and transportation volumes.

PNG-NNG

Taconites / Direct Connects =

- CCI EMPIRE IND DEL PT 2 TILDEN
- CCI NORTHSHORE
- EVELETH TACONITE
- HIBBING TACONITE CO.
- U.S. STEEL
- NATIONAL STEEL PELLET
- COTTAGE GROVE TBS LS POWER
- INLAND STEEL
- HANNA MINING

PNG-NNG

OSEU (EndUsers) =

- CORRECTIONAL CTR
- GRAND CASINO HINCKLEY (no longer being served gas behind a MERC TBS as of December 2008)
- KEMPS LLC
- KERRY BIO-SCIENCE
- LAKESIDE
- LAND OF LAKES
- PRO-CORN
- SWIFT

B. Daily Firm Capacity

PNG-VGT

CUSTOMER NAME	FIRM CAPACITY
DETROIT LAKES MIDDLE SCHOOL	4
ROSSMAN SCHOOL	.3
BEST WESTERN	32
TOTAL	36.3

PNG-GLGT

CUSTOMER NAME	FIRM CAPACITY
AMERIPRIDE/WPS SERVICES INC	25
ELDERCARE	6.1
NORTHLAND APTS	10.2
NW TECH COLLEGE – BEMIDJI	111
BEM ISD #31-JW SMITH ELEM	41
BEM ISD #31-CENTRAL ELEM	25
TOTAL	218.3

Daily Design Day Estimate to Actual Comparison

In the 2007 demand entitlement dockets, MERC agreed to include a daily estimate utilizing the design day model which is calculated in Attachment 13. The daily estimate is compared to actual consumption. The actual volumes are total through-put which includes interruptible and transportation volumes that are located behind MERC citygates. This does not include any transportation volumes that are directly connected with NNG pipeline. The Design Day model only calculates firm volumes. MERC does not forecast on a daily/monthly basis utilizing the Design Day model. The Design Day model is utilized to calculate the theoretical peak day. The calculated base load natural gas usage at zero heating degree days is 30,580 Dth which includes interruptible and transportation volumes. Since daily volume consumption is not available for all interruptible and transportation customers, MERC is not able to determine an exact number to deduct from the 30,580 Dth to determine the firm base load natural gas consumption at zero (0) HDD.

Average Customer Counts

In the 2007 demand entitlement dockets, MERC agreed to include average customer counts which is provided in Attachment 14.

C. MERC's Specific PNG Proposed Northern System Demand-Related Changes

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC's PNG Northern system customers during winter peak periods. The second type does not affect design day deliverability levels, but alters the capacity portfolio and the PGA costs recovered from customers.

1. Design Day Deliverability Changes

As shown in Attachment 3, MERC-PNG-NNG proposes no changes in total heating season. There was an overall increase in proposed entitlement level. MERC acquired an additional 4,227 volumes from NNG as part of the Northern Lights Project and due to an allocation of LS Power between PNG and NMU, an additional 52 volumes is allocated to PNG-NNG, the Company proposes changes to its portfolio of capacity services identified below in Table 4.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)
TF12B & TF12V	(2,792) Mcf/Day
TF5	2,792 Mcf/Day
TFX12	1,953 Mcf/Day
TFX5	2,274 Mcf/Day
LS Power	52 Mcf/Day
Total Overall Change	4,279 Mcf/Day

2. Other Demand Entitlement Changes

As shown in the Attachment 10, MERC's PNG_NNG proposes an increase of Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability.

D. <u>Financial Option Units and Premiums</u>

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2009/2010 winter (November through March). Please see Attachment 8.

ii. Total premium costs to enter into the financial Call Options on behalf of MERC's firm customers amounted to $2,672,519 for the 2009/2010 winter. Please see Attachment 8.

iii. MERC entered into **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** Total premium per contract is approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** Please see Attachment 8.

iv. Please see Attachment 8 for the various contract dates.

v. Please see Attachment 8 for the various contract prices.

vi. MERC believes a diversified portfolio approach towards hedging is in the best interest of MERC's firm customers. MERC implemented a 40% fixed price (storage and physical fixed price purchases), 30% financial call options and 30% market based prices, assuming normal weather. A dollar-cost-averaging approach is utilized in purchasing the hedging portfolio. Although this hedging strategy will most likely not provide the lowest priced supply, it does meet MERC's stated objectives of providing reliable and reasonably priced natural gas and mitigates natural gas price volatility. Please see Attachment 9, Page 1 of 2.

E. <u>Gas Supply.</u>

The PNG_NNG 2009-2010 Winter Portfolio Plan - Minnesota Energy Resources Corporation for NNG gas supply purchases for the Hedging Plan is in Attachment 9 page 2. This Attachment includes the projected sales number by month for the November 2009 through March 2010 period as well as the planned physical fixed price, financial call options and storage and/or exchange volumes by month.

F. <u>Price Volatility</u>

MERC hedging strategy as described in section 2.(D.)(vi.) provides the opportunity to ensure MERC customers are seventy percent (70%) hedged assuming normal winter volumes. The 70% hedged is accomplished by 40% of normal winter volumes hedged by a fixed price, which is comprised of storage and physical fixed price purchases. MERC is projecting the weighted average cost of gas (WACOG) for physical fixed price purchases of natural gas to be approximately $5.05. Please see Attachment 15, page 1 of 3. MERC is projecting the storage WACOG on NNG to be approximately $3.20. This is an estimate based upon the purchases in October but since this is report is filed before the accounting is closed for October, this estimate may change. Please see Attachment 15, page 2 of 3. The remaining 30% of the 70% is hedged by financial call options. MERC purchased call options at an average strike price of $6.10, which means if NYMEX contract(s) settle above that price, the options are exercised and MERC's customers gas cost is capped at the average strike price. Please see Attachment 15, page 3 of 3. Since financial options are paper only MERC purchases physical index supply to back the financial call options. MERC projects the gas costs to be approximately $4.73 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $6.10 strike price plus the physical index basis spread. If the NYMEX prices are below the average $6.10 strike price, the average natural gas cost for 70% of the normal winter volumes will be lower. The remaining 30% of normal winter volumes are purchasesgild at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium or margin costs.

G. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in it monthly PGA effective November 1, 2009. Rate impacts associated with this change can be found on Attachment 4 pages 1 through 3 and on page 1 of Attachment 11. MERC has also calculated the rate impact of moving the cost recovery of FDD Storage contracts from the demand cost recovery portion of the monthly PGA to the commodity cost recovery portion of the monthly PGA. Attachment 4, pages 4 through 6 and Attachment 11, page 2 illustrate the rate impact created by this shift in cost recovery.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2009. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 2, 2009

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern
Michael J. Ahern
Suite 1500, 50 South Sixth Street
Minneapolis, MN 55402-1498
Telephone: (612) 340-2600

Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Sarah J. Kerbeshian, being first duly sworn on oath, deposes and states that on the 2nd day of November, 2009, the Petition of Minnesota Energy Resources Corporation was electronically filed with the Minnesota Public Utilities Commission and the Minnesota Department of Commerce. A copy of the filing was provided via United States first class mail to the individuals on the attached service list at the Office of the Attorney General, and a summary of the filing was provided via United States first class mail to the remaining individuals on the attached service list.

/s/ Sarah J. Kerbeshian

Subscribed and sworn to before me
this 2nd day of November, 2009.

Joni K. Vincent
Notary Public, State of Minnesota

Burl W. Haar
MN Public Utilities Commission
350 Metro Square Building
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MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND SUMMARY

NOVEMBER 1, 2009

NNG

Design Day Requirement		203,360
Total Peak Day Entitlement		231,064
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 15)	176,225
Firm Annual Throughput - Minnesota		20,263,526
No. of Firm Customers		157,670
Department Load Factor Calculation		31.50%

MINNESOTA ENERGY RESOURCES - PNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2009
NNG

Pipeline Group	Nov08-Mar 09 Avg. Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	Nov08-Mar09 Avg. Customer Growth	Total *
PEAK										
PNG	157,670	157,670	99	30,580	2,337	263,960	57,265	206,695	-1.60%	203,360
Total	157,670	157,670								203,360
OFF PEAK										
PNG	157,670	157,670	55	30,580	2,337	159,112	30,138	128,974	-1.60%	126,892
Total	157,670	157,670								126,892

* Adjusted for customer growth

Footnote 1: Regression Total is based on total through-put data.
Footnote 2: Regression Adjustment substracts out Interruptible, Transportation and Joint Interruptible volumes and adds adjustment to achieve 97.5% confidence lev confidence level that actual demand under design conditions will not exceed estimate.
Footnote 3: Total equals Regression Total minus Regression Adjustment.

*55 is the 30 yr unadjusted heating degree days from NOAA, not adjusted for windspeed.

