DORSEY
DORSEY & WHITNEY LLP

MICHAEL J. AHERN
(612) 340-2881
FAX (612) 340-2643
ahern.michael@dorsey.com

November 2, 2009

VIA ELECTRONIC FILING

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

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

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–NMU for Approval of a Change in Demand Entitlement;
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 18 of the Petition and Attachments 5, 10, and 13 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 – NMU for Approval of a	)	Docket No. _______________
Change in Demand Entitlement	)	

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NMU (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC's NMU customers. 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-NMU Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-NMU 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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Betsy Wergin	Commissioner

In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – NMU for Approval of a	)	Docket No. _______________
Change in Demand Entitlement	)	

SUMMARY OF FILING

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

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

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 – NMU	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement	)	

PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

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

II. DISCUSSION

A. MERC's NMU Design Day Requirements

MERC's 2009-2010 NMU design day requirements increased 2,718 Mcf (or approximately 4.455 percent) from 61,008 Mcf to 63,726 Mcf.

Table 1: MERC's Proposed Reserve Margins
For the 2008-2009 Heating Season
NMU (NNG, GLGT, VGT & Centra)

	Reserve Margin 2009-2010 Heating Season	Reserve Margin 2008-2009 Heating Season	Change
NNG Zone E-F	4.70%	1.74%	2.96%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for NMU 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 Attachment 5 and Attachment 7 under the NNG-PNG 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-PNG Entitlement Allocation.

The difference between the total Design Day requirement and total Design Day capacity results in a 11.68% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day requirement for NMU-Centra 9,190 Mcf as calculated in the NMU Attachment 1, Page 2 of 3.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day capacity for NMU-Centra is 9,858 Mcf as calculated in NMU Attachment 4, Page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 7.27% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day requirement for NMU_GLGT is 14,848 Dth as calculated in the NMU Attachment 1, Page 2 of 3.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day capacity on is 16,446 Mcf as calculated in NMU Attachment 4, Page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 10.76% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day requirement for NMU_VGT is 12,882 Dth as calculated in the NMU Attachment 1, Page 2 of 3.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day capacity on is 13,868 Mcf as calculated in NMU Attachment 4, Page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 7.65% 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 **Regression Generation of Net Daily Metered Volumes** 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[1] .
    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).

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[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[2]. 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[3], calendar month, (service) area, city, location, zip code and

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

[3] 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. Maximum Daily Quantity (MDQ):

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 11, Pages 1 through 4. 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 any interstate pipeline(s). 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 8,120 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 8,120 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 12.

C. MERC's Specific NMU Proposed 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 NMU 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 Peoples' Attachment 3, MERC PNG_NNG proposes to decrease its approved total heating season entitlement by 1,052 Mcf/day (or approximately 1.62 percent). To obtain the proposed entitlement level, the Company proposes changes to its portfolio of capacity services identified below in Table 4.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)
NNG TF12B & TF12V	3,460 Mcf/Day
NNG TF5	(3,460) Mcf/Day
NNG TFX5	0 Mcf/Day
NNG LS Power	(52) Mcf/Day
NNG Subtotal	(52) Mcf/Day
GLGT FT0016	0 Mcf/Day
GLGT FT0155	0 Mcf/Day
GLGT FT8466	(1,000) Mcf/Day
VGT FA AF0012	0 Mcf/Day
VGT - Cap Release	0 Mcf/Day
VGT FT-A Backhaul	0 Mcf/Day
NNG Chisago TF12	1,398 Mcf/Day
NNG Chisago TF5	(1,526) Mcf/Day
NNG Chisago TFX 12	(235) Mcf/Day
NNG Chisago TFX 5	363 Mcf/Day
Centra TF	0 Mcf/Day
Nexen PSO	0 Mcf/Day
Total Overall Change	(1,052) Mcf/Day

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC_NMU proposes a decrease of Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability.

D. Financial Option Units and Premiums

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2009/2010 winter (November through March). Please see Attachment 5.

ii. Total premium cost to enter into the financial Call Options on behalf of MERC's firm customers amounted to $1,041,321 for the 2009/2010 winter. Please see Attachment 5.

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 5.

iv. Please see Attachment 5 for the various contract dates.

v. Please see Attachment 5 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 10, Pages 1 through 4.