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND PER CUSTOMER - GS

NOVEMBER 1, 2009

NNG

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
09/10	157,670	203,360	1.29
08/09	156,973	225,397	1.44
07/08	155,910	202,263	1.30
06/07	149,049	200,484	1.35
05/06	148,308	200,421	1.35
04/05	143,896	207,834	1.44
03/04	140,705	198,521	1.41

MINNESOTA ENERGY RESOURCES - PNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2010

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	5,780,362	14,483,164	20,263,526
SVI	527,961	947,186	1,475,147
SVJ	0	0	0
LVI	238,142	427,237	665,379
LVJ	0	0	0
SLV	0	0	0
Total	6,546,465	15,857,587	22,404,052

MINNESOTA ENERGY RESOURCES - PNG

ENTITLEMENT LEVELS

PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2009

		NNG	
Type of Capacity or Entitlement	**Current Amount Mcf or MMBtu**	**Proposed Change Mcf or MMBtu**	**Proposed Amount Mcf or MMBtu**
TF-12 Base & Variable	62,596	(2,792)	59,804
TF5	26,827	2,792	29,619
TFX - 12	29,246	1,953	31,199
TFX - 5	79,293	2,274	81,567
TFX-Offpeak*	2,000	0	2,000
Windom	2,500	0	2,500
LSP Peaking Service	26,323	52	26,375
Heating Season Total	**226,785**	**4,279**	**231,064**
Non-Heating Season Total	96,342	(839)	95,503
Heating Season Forecasted Design Day-Adjusted	225,397	(22,037)	203,360
Non-Heating Season Forecasted Design Day	155,261	(28,369)	126,892
Heating Season Capacity Surplus/Shortage	1,388	26,316	27,704
Non-Heating Season Capacity Surplus/Shortage	(58,919)	27,530	(31,389)

*Not included in total firm entitlement

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
November 1, 2009
NNG

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-07- Oct .07	Last Demand Change G011- M-08- Oct. 08	Most Recent PGA Oct. 2009	Current Proposal Effective Nov.1,2009	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:		**125**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	($3.6940)	($0.9718)	33.89%	$1.2675
Demand Cost	$1.1197	$1.1741	$1.0903	$1.0883	$1.0564	($0.0633)	($0.0339)	-2.93%	($0.0319)
Commodity Margin	$1.6263	$1.1771	$1.6263	$1.6263	$1.6263	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$11.4474	$9.2194	$8.6958	$6.4545	$7.6901	($3.7573)	($1.0057)	19.14%	$1.2356
Avg Annual Cost	$1,429.40	$1,151.20	$1,085.82	$805.96	$960.25	($469.16)	($125.57)	19.14%	$154.2907
Effect of proposed commodity change on average annual bills:									$158.27
Effect of proposed demand change on average annual bills:									($3.98)
2) Small Vol. Interruptible: Avg. Annual Use:		**4,080**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	($3.6940)	($0.9718)	33.89%	$1.2675
Demand Cost									
Commodity Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.7682	$7.2226	$4.9833	$6.2508	($3.6940)	($0.9718)	25.43%	$1.2675
Avg Annual Cost	$40,572.00	$31,692.08	$29,466.19	$20,330.47	$25,501.51	($15,070.49)	($3,964.67)	25.43%	$5,171.0451
Effect of proposed commodity change on average annual bills:									$5,171.05
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**19,053**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	($3.6940)	($0.9718)	33.89%	$1.2675
Demand Cost									
Commodity Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.0606	$7.1282	$6.3384	$4.0991	$5.3666	($3.6940)	($0.9718)	30.92%	$1.2675
Avg Annual Cost	$172,633.79	$135,815.31	$120,767.06	$78,101.14	$102,251.12	($70,382.67)	($18,515.94)	30.92%	$24,149.9817
Effect of proposed commodity change on average annual bills:									$24,149.98
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,080**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	($3.6940)	($0.9718)	33.89%	$1.2675
Demand Cost	$13.4177	$13.1430	$12.0195	$10.3925	$9.3592	($4.0585)	($2.6603)	-9.94%	($1.0333)
Commodity Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.0724	$1.5000	$2.0724	$2.0724	$2.0724	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.7682	$7.2226	$4.9833	$6.2508	($3.6940)	($0.9718)	25.43%	$1.2675
Total Demand Cost	$15.4901	$14.6430	$14.0919	$12.4649	$11.4316	($4.0585)	($2.6603)	-8.29%	($1.0333)
Avg Annual Cost	$40,959.25	$32,058.16	$29,818.48	$20,642.09	$25,787.30	($15,171.95)	($4,031.18)	24.93%	$5,145.2138
Effect of proposed commodity change on average annual bills:									$5,171.05
Effect of proposed demand change on average annual bills:									($25.83)
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	($3.6940)	($0.9718)	33.89%	$1.2675
Demand Cost	$13.4177	$13.1430	$12.0195	$10.3925	$9.3592	($4.0585)	($2.6603)	-9.94%	($1.0333)
Commodity Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$0.1658	$1.2000	$1.6579	$1.6579	$1.6579	$1.4921	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.0606	$7.1282	$6.3384	$4.0991	$5.3666	($3.6940)	($0.9718)	30.92%	$1.2675
Total Demand Cost	$13.5835	$14.3430	$13.6774	$12.0504	$11.0171	($2.5663)	($2.6603)	-8.57%	($1.0333)
Avg Annual Cost	$135,487.13	$106,865.34	$95,094.00	$61,738.52	$80,472.00	($15,134.64)	($14,622.00)	30.34%	$18,733.4736
Effect of proposed commodity change on average annual bills:									$18,810.97
Effect of proposed demand change on average annual bills:									($77.49)

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-09-896
*Implemented with Interim rates
**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

November 1, 2009

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE 01-Nov-09

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$7.5776	$15.1530	$10.7340	$0.0000	$10.7340
TF-12V	$9.0926	$6.4838	$8.0056	$0.0000	$8.0056
TF-5		$7.6050	$7.6050	$0.0000	$7.6050
TFX	$4.5600	$9.6288	$6.6720	$0.0000	$6.6720
FIELD TF			$0.0000	$0.0000	$0.0000
Commodity From Schedule D					$4.9935

V. ANNUAL SALES -- As filed in Docket No. G007,011/MR-08-836

Total Northern Annual Sales 209,429,630 therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-09

	Contract Type	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	GS-1 Rate Case Sales (therm)	Rate ($/therm)
A. GS-1	TF12-B (Max Rate)	Annual	30,021	12	$7.5776	$2,729,840	189,613,000	$0.01440
	TF12-V (Max Rate)	Annual	24,583	12	$9.0926	$2,682,276	189,613,000	$0.01415
	TF5 (Max Rate)	Winter	29,619	5	$15.1530	$2,244,084	189,613,000	$0.01184
	TF12B (Discount-Winter)	Winter	5,200	12	$6.4838	$404,591	189,613,000	$0.00213
	TF5 (Discount-Winter)	Winter	0	5	$7.6050	$0	189,613,000	$0.00000
	TFX5 (Discount)	Winter	6,000	5	$4.5600	$136,800	189,613,000	$0.00072
	TFX12 (Max Rate)	Annual	9,724	12	$9.6288	$1,123,569	189,613,000	$0.00593
	TFX Apr (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX Oct (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX5 (Max Rate)	Winter	48,754	5	$15.1530	$3,693,847	189,613,000	$0.01948
	TFX5 (Discount)	Winter	0	5	$13.8736	$0	189,613,000	$0.00000
	TFX5 (Discount)	Winter	1,800	5	$7.6050	$68,445	189,613,000	$0.00036
	TFX12 (Discount)	Annual	414	12	$4.8667	$24,178	189,613,000	$0.00013
	TFX12 (Discount)	Annual	9,140	12	$5.4570	$598,524	189,613,000	$0.00316
	TFX7 (Discount)	Summer	11,921	12	$2.2204	$317,633	189,613,000	$0.00168
	TFX5 (Discount)	Winter	122	5	$4.8667	$2,969	189,613,000	$0.00002
	TFX5 (Discount)	Winter	2,702	5	$5.4570	$73,724	189,613,000	$0.00039
	TFX5 (Discount)	Winter	22,189	5	$15.1475	$1,680,539	189,613,000	$0.00886
	SMS	Annual	20,577	12	$2.1800	$538,294	189,613,000	$0.00284
	FDD - Reservation	Annual	66,871	12	$1.7140	$1,375,403	189,613,000	$0.00725
	FDD - Storage Cycle	Annual	771,074	5	$0.3567	$1,375,210	189,613,000	$0.00725
	FDD - Reservation	Annual	5,035	12	$3.3157	$200,335	189,613,000	$0.00106
	FDD - Storage Cycle	Annual	58,067	5	$0.6901	$200,360	189,613,000	$0.00106
	FDD - Reservation	Annual	4,722	12	$1.7140	$97,122	189,613,000	$0.00051
	FDD - Storage Cycle	Annual	54,437	5	$0.3567	$97,088	189,613,000	$0.00051
	Option	Winter	26,375	3	$4.3463	$343,897	189,613,000	$0.00181
	Exchange	Annual	0	1	$2.0035	$0	189,613,000	$0.00000
	Windom	Annual	2,500	12	$0.0000	$0	189,613,000	$0.00000
	Total Demand Cost					**$20,031,460**	189,613,000	**$0.10564**

GS-1 Demand Current Cost of Gas/therm	**$0.10564**
GS-1 Commodity Current Cost of Gas/therm	**$0.50074**
Total GS-1 Current Cost of Gas/therm	**$0.60638**

B. GS-1, SVI, LVI, SJ-1, LJ-1, SLV-Commodity

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	20,942,963	x	$4.9935	$104,578,686	209,429,630	$0.49935
Call Option Premium				$ 290,827.87	209,429,630	$0.00139
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$104,869,514	209,429,630	**$0.50074**

CURRENT FIRM TRANSPORTATION COST OF GAS (therm) $1.07340

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C, Page 1 of 1) $0.93592

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

November 1, 2009

NNG

COSTS ASSIGNED IN JOINT RATE:	Units	Month	Cost/Unit		Cost	$/Ccf
TF12-B (Max Rate)	30,021	12	$7.5776	=	$2,729,840	$0.12977
TF12-V (Max Rate)	24,583	12	$9.0926	=	$2,682,276	$0.12751
TF5 (Max Rate)	29,619	5	$15.1530	=	$2,244,084	$0.10668
TF12B (Discount-Winter)	5,200	12	$6.4838	=	$404,591	$0.01923
TF5 (Discount-Winter)	0	5	$7.6050	=	$0	$0.00000
TFX5 (Discount)	6,000	5	$4.5600	=	$136,800	$0.00650
TFX12 (Max Rate)	9,724	12	$9.6288	=	$1,123,569	$0.05341
TFX Apr (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00054
TFX Oct (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00054
TFX5 (Max Rate)	48,754	5	$15.1530	=	$3,693,847	$0.17560
TFX5 (Discount)	0	5	$13.8736	=	$0	$0.00000
TFX5 (Discount)	1,800	5	$7.6050	=	$68,445	$0.00325
TFX12 (Discount)	414	12	$4.8667	=	$24,178	$0.00115
TFX12 (Discount)	9,140	12	$5.4570	=	$598,524	$0.02845
TFX7 (Discount)	11,921	12	$2.2204	=	$317,633	$0.01510
TFX5 (Discount)	122	5	$4.8667	=	$2,969	$0.00014
TFX5 (Discount)	2,702	5	$5.4570	=	$73,724	$0.00350
TFX5 (Discount)	22,189	5	$15.1475	=	$1,680,539	$0.07989
FDD - Storage Cycle	58,067	5	$0.6901	=	$200,360	$0.00952
FDD - Storage Cycle	54,437	5	$0.3567	=	$97,088	$0.00462
SMS	20,577	12	$2.1800	=	$538,294	$0.02559
FDD - Storage Cycle	771,074	5	$0.3567	=	$1,375,210	$0.06538
FDD - Reservation	5,035	12	$3.3157	=	$200,335	$0.00952
FDD - Reservation	4,722	12	$1.7140	=	$97,122	$0.00462
FDD - Reservation	66,871	12	$1.7140	=	$1,375,403	$0.06539
			TOTAL		$19,687,563	
			Annualized Entitlement		21,035,410	
			Demand Component		$0.93592	$0.93592

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

NOVEMBER 1, 2009

NNG

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-07- Oct .07	Last Demand Change G011- M-08- Oct. 08	Most Recent PGA Oct. 2009	Current Proposal Effective Nov.1,2009	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:		**125**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	($3.5343)	($0.8121)	38.16%	$1.4272
Demand Cost	$1.1197	$1.1741	$1.0903	$1.0883	$0.8800	($0.2397)	($0.2103)	-19.14%	($0.2083)
Commodity Margin	$1.6263	$1.1771	$1.6263	$1.6263	$1.6263	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$11.4474	$9.2194	$8.6958	$6.4545	$7.6734	($3.7740)	($1.0224)	18.88%	$1.2189
Avg Annual Cost	$1,429.40	$1,151.20	$1,085.82	$805.96	$958.16	($471.25)	($127.66)	18.88%	$152.2006
Effect of proposed commodity change on average annual bills:									$178.21
Effect of proposed demand change on average annual bills:									($26.01)
2) Small Vol. Interruptible: Avg. Annual Use:		**4,080**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	($3.5343)	($0.8121)	38.16%	$1.4272
Demand Cost									
Commodity Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.7682	$7.2226	$4.9833	$6.4105	($3.5343)	($0.8121)	28.64%	$1.4272
Avg Annual Cost	$40,572.00	$31,692.08	$29,466.19	$20,330.47	$26,153.05	($14,418.95)	($3,313.14)	28.64%	$5,822.5764
Effect of proposed commodity change on average annual bills:									$5,822.58
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**19,053**		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	($3.5343)	($0.8121)	38.16%	$1.4272
Demand Cost									
Commodity Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.0606	$7.1282	$6.3384	$4.0991	$5.5263	($3.5343)	($0.8121)	34.82%	$1.4272
Avg Annual Cost	$172,633.79	$135,815.31	$120,767.06	$78,101.14	$105,293.92	($67,339.87)	($15,473.14)	34.82%	$27,192.7841
Effect of proposed commodity change on average annual bills:									$27,192.78
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,080**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	($3.5343)	($0.8121)	38.16%	$1.4272
Demand Cost	$13.4177	$13.1430	$12.0195	$10.3925	$10.6047	($2.8130)	($1.4148)	2.04%	$0.2122
Commodity Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.0724	$1.5000	$2.0724	$2.0724	$2.0724	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.7682	$7.2226	$4.9833	$6.4105	($3.5343)	($0.8121)	28.64%	$1.4272
Total Demand Cost	$15.4901	$14.6430	$14.0919	$12.4649	$12.6771	($2.8130)	($1.4148)	1.70%	$0.2122
Avg Annual Cost	$40,959.25	$32,058.16	$29,818.48	$20,642.09	$26,469.97	($14,489.28)	($3,348.51)	28.23%	$5,827.8811
Effect of proposed commodity change on average annual bills:									$5,822.58
Effect of proposed demand change on average annual bills:									$5.30
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	($3.5343)	($0.8121)	38.16%	$1.4272
Demand Cost	$13.4177	$13.1430	$12.0195	$10.3925	$10.6047	($2.8130)	($1.4148)	2.04%	$0.2122
Commodity Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$0.1658	$1.2000	$1.6579	$1.6579	$1.6579	$1.4921	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.0606	$7.1282	$6.3384	$4.0991	$5.5263	($3.5343)	($0.8121)	34.82%	$1.4272
Total Demand Cost	$13.5835	$14.3430	$13.6774	$12.0504	$12.2626	($1.3209)	($1.4148)	1.76%	$0.2122
Avg Annual Cost	$135,487.13	$106,865.34	$95,094.00	$61,738.52	$82,935.51	($14,451.98)	($12,158.49)	34.33%	$21,196.9892
Effect of proposed commodity change on average annual bills:									$21,181.08
Effect of proposed demand change on average annual bills:									$15.91

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-09-896

*Implemented with Interim rates

**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs

November 1, 2009

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-09**

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$7.5776	$15.1530	$10.7340	$0.0000	$10.7340
TF-12V	$9.0926	$6.4838	$8.0056	$0.0000	$8.0056
TF-5		$7.6050	$7.6050	$0.0000	$7.6050
TFX	$4.5600	$9.6288	$6.6720	$0.0000	$6.6720
FIELD TF			$0.0000	$0.0000	$0.0000
Commodity From Schedule D					$4.9935

V. ANNUAL SALES -- As filed in Docket No. G007,011/MR-08-836

Total Northern Annual Sales 209,429,630 therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-09**

	Contract Type	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	GS-1 Rate Case Sales (therm)	Rate ($/therm)
A. GS-1	TF12-B (Max Rate)	Annual	30,021	12	$7.5776	$2,729,840	189,613,000	$0.01440
	TF12-V (Max Rate)	Annual	24,583	12	$9.0926	$2,682,276	189,613,000	$0.01415
	TF5 (Max Rate)	Winter	29,619	5	$15.1530	$2,244,084	189,613,000	$0.01184
	TF12B (Discount-Winter	Winter	5,200	12	$6.4838	$404,591	189,613,000	$0.00213
	TF5 (Discount-Winter)	Winter	0	5	$7.6050	$0	189,613,000	$0.00000
	TFX5 (Discount)	Winter	6,000	5	$4.5600	$136,800	189,613,000	$0.00072
	TFX12 (Max Rate)	Annual	9,724	12	$9.6288	$1,123,569	189,613,000	$0.00593
	TFX Apr (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX Oct (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX5 (Max Rate)	Winter	48,754	5	$15.1530	$3,693,847	189,613,000	$0.01948
	TFX5 (Discount)	Winter	0	5	$13.8736	$0	189,613,000	$0.00000
	TFX5 (Discount)	Winter	1,800	5	$7.6050	$68,445	189,613,000	$0.00036
	TFX12 (Discount)	Annual	414	12	$4.8667	$24,178	189,613,000	$0.00013
	TFX12 (Discount)	Annual	9,140	12	$5.4570	$598,524	189,613,000	$0.00316
	TFX7 (Discount)	Summer	11,921	12	$2.2204	$317,633	189,613,000	$0.00168
	TFX5 (Discount)	Winter	122	5	$4.8667	$2,969	189,613,000	$0.00002
	TFX5 (Discount)	Winter	2,702	5	$5.4570	$73,724	189,613,000	$0.00039
	TFX5 (Discount)	Winter	22,189	5	$15.1475	$1,680,539	189,613,000	$0.00886
	SMS	Annual	20,577	12	$2.1800	$538,294	189,613,000	$0.00284
	Option	Winter	26,375	3	$4.3463	$343,897	189,613,000	$0.00181
	Exchange	Annual	0	1	$2.0035	$0	189,613,000	$0.00000
	Windom	Annual	2,500	12	$0.0000	$0	189,613,000	$0.00000
	Total Demand Cost					**$16,685,942**	189,613,000	**$0.08800**