E. Gas Supply.

The NMU 2009-2010 Winter Portfolio Plans - Minnesota Energy Resources Corporation for NNG, GLGT, VGT and Centra gas supply purchases for the Hedging Plans is in Attachment 10 pages 5 and 6. 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. Price Volatility

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 $5.25. Please see Attachment 15, page 1 of 3. MERC is projecting the storage WACOG on NNG to be approximately $3.57. 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 13, 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 13, 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 $5.38 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 purchased 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 7. 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 7, 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
121 Seventh Place East
St. Paul, MN 55101-5147

Robert S. Lee
Mackall Crounse & Moore PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402-2859

James D. Larson
Dahlen Berg & Co.
200 South Sixth Street
Suite 300
Minneapolis, MN 55402

Sharon Ferguson
MN Department of Commerce
85 Seventh Place East
Suite 500
St. Paul, MN 55101-2198

Michael Ahern
Dorsey & Whitney LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402-1498

Pam Marshall
Energy CENTS Coalition
823 East Seventh Street
St. Paul, MN 55106

Julia Anderson
Attorney General's Office
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Ann Seha
Dorsey & Whitney LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402-1498

Brian Meloy
Leonard, Street & Deinard
150 South Fifth Street
Suite 2300
Minneapolis, MN 55402

Ronald M. Giteck
Attorney General's Office-RUD
900 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101

Michael J. Bradley
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis, MN 55402-4129

Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street
Suite 350
Minneapolis, MN 55402-4629

Karen Finstad Hammel
Attorney General's Office
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Marie Doyle
CenterPoint Energy
800 LaSalle Avenue – Fl. 11
P.O. Box 59038
Minneapolis, MN 55459-0038

James R. Talcott
Northern Natural Gas Company
1111 South 103rd Street
Omaha, NE 68124

John Lindell
Attorney General's Office-RUD
900 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2130

Jack Kegel
MN Municipal Utilities Assn.
3025 Harbor Lane N.
Suite 400
Plymouth, MN 55447-5142

Greg Walters
Minnesota Energy Resources
3460 Technology Drive NW
Rochester, MN 55901

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2009

Design Day Requirement		60,918
Total Peak Day Entitlement		63,783
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 14)	46,401
Firm Annual Throughput - Minnesota		5,147,305
No. of Firm Customers		41,135
Department Load Factor Calculation		30.39%

MINNESOTA ENERGY RESOURCES - NMU

MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2009
HDD

Pipeline Group	2008/09 Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	% of total load	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	2008/09 Customer Growth	Total
NNG										
Peak	17,558	103	2,462	238		26,962	2,641	24,321	1.5%	24,680
Off Peak	17,558	55	2,462	238		15,545	880	14,665	1.5%	14,882
VGT										
VGT	5,719	109	3,306	81		12,181	4,427	7,754	1.5%	7,868
**VGT/GLGT	3,113	107	535	49	66.7%	5,818	(584)	6,402	1.5%	4,330
Peak	8,832		3,841	130				14,156		12,198
VGT	5,719	57	3,306	81		7,947	2,129	5,818	1.5%	5,904
VGT/GLGT	3,113	57	535	49	66.7%	3,349	(584)	3,933	1.5%	2,660
Off Peak	8,832		3,841	130				9,751		8,564
GLGT										
**VGT/GLGT	3,113	107	535	49	33.3%	5,818	(584)	6,402	1.5%	2,166
GLGT	8,104	106	634	133		14,644	2,146	12,497	1.5%	12,682
Peak	11,217		1,169	182				18,899		14,848
VGT/GLGT	3,113	57	535	49	33.3%	3,349	(584)	3,933	1.5%	1,331
GLGT	8,104	57	634	133		8,105	531	7,573	1.5%	7,685
Off Peak	11,217		1,169	182				11,506		9,016
Centra										
Peak	5,644	107	1,183	87		10,491	1,434	9,056	1.5%	9,190
Off Peak	5,644	57	1,183	87		6,141	415	5,726	1.5%	5,810
Total NMU										
Peak	40,138		8,120	589		70,096	10,064	60,030	1.5%	60,918
Off Peak	40,138		8,120	589		41,087	3,371	37,715	1.5%	38,272

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 Firm Joint volumes.
Footnote 3: Total equals Regression Total minus Regression Adjustment.

**Dual Supplied

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND PER CUSTOMER
NOVEMBER 1, 2009

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
09/10	41,135	60,918	1.48
08/09	39,112	63,726	1.63
07/08	38,258	61,008	1.59
06/07	38,483	61,060	1.59
05/06	38,208	62,107	1.63
04/05	39,816	60,703	1.52
03/04	37,076	62,194	1.68

MINNESOTA ENERGY RESOURCES - NMU

SUMMER/WINTER USAGE - Mcf
PROJECTED 12 MONTHS ENDING JUNE 2010

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	1,400,460	3,746,846	5,147,