GS-1 Demand Current Cost of Gas/therm	**$0.08800**
GS-1 Commodity Current Cost of Gas/therm	**0.51671**
Total GS-1 Current Cost of Gas/therm	**$0.60471**

B. GS-1, SVI, LVI, SJ-1, LJ-1, SLV-Commodity

	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Annual Rate Case Sales (therm)	Rate ($/therm)
FDD - Reservation	Annual	66,871	12	$1.7140	$1,375,403	209,429,630	$0.00657
FDD - Storage Cycle	Annual	771,074	5	$0.3567	$1,375,210	209,429,630	$0.00657
FDD - Reservation	Annual	5,035	12	$3.3157	$200,335	209,429,630	$0.00096
FDD - Storage Cycle	Annual	58,067	5	$0.6901	$200,360	209,429,630	$0.00096
FDD - Reservation	Annual	4,722	12	$1.7140	$97,122	209,429,630	$0.00046
FDD - Storage Cycle	Annual	54,437	5	$0.3567	$97,088	209,429,630	$0.00046
Firm Deferred Delivery Storage Contracts					$3,345,518	209,429,630	$0.01597
Call Option Premium					$ 290,827.87	209,429,630	$0.00139

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	20,942,963	x	$4.9935	$104,578,686	209,429,630	$0.49935
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$108,215,032	209,429,630	**$0.51671**

CURRENT FIRM TRANSPORTATION COST OF GAS (therm) $1.07340

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C, Page 1 of 1) $1.06047

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs

November 1, 2009

NNG

COSTS ASSIGNED IN JOINT RATE:	Units	Month	Cost/Unit		Cost	$/Ccf
TF12-B (Max Rate)	30,021	12	$7.5776	=	$2,729,840	$0.17714
TF12-V (Max Rate)	24,583	12	$9.0926	=	$2,682,276	$0.17406
TF5 (Max Rate)	29,619	5	$15.1530	=	$2,244,084	$0.14562
TF12B (Discount-Winter)	5,200	12	$6.4838	=	$404,591	$0.02625
TF5 (Discount-Winter)	0	5	$7.6050	=	$0	$0.00000
TFX5 (Discount)	6,000	5	$4.5600	=	$136,800	$0.00888
TFX12 (Max Rate)	9,724	12	$9.6288	=	$1,123,569	$0.07291
TFX Apr (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00074
TFX Oct (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00074
TFX5 (Max Rate)	48,754	5	$15.1530	=	$3,693,847	$0.23970
TFX5 (Discount)	0	5	$13.8736	=	$0	$0.00000
TFX5 (Discount)	1,800	5	$7.6050	=	$68,445	$0.00444
TFX12 (Discount)	414	12	$4.8667	=	$24,178	$0.00157
TFX12 (Discount)	9,140	12	$5.4570	=	$598,524	$0.03884
TFX7 (Discount)	11,921	12	$2.2204	=	$317,633	$0.02061
TFX5 (Discount)	122	5	$4.8667	=	$2,969	$0.00019
TFX5 (Discount)	2,702	5	$5.4570	=	$73,724	$0.00478
TFX5 (Discount)	22,189	5	$15.1475	=	$1,680,539	$0.10905
SMS	20,577	12	$2.1800	=	$538,294	$0.03493
FDD - Reservation	66,871	0	$0.0000	=	$0	$0.00000
FDD - Storage Cycle	771,074	0	$0.0000	=	$0	$0.00000
FDD - Reservation	5,035	0	$0.0000	=	$0	$0.00000
FDD - Storage Cycle	58,067	0	$0.0000	=	$0	$0.00000
FDD - Reservation	4,722	0	$0.0000	=	$0	$0.00000
FDD - Storage Cycle	54,437	0	$0.0000	=	$0	$0.00000
			TOTAL		$16,342,045	
			Annualized Entitlement		15,410,210	
			Demand Component		$1.06047	$1.06047

MINNESOTA ENERGY RESOURCES

NNG Entitlement Allocation

Heating Season 2009-2010

0

		Total Entitlement Levels	PNG GS	NMU GS	Total
1	Design Day	**228,040**	203,360	24,680	**228,040**
2	Customer Requirements moving to Transport	**-**	-	-	**-**
3	Adjusted Design Day	**228,040**	203,360	24,680	228,040
5	Total Design Day Capacity	**261,675**	238,064	23,611	**261,675**
6	Less: Windom	(2,500)	(2,500)		**(2,500)**
7	Less: LS Power	(29,100)	(26,375)	(2,725)	**(29,100)**
8	Less: Chisago Delivery to Viking	(7,000)	(7,000)		**(7,000)**
9	Less: Contract Demand Units	0	0		-
		223,075	202,189	20,886	**223,075**
	Direct Assigned Entitlement				
10	TF12B (112495)	42,734	35,221	7,513	**42,734**
11	TF12V (112495)	29,826	24,583	5,243	**29,826**
12	TF5 (112495)	31,610	29,619	1,991	**31,610**
13	TFX12 (112486)	9,724	9,724	0	**9,724**
14	TFX April Only (112486)	2,000	2,000	0	**2,000**
15	TFX October Only (112486)	2,000	2,000	0	**2,000**
16	TFX5 (112486)	56,693	50,554	6,139	**56,693**
17	TFX12 (111866)	21,475	21,475	0	**21,475**
18	TFX5 (111866)	25,013	25,013	0	**25,013**
19	TFX5 (112561)	6,000	6,000	0	**6,000**
20	Total Winter Allocated Entitlement	223,075	202,189	20,886	**223,075**
21	Windom	2,500	2,500	0	**2,500**
22	LS Power	29,100	26,375	2,725	**29,100**
23	Total Design Day Capacity	**254,675**	**231,064**	**23,611**	254,675
24	Contract Demand				**-**
25	Total Design Day Capacity	**254,675**	231,064	23,611	**254,675**
			90.73%	9.27%	**100.00%**
	Other Entitlements not included in Peak Day Deliverability: allocation based on design day % on line 19				
26	Storage				
27	Storage MSQ - 118657	4,569,321	4,145,706	423,615	**4,569,321**
28	Storage MSQ - 119884	300,000	272,187	27,813	**300,000**
29	SMS	22,680	20,577	2,103	**22,680**
30	Total Entitlement	254,675	231,064	23,611	**254,675**
31	Design Day	228,040	203,360	24,680	**228,040**
32	Reserve Margin *	26,635	27,704	(1,069)	**26,635**
Note:		11.68%	13.62%	-4.33%	11.68%

MINNESOTA ENERGY RESOURCES - PNG

CALCULATION OF DESIGN DAY REQUIREMENTS

NNG

2009-2010

State	1/20 Design DDD	08/09 Customer Counts*	Regression Factors Intercept	Slope	Regression Total	Adjustment Total *	1/20 Requirements Regression Load	Nov09-Mar10 Customer Growth	Total
MERC - Peak Day									
PNG	99	157,670	30,580	2,337	263,960	57,265	206,695	-1.60%	203,360
NMU	103	17,558	2,462	238	26,962	2,641	24,321	1.50%	24,680
TOTAL		**175,228**	**33,042**	**2,575**	**290,922**	**59,906**	**231,016**		**228,040**

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2009-2010 VS. 2008-2009

Attachment 7

	2009-2010 Proposed				2008-2009				Difference			
	NNG Winter	NNG PNG	NNG NMU	NNG Total	NNG Winter	NNG PNG	NNG NMU	NNG Total	Winter	PNG	NMU	Total
TF12(base)	42,734	35,221	7,513	42,734	32,559	29,906	2,653	32,559	10,175	5,315	4,860	10,175
TF12(variable)	29,826	24,583	5,243	29,826	39,333	32,690	6,643	39,333	(9,507)	(8,107)	(1,400)	(9,507)
TF12	72,560	59,804	12,756	72,560	71,892	62,596	9,296	71,892	668	(2,792)	3,460	668
Peak Capacity	-			-	-			-	-			-
TF5	31,610	29,619	1,991	31,610	32,278	26,827	5,451	32,278	(668)	2,792	(3,460)	(668)
TF Total	104,170	89,423	14,747	104,170	104,170	89,423	14,747	104,170	-	-	-	-
TFX12	31,199	31,199	-	31,199	29,246	29,246	-	29,246	1,953	1,953	-	1,953
TFX5	87,706	81,567	6,139	87,706	85,432	79,293	6,139	85,432	2,274	2,274	-	2,274
TFX Total	118,905	112,766	6,139	118,905	114,678	108,539	6,139	114,678	4,227	4,227	-	4,227
NNG Total	223,075	202,189	20,886	223,075	218,848	197,962	20,886	218,848	4,227	4,227	-	4,227
Windom	2,500	2,500	-	2,500	2,500	2,500	-	2,500	-	-	-	-
LSP Peaking	29,100	26,375	2,725	29,100	29,100	26,323	2,777	29,100	-	52	(52)	0
									-			
Total	254,675	231,064	23,611	254,675	250,448	226,785	23,663	250,448	4,227	4,279	(52)	4,227

NNG-Total	EF	TOTAL
Design Day	228,040	228,040
Capacity	254,675	254,675
Reserve Margin	26,635	26,635
	11.68%	11.68%

NNG-PNG	EF	TOTAL
Design Day	203,360	203,360
Capacity	231,064	231,064
Reserve Margin	27,704	27,704
	13.62%	13.62%

NNG-NMU	EF	TOTAL
Design Day	24,680	24,680
Capacity	23,611	23,611
Reserve Margin	(1,069)	(1,069)
	-4.33%	-4.33%

MINNESOTA ENERGY RESOURCES - NNG

Financial Options

Heating Season 2009-2010

[TRADE SECRET DATA BEGINS

Units - Gas Daily Packages

No Gas Daily Peakers were purchased

Units - Call Option (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
Total		24,000		33,226		36,129		33,929		25,484	152,767	4,610,000

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
Total	**0.4039**	**$ 290,813**	**0.5838**	**$ 601,322**	**0.5671**	**$ 635,149**	**0.6151**	**$ 584,318**	**0.71**	**$ 560,867**	**0.5797**	**$ 2,672,469**

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

*****PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED*****

09/10 Winter Portfolio Plan - MERC NNG-PNG Hedging Plan

[TRADE SECRET DATA BEGINS

10,000 Contract Size

		Nov-09		Dec-09		Jan-10		Feb-10		Mar-10		Total		Percent
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	of Requirements
Total													15,272,339	**100.00%**

TRADE SECRET DATA ENDS]

*****PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED*****

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (PNG)

NOVEMBER, 2009 THROUGH MARCH, 2010

[TRADE SECRET DATA BEGINS

PHYSICAL FIXED PRICE HEDGES	Trigger	Trigger	Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total
Total Actual Fixed/Option Physical			17,669	9,356	13,227	6,431	20,006	2,030,391

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Total Actual Seasonal Index				24,000	32,904	36,131	33,929	25,485	4,600,118

GAS DAILY PACKAGES

NO Gas Daily Peakers

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 119884 Volume Injected	Total Volume Injected
	3,948,666	272,187	4,220,854

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

MINNESOTA ENERGY RESOURCES - PNG

Attachment 10						
NNG				**G011/**		
As Proposed	M-05-1728	M-06-1536	M-07-1405	**M-08-1331**	**M-09-**	
08-	Peoples Mn GS	Peoples Mn GS	Peoples Mn GS	**Peoples Mn GS**	**Peoples Mn GS**	Proposed Change
Design Day	200,421	200,484	202,263	**225,397**	**203,360**	-22,037
Customer Requirements moving to Transportation 2005-6	400					
Adjusted Design Day	200,021					
Design Day Percentages	33.71%	33.79%	32.16%	**30.56%**	**31.50%**	0.94%
Total Design Day Capacity (includes non-recallable capacity)	210,127	227,526	233,785	**233,785**	**238,064**	4,279
Less: Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
Less: LS Power	6,120	29,100	26,323	**26,323**	**26,375**	52
Less: TF12B	5,927	42,170	7,000	**7,000**	**7,000**	0
Less: TF5	2,073	36,772				0
Less: TFX(5)	0	73,190				0
Total Design Day Capacity	193,507	195,926	197,962	**197,962**	**202,189**	4,227
Factors for All Winter Capacity	45.27%	100.00%	100.00%	**100.00%**	**100.00%**	
Allocated Entitlements in PGA						
TF12B	68,765	42,170	43,858	**29,906**	**35,221**	5,315
TF12V	0	34,070	15,946	**32,690**	**24,583**	-8,107
TF5	84,713	36,772	29,619	**26,827**	**29,619**	2,792
TFX12	0	9,724	18,409	**29,246**	**31,199**	1,953
TFX(5)	22,598	73,190	90,130	**79,293**	**81,567**	2,274
TFX(5) (12-V)	6,113	0	0	**0**	**0**	0
LS Power	0	0	26,323	**26,323**	**26,375**	52
Peak Capacity	11,318	0	0			0
Total Allocated Entitlements in PGA	193,507	195,926	224,285	**224,285**	**228,564**	4,279
Direct Assigned Entitlements in PGA						
Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
LS Power	6,120	29,100	26,323	**26,323**	**26,375**	52
TFX (October Only)	0	2,000	2,000	**2,000**	**2,000**	0
TFX (April Only)	0	2,000	2,000	**2,000**	**2,000**	0
TFX(5)	5,927	0	0			0
TFX(7)	2,073	0	0			0
TFX(5)	0	0	0			0
Total Direct Assignments	16,620	35,600	32,823	**32,823**	**32,875**	52
Total Capacity before Peak Shaving	210,127	231,526	257,108	**257,108**	**261,440**	4,332
LP Peak Shaving	0	0	0	**0**	**0**	0
Total Design Day Capacity	210,127	227,526	253,108	**253,108**	**257,440**	4,332
Total Transp. (with TFX Offpeak less LSP)	262,081	198,426	226,785	**226,785**	**231,064**	4,279
Total Annual Transportation	68,765	88,464	80,713	**94,342**	**93,503**	-839
Total Seasonal Transportation	126,815	139,062	172,395	**158,766**	**163,937**	5,171
Total Percent Seasonal	60.4%	61.1%	68.1%	**62.7%**	**63.7%**	0.95%
LS Power as % of Total DD Capacity	2.9%	12.8%	10.4%	**10.4%**	**10.2%**	-0.15%
Reserve Margin	5.05%	13.49%	25.14%	**12.29%**	**26.59%**	14.30%
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	0	0	0			0
Total Design Day Capacity w/ contract demand	210,127	227,526	233,785	**233,785**	**238,064**	4,279
Factors	33.71%	33.79%	32.16%	**30.56%**	**31.50%**	0.94%
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)	20,227	0	0	**0**	**0**	0
TFX Offpeak Old Oct. (35,000)	11,799	0	0	**0**	**0**	0
TFX Offpeak New Oct. (14,600)	4,922	0	0	**0**	**0**	0
TFX Offpeak New Apr. (39,600)	13,350	0	0	**0**	**0**	0
TFX Oct	0	2,000	2,000	**2,000**	**2,000**	0
TFX Apr	0		2,000	**2,000**	**2,000**	0
TFX Apr-Oct	2,855	0	0	**0**	**0**	0
TFX May-Sept	4,922	0	0	**0**	**0**	0
FDD Storage reservation	46,830	69,094	73,022	**76,476**	**76,628**	152
FDD Storage capacity	2,699,984	4,349,321	4,210,037	**4,409,251**	**4,417,893**	8,642
Nexen PSO	85,964	0	0	**0**	**0**	0
Tenaska PSO New	168,558	188,000	170,237	**0**	**0**	0
NGPL	1,199,532	0	0	**0**	**0**	0
SMS	18,204	22,680	20,537	**20,537**	**20,577**	40
SBA	0	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - PNG

Attachment 11
Rate Impacts
NNG

1) General Service: Avg. Annual Use: 125 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	-42.45%	-16.25%	33.89%	$1.2675
Demand Rate	$1.1197	$1.1741	$1.0903	$1.0883	$1.0564	-5.65%	-3.11%	-2.93%	($0.0319)
Margin	$1.6263	$1.1771	$1.6263	$1.6263	$1.6263	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$11.4474	$9.2194	$8.6958	$6.4545	$7.6901	-32.82%	-11.56%	19.14%	$1.2356
Avg. Annual Bill*	$1,429.40	$1,151.20	$1,085.82	$805.96	$960.25	-32.82%	-11.56%	19.14%	$154.2907
Effect of proposed commodity change on average annual bills:									$158.2691
Effect of proposed demand change on average annual bills:									($3.9784)

2) Small Volume Interruptible: Avg. Annual Use: 4,080 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	-42.45%	-16.25%	33.89%	$1.2675
Demand Rate									
Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.9448	$7.7682	$7.2226	$4.9833	$6.2508	-37.15%	-13.45%	25.43%	$1.2675
Avg. Annual Bill*	$40,572.00	$31,692.08	$29,466.19	$20,330.47	$25,501.51	-37.15%	-13.45%	25.43%	$5,171.0451
Effect of proposed commodity change on average annual bills:									$5,171.0451
Effect of proposed demand change on average annual bills:									$0.0000

3) Large Volume Interruptible: Avg. Annual Use: 19,053 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	-42.45%	-16.25%	33.89%	$1.2675
Demand Rate									
Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.0606	$7.1282	$6.3384	$4.0991	$5.3666	-40.77%	-15.33%	30.92%	$1.2675
Avg. Annual Bill*	$172,633.79	$135,815.31	$120,767.06	$78,101.14	$102,251.12	-40.77%	-15.33%	30.92%	$24,149.9817
Effect of proposed commodity change on average annual bills:									$24,149.9817
Effect of proposed demand change on average annual bills:									$0.0000

4) Small Volume Firm: Avg. Annual Use: 4,080 Mcf
Avg. Annual CD Volumes: 25 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	-42.45%	-16.25%	33.89%	$1.2675
Demand Rate	$13.4177	$13.1430	$12.0195	$10.3925	$9.3592	-30.25%	-22.13%	-9.94%	($1.0333)
Comm. Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$1.5000	$2.0724	$2.0724	$2.0724	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.9448	$7.7682	$7.2226	$4.9833	$6.2508	-37.15%	-13.45%	25.43%	$1.2675
Total Demand Cost	$15.4901	$14.6430	$14.0919	$12.4649	$11.4316	-26.20%	-18.88%	-8.29%	($1.0333)
Avg. Annual Bill*	$40,959.25	$32,058.16	$29,818.48	$20,642.09	$25,787.30	-37.04%	-13.52%	24.93%	$5,145.2138
Effect of proposed commodity change on average annual bills:									$5,171.0451
Effect of proposed demand change on average annual bills:									($25.8313)

5) Large Volume Firm: Avg. Annual Use: 14,841 Mcf
Avg. Annual CD Units: 75 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.0074	-42.45%	-16.25%	33.89%	$1.2675
Demand Rate	$13.4177	$13.1430	$12.0195	$10.3925	$9.3592	-30.25%	-22.13%	-9.94%	($1.0333)
Comm. Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$0.1658	$1.2000	$1.6579	$1.6579	$1.6579	900.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.0606	$7.1282	$6.3384	$4.0991	$5.3666	-40.77%	-15.33%	30.92%	$1.2675
Total Demand Cost	$13.5835	$14.3430	$13.6774	$12.0504	$11.0171	-18.89%	-19.45%	-8.57%	($1.0333)
Avg. Annual Bill*	$135,487.13	$106,865.34	$95,094.00	$61,738.52	$80,472.00	-40.61%	-15.38%	30.34%	$18,733.4736
Effect of proposed commodity change on average annual bills:									$18,810.9675

MINNESOTA ENERGY RESOURCES - PNG

Attachment 11

Rate Impacts (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)
NNG

1) General Service: Avg. Annual Use: 125 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	-40.62%	-13.58%	38.16%	$1.4272
Demand Rate	$1.1197	$1.1741	$1.0903	$1.0883	$0.8800	-21.41%	-19.29%	-19.14%	($0.2083)
Margin	$1.6263	$1.1771	$1.6263	$1.6263	$1.6263	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$11.4474	$9.2194	$8.6958	$6.4545	$7.6734	-32.97%	-11.76%	18.88%	$1.2189
Avg. Annual Bill*	$1,429.40	$1,151.20	$1,085.82	$805.96	$958.16	-32.97%	-11.76%	18.88%	$152.2006
Effect of proposed commodity change on average annual bills:									$178.2104
Effect of proposed demand change on average annual bills:									($26.0098)

2) Small Volume Interruptible: Avg. Annual Use: 4,080 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	-40.62%	-13.58%	38.16%	$1.4272
Demand Rate									
Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.9448	$7.7682	$7.2226	$4.9833	$6.4105	-35.54%	-11.24%	28.64%	$1.4272
Avg. Annual Bill*	$40,572.00	$31,692.08	$29,466.19	$20,330.47	$26,153.05	-35.54%	-11.24%	28.64%	$5,822.5764
Effect of proposed commodity change on average annual bills:									$5,822.5764
Effect of proposed demand change on average annual bills:									$0.0000

3) Large Volume Interruptible: Avg. Annual Use: 19,053 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	-40.62%	-13.58%	38.16%	$1.4272
Demand Rate									
Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.0606	$7.1282	$6.3384	$4.0991	$5.5263	-39.01%	-12.81%	34.82%	$1.4272
Avg. Annual Bill*	$172,633.79	$135,815.31	$120,767.06	$78,101.14	$105,293.92	-39.01%	-12.81%	34.82%	$27,192.7841
Effect of proposed commodity change on average annual bills:									$27,192.7841
Effect of proposed demand change on average annual bills:									$0.0000

4) Small Volume Firm: Avg. Annual Use: 4,080 Mcf
Avg. Annual CD Volumes: 25 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	-40.62%	-13.58%	38.16%	$1.4272
Demand Rate	$13.4177	$13.1430	$12.0195	$10.3925	$10.6047	-20.96%	-11.77%	2.04%	$0.2122
Comm. Margin	$1.2434	$0.9000	$1.2434	$1.2434	$1.2434	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$1.5000	$2.0724	$2.0724	$2.0724	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.9448	$7.7682	$7.2226	$4.9833	$6.4105	-35.54%	-11.24%	28.64%	$1.4272
Total Demand Cost	$15.4901	$14.6430	$14.0919	$12.4649	$12.6771	-18.16%	-10.04%	1.70%	$0.2122
Avg. Annual Bill*	$40,959.25	$32,058.16	$29,818.48	$20,642.09	$26,469.97	-35.37%	-11.23%	28.23%	$5,827.8811
Effect of proposed commodity change on average annual bills:									$5,822.5764
Effect of proposed demand change on average annual bills:									$5.3047

5) Large Volume Firm: Avg. Annual Use: 14,841 Mcf
Avg. Annual CD Units: 75 Mcf

Recovery	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$6.8682	$5.9792	$3.7399	$5.1671	-40.62%	-13.58%	38.16%	$1.4272
Demand Rate	$13.4177	$13.1430	$12.0195	$10.3925	$10.6047	-20.96%	-11.77%	2.04%	$0.2122
Comm. Margin	$0.3592	$0.2600	$0.3592	$0.3592	$0.3592	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$0.1658	$1.2000	$1.6579	$1.6579	$1.6579	900.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.0606	$7.1282	$6.3384	$4.0991	$5.5263	-39.01%	-12.81%	34.82%	$1.4272
Total Demand Cost	$13.5835	$14.3430	$13.6774	$12.0504	$12.2626	-9.72%	-10.34%	1.76%	$0.2122
Avg. Annual Bill*	$135,487.13	$106,865.34	$95,094.00	$61,738.52	$82,935.51	-38.79%	-12.79%	34.33%	$21,196.9892

MINNESOTA ENERGY RESOURCES - PNG

Attachment 12
Change in Costs due to November 1, 2006 Change in Entitlement Levels and Related Demand Costs
NNG

	Contract	Oct-09 PGA	Nov-09 Entitlement	Entitlement Change	Months	Oct-09 Rate/MCF	Oct-09 Total Cost	Entitlement Total Cost	Entitlement Change
TF-12-B (Max Rate)	112495	25,469	30,021	4,552	12	$ 7.5776	$2,315,922	$2,729,840	$413,918
TF-12-B (Discount)	112495	4,437	5,200	763	12	$ 6.4838	$345,225	$404,591	$59,366
TF-12-V (Max Rate)	112495	32,690	24,583	(8,107)	12	$ 9.0926	$3,566,839	$2,682,276	($884,563)
TF-5 (Max Rate)	112495	26,064	29,619	3,555	5	$ 15.1530	$1,974,739	$2,244,084	$269,345
TF-5 (Discount)	112495	763	0	(763)	5	$ 7.6050	$29,013	$0	($29,013)
TFX-12 (Max Rate)	112486	9,724	9,724	0	12	$ 9.6288	$1,123,569	$1,123,569	$0
TFX-12 (Discount)	111866	414	414	0	12	$ 4.8667	$24,178	$24,178	$0
TFX-12 (Discount)	111866	8,271	9,140	869	12	$ 5.4570	$541,618	$598,524	$56,906
TFX-12 (Discount)	111866	0	11,921	11,921	12	$ 2.2204	$0	$317,633	$317,633
TFX-5 (Max Rate)	112486	46,558	48,754	2,196	5	$ 15.1530	$3,527,467	$3,693,847	$166,380
TFX-5 (Discount)	112486	2,196	0	(2,196)	5	$ 13.8736	$152,332	$0	($152,332)
TFX-5 (Discount)	112486	1,800	1,800	0	5	$ 7.6050	$68,445	$68,445	$0
TFX-5 (Discount)	111866	122	122	0	5	$ 4.8667	$2,969	$2,969	$0
TFX-5 (Discount)	111866	2,445	2,702	257	5	$ 5.4570	$66,712	$73,724	$7,012
TFX-5 (Discount)	111866	31,009	22,189	(8,820)	5	$ 15.1475	$2,348,544	$1,680,539	($668,005)
TFX-5 (Discount)	112561	6,000	6,000	0	5	$ 4.5600	$136,800	$136,800	$0
TFX-7 (Discount)	111866	10,837	0	(10,837)	7	$ 2.2204	$168,437	$0	($168,437)
TFX Oct (Max Rate)	112486	2,000	2,000	0	1	$ 5.6830	$11,366	$11,366	$0
TFX Apr (Max Rate)	112486	2,000	2,000	0	1	$ 5.6830	$11,366	$11,366	$0
SMS Charge		20,537	20,577	40	12	$ 2.1800	$537,248	$538,294	$1,046
LS Power		26,323	26,375	52	3	$ 4.3463	$343,219	$343,897	$678
WINDOM		2,500	2,500	0	12	$ -	$0	$0	$0
FDD: Storage Reservation		71,451	71,593	142	12	$ 1.7140	$1,469,598	$1,472,525	$2,927
FDD: Storage Reservation		5,026	5,035	9	12	$ 3.3157	$199,961	$200,335	$373
FDD: Storage Cycle Volume		823,897	825,511	1,614	5	$ 0.3567	$1,469,420	$1,472,299	$2,879
FDD: Storage Cycle Volume		57,953	58,067	114	5	$ 0.6901	$199,967	$200,360	$393
Total Demand Cost							$20,634,954	$20,031,459	($603,495)

Costs Assigned In Commodity:	Oct-09	Nov-09	Entitlement		Oct-09	Oct-09	Entitlement	Entitlement
Upstream	PGA	Entitlement	Change	Months	Rate/MCF	Total Cost	Total Cost	Change
Great Lakes	0	0	0	12	$3.458	$0	$0	$0
			0				$0	$0
Surcharges:			0				$0	$0
			0				$0	$0
Storage			0				$0	$0
FDD Withdrawal	4,409,251	4,417,893	8,642	1	$0.0149	$65,698	$65,827	$129
FDD Injection	4,409,251	4,417,893	8,642	1	$0.0149	$65,698	$65,827	$129
							$0	$0
							$0	$0
Producer Demand Payments/Option Premium						$5,216,072	$2,672,469	($2,543,603)
Total Commodity Costs						$5,347,468	$2,804,122	($2,543,346)

MINNESOTA ENERGY RESOURCES - PNG

Attachment 13
Daily Total Throughput Data - July 1, 2008 through June 30, 2009
NNG

Base	30,318
Variable	2,189

Date	3.27% Cloquet Adjusted HDD	32.62% Minneapolis Adjusted HDD	64.11% Rochester Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/08	0	0	0	0	34,935	30,318
7/2/08	1	0	0	0	34,257	30,398
7/3/08	8	0	1	1	28,697	32,401
7/4/08	7	0	0	0	23,846	30,839
7/5/08	0	0	0	0	24,611	30,318
7/6/08	0	0	0	0	32,133	30,318
7/7/08	8	0	0	0	40,292	30,859
7/8/08	7	0	0	0	35,716	30,790
7/9/08	2	0	0	0	34,150	30,473
7/10/08	5	0	0	0	32,978	30,690
7/11/08	11	0	0	0	39,410	31,105
7/12/08	2	0	0	0	35,289	30,483
7/13/08	2	0	0	0	38,234	30,484
7/14/08	2	0	0	0	39,520	30,468
7/15/08	0	0	0	0	42,745	30,318
7/16/08	1	0	0	0	50,027	30,392
7/17/08	6	0	0	0	45,943	30,760
7/18/08	0	0	0	0	36,002	30,318
7/19/08	9	0	0	0	33,336	30,931
7/20/08	2	0	0	0	38,130	30,464
7/21/08	4	0	0	0	43,781	30,619
7/22/08	3	0	0	0	40,040	30,546
7/23/08	7	0	0	0	40,199	30,839
7/24/08	0	0	0	0	40,566	30,318
7/25/08	0	0	0	0	42,199	30,318
7/26/08	0	0	0	0	33,902	30,318
7/27/08	0	0	0	0	36,084	30,318
7/28/08	0	0	0	0	43,742	30,318
7/29/08	0	0	0	0	50,238	30,318
7/30/08	0	0	0	0	41,842	30,318
7/31/08	1	0	0	0	40,676	30,391
8/1/08	0	0	0	0	47,772	30,318
8/2/08	2	0	0	0	42,135	30,467
8/3/08	2	0	0	0	45,712	30,467
8/4/08	0	0	0	0	55,311	30,318
8/5/08	0	0	0	0	49,059	30,318
8/6/08	1	0	0	0	47,091	30,395
8/7/08	2	0	0	0	46,384	30,470
8/8/08	3	0	0	0	43,521	30,541
8/9/08	4	0	0	0	39,671	30,627
8/10/08	10	0	2	2	44,787	34,002
8/11/08	3	0	2	1	47,869	33,545
8/12/08	4	0	0	0	47,794	30,616
8/13/08	0	0	0	0	48,357	30,318
8/14/08	1	0	0	0	47,443	30,396
8/15/08	6	0	0	0	45,538	30,756
8/16/08	0	0	0	0	44,185	30,318
8/17/08	0	0	0	0	44,783	30,318
8/18/08	0	0	0	0	52,877	30,318

9/26/08	0	0	0	0	43,302	30,318
9/27/08	13	0	0	0	39,366	31,220
9/28/08	17	8	3	5	46,388	41,996
9/29/08	16	9	6	7	53,230	45,469
9/30/08	21	15	13	14	55,665	61,208
10/1/08	19	16	19	18	59,342	69,376
10/2/08	17	12	15	14	57,796	61,167
10/3/08	25	16	16	16	60,731	65,647
10/4/08	23	14	17	16	53,877	65,955
10/5/08	21	13	10	11	55,676	55,013
10/6/08	16	3	2	3	56,457	37,102
10/7/08	16	11	11	11	62,057	54,957
10/8/08	15	8	10	9	60,544	51,086
10/9/08	19	14	17	16	66,241	66,142
10/10/08	24	7	8	8	55,308	47,664
10/11/08	15	0	2	2	48,952	34,442
10/12/08	13	0	0	0	47,930	31,220
10/13/08	14	8	9	9	66,104	49,395
10/14/08	22	20	18	19	71,509	71,970
10/15/08	24	19	19	19	77,241	71,889
10/16/08	26	20	22	22	76,325	77,690
10/17/08	25	19	21	20	79,301	74,273
10/18/08	25	19	23	22	70,328	77,972
10/19/08	17	10	10	10	62,080	52,630
10/20/08	31	19	20	20	85,655	73,831
10/21/08	29	25	25	25	90,892	85,019
10/22/08	29	24	24	24	95,159	83,052
10/23/08	24	19	19	19	82,147	72,436
10/24/08	24	18	22	21	80,814	75,570
10/25/08	21	14	18	17	73,700	67,028
10/26/08	28	28	29	28	103,325	92,600
10/27/08	37	34	36	35	124,802	107,014
10/28/08	32	28	31	30	112,954	96,791
10/29/08	29	24	22	23	96,492	80,263
10/30/08	14	10	12	12	76,435	55,717
10/31/08	25	14	11	12	82,295	57,168
11/1/08	25	20	17	18	76,998	69,544
11/2/08	20	7	3	5	61,688	41,767
11/3/08	16	2	0	1	62,020	33,052
11/4/08	7	2	2	2	58,336	35,719
11/5/08	12	7	7	7	60,968	45,594
11/6/08	20	23	23	23	77,360	80,120
11/7/08	32	32	34	33	96,607	102,572
11/8/08	46	40	39	40	107,789	117,729
11/9/08	46	43	46	45	124,008	128,766
11/10/08	45	38	39	39	128,275	115,264
11/11/08	37	36	37	36	117,098	110,038
11/12/08	35	30	31	31	102,845	97,462
11/13/08	31	29	29	29	94,618	93,075
11/14/08	37	34	34	34	107,890	104,744
11/15/08	44	37	41	40	118,102	117,315
11/16/08	45	41	39	39	119,167	116,656
11/17/08	50	45	47	47	145,775	132,208
11/18/08	46	42	45	44	138,782	127,249
11/19/08	50	41	40	41	134,787	119,679
11/20/08	61	53	55	54	158,336	149,029
11/21/08	54	49	51	50	145,313	140,308
11/22/08	46	40	43	42	120,400	123,175
11/23/08	43	35	36	36	110,930	108,451
11/24/08	51	43	44	44	129,298	125,911
11/25/08	50	41	41	42	133,404	121,365
11/26/08	44	36	36	37	116.064	110.534

1/3/09	59	59	59	59	149,449	158,634
1/4/09	80	71	69	70	183,228	183,199
1/5/09	70	56	53	54	159,896	149,324
1/6/09	54	52	53	53	152,268	146,398
1/7/09	69	65	71	69	187,422	182,109
1/8/09	71	63	63	63	168,324	167,969
1/9/09	67	59	59	60	162,948	160,801
1/10/09	61	56	59	58	153,903	157,357
1/11/09	64	58	60	59	161,542	160,302
1/12/09	81	75	75	75	191,552	194,757
1/13/09	83	82	82	82	208,891	209,608
1/14/09	90	85	90	89	227,256	224,761
1/15/09	85	83	89	87	233,483	220,696
1/16/09	80	72	75	74	192,043	192,201
1/17/09	66	53	57	56	156,462	152,771
1/18/09	56	51	56	54	151,802	148,684
1/19/09	58	54	58	57	160,520	154,122
1/20/09	57	53	57	55	151,792	151,803
1/21/09	53	47	56	53	146,301	146,030
1/22/09	54	47	52	51	141,026	140,915
1/23/09	79	71	73	72	191,296	188,684
1/24/09	80	76	79	78	195,396	200,648
1/25/09	80	68	68	68	187,958	179,320
1/26/09	78	68	66	67	198,692	177,766
1/27/09	69	64	67	66	190,170	174,730
1/28/09	66	59	60	60	166,567	161,880
1/29/09	74	66	70	69	176,272	181,197
1/30/09	64	56	60	59	150,752	158,725
1/31/09	38	34	40	38	108,138	113,568
2/1/09	60	53	50	51	129,342	142,258
2/2/09	74	71	73	73	189,463	189,113
2/3/09	76	67	71	70	195,194	183,461
2/4/09	69	62	67	65	175,674	173,155
2/5/09	47	42	49	47	137,560	132,216
2/6/09	40	38	40	39	106,903	116,268
2/7/09	47	44	43	44	115,124	125,600
2/8/09	42	40	42	41	108,821	121,033
2/9/09	35	28	31	30	103,861	96,358
2/10/09	36	33	30	31	103,843	99,158
2/11/09	37	38	39	39	119,727	114,944
2/12/09	48	46	44	45	129,586	127,836
2/13/09	55	52	51	51	140,401	142,897
2/14/09	64	55	52	53	142,969	147,082
2/15/09	57	49	50	50	139,971	139,891
2/16/09	45	38	44	42	127,733	122,017
2/17/09	53	36	33	35	109,720	105,857
2/18/09	72	60	60	60	163,641	162,067
2/19/09	67	56	61	60	163,358	160,875
2/20/09	57	51	49	50	134,184	139,373
2/21/09	61	60	66	64	154,926	170,569
2/22/09	66	58	62	61	164,782	163,450
2/23/09	57	56	60	58	149,142	158,118
2/24/09	42	37	39	39	105,282	114,893
2/25/09	50	39	37	38	112,832	112,803
2/26/09	69	58	52	54	155,213	149,165
2/27/09	75	62	61	61	163,953	164,918
2/28/09	66	62	64	63	158,946	168,619
3/1/09	70	58	59	59	161,349	159,131
3/2/09	58	54	53	54	154,572	147,959
3/3/09	49	47	52	50	143,908	140,111
3/4/09	38	36	36	36	104,901	109,287
3/5/09	31	29	28	29	95,480	92,919

4/12/09	24	15	18	17	59,842	67,659
4/13/09	28	19	22	21	73,324	76,960
4/14/09	26	12	19	17	60,471	67,113
4/15/09	22	10	15	14	54,515	60,267
4/16/09	14	3	12	9	49,105	50,601
4/17/09	9	3	7	6	40,890	43,730
4/18/09	25	13	8	10	40,400	52,246
4/19/09	35	21	29	27	70,382	88,580
4/20/09	33	26	29	28	83,891	91,974
4/21/09	26	17	21	20	64,705	74,336
4/22/09	21	13	12	13	53,583	58,805
4/23/09	8	0	0	0	41,917	30,874
4/24/09	22	8	0	3	43,065	37,620
4/25/09	25	18	21	20	54,427	73,575
4/26/09	32	15	15	15	60,657	64,023
4/27/09	30	22	25	24	73,816	83,554
4/28/09	25	11	17	15	54,705	63,476
4/29/09	27	14	12	14	54,643	59,923
4/30/09	18	14	14	14	52,336	60,895
5/1/09	24	16	19	18	50,859	70,090
5/2/09	22	11	15	14	42,896	60,080
5/3/09	22	10	10	10	41,781	52,191
5/4/09	16	2	3	3	40,241	37,697
5/5/09	14	2	6	5	39,318	40,935
5/6/09	5	3	9	7	39,943	45,364
5/7/09	12	4	7	6	40,059	43,631
5/8/09	20	14	10	12	42,369	55,878
5/9/09	25	17	20	19	47,040	72,465
5/10/09	23	17	22	20	51,239	74,265
5/11/09	15	6	9	8	45,805	48,122
5/12/09	7	1	4	3	42,923	36,843
5/13/09	15	9	11	10	45,488	52,801
5/14/09	24	12	10	11	43,648	54,820
5/15/09	25	12	16	15	43,053	62,416
5/16/09	28	18	22	21	48,849	75,685
5/17/09	13	7	9	8	39,447	48,369
5/18/09	11	0	0	0	35,649	31,127
5/19/09	28	0	0	1	47,286	32,340
5/20/09	0	0	0	0	46,140	30,318
5/21/09	18	3	6	6	38,426	43,061
5/22/09	8	0	3	2	29,048	35,406
5/23/09	17	3	7	6	29,362	44,226
5/24/09	9	0	3	2	27,659	35,583
5/25/09	16	0	3	3	30,425	36,361
5/26/09	15	6	9	8	36,219	48,469
5/27/09	24	15	14	15	42,813	63,166
5/28/09	9	0	2	2	37,933	33,973
5/29/09	11	0	1	1	33,002	32,628
5/30/09	22	6	9	8	31,435	48,416
5/31/09	21	0	0	1	31,343	31,850
6/1/09	14	1	3	3	35,149	36,681
6/2/09	21	4	6	6	36,820	42,661
6/3/09	11	5	8	7	37,902	46,578
6/4/09	3	0	1	1	35,588	32,058
6/5/09	21	4	0	2	32,094	34,999
6/6/09	21	17	17	17	36,805	67,252
6/7/09	24	13	16	15	40,658	63,437
6/8/09	22	14	15	15	45,295	62,784
6/9/09	12	5	7	7	43,510	45,141
6/10/09	13	4	7	7	42,914	44,682
6/11/09	15	2	3	3	40,648	37,319
6/12/09	6	3	5	5	32,883	40,294

MINNESOTA ENERGY RESOURCES - PNG

Attachment 14

Customer Counts by PGAC Class - July 1, 2008 through June 30, 2009
NNG

Rate Class	Tariff Rate Designation	Jul-08 Average Customers	Aug-08 Average Customers	Sep-08 Average Customers	Oct-08 Average Customers	Nov-08 Average Customers	Dec-08 Average Customers	Jan-09 Average Customers	Feb-09 Average Customers	Mar-09 Average Customers	Apr-09 Average Customers	May-09 Average Customers	Jun-09 Average Customers
Residential w/ Heat	MN001/007/008	141,102	140,906	140,355	141,345	141,810	142,525	143,004	143,164	143,394	143,335	143,480	142,996
Residential w/o Heat	MN002/009010	969	771	949	958	958	979	975	972	965	988	998	958
Commercial-SV	MN050/053/054/070/076/078	5,977	5,993	6,340	5,995	5,974	6,065	6,100	6,121	6,110	6,103	6,071	6,008
Commercial-LV	MN056/060/063/064/065/071/077	7,752	7,705	7,684	7,715	7,772	7,836	7,872	7,894	7,860	7,874	7,938	7,816
SV-Joint	MN104	0	0	0	0	0	0	0	0	0	0	0	0
SV-Interruptible	MN125/128/135	357	354	351	350	358	353	361	353	353	473	351	345
LV-Interruptible	MN200/201/207	33	33	32	33	32	33	38	33	37	40	38	39
LV-Interruptible-ML	MN220/221	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN590	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN509/514/589	1	1	1	1	1	11	9	4	4	4	3	3
Transport	MN518	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN502/507/82L	0	0	0	0	0	0	0	1	1	0	0	0
Transport	MN500/574/81L	0	0	0	0	0	2	9	0	1	0	0	0
Transport	MN501/506/522/523/80L	15	15	15	15	16	30	15	15	15	15	49	14
Transport	MN/504/505/539	15	15	13	1	12	17	13	13	13	17	40	13
Transport	MN/512	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/515	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/517	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/519	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/535	0	0	0	0	0	0	0	0	0	0	0	0
Total		156,221	155,793	155,740	156,413	156,933	157,851	158,396	158,570	158,753	158,849	158,968	158,192

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Projected Fixed Cost - November 2009 through March 2010

[TRADE SECRET DATA BEGINS

Fixed Price WACOG

NNG-PNG
Fixed Price

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Projected Storage/Exchange Volumes Cost - November 2009 through March 2010

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Call/Put Options WACOG

[TRADE SECRET DATA BEGINS

Contract = 10,000

NNG

Call/Put Options

Nov-09														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost

Dec-09														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost

Jan-10														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost

Feb-10														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost

Mar-10														
Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost

Total														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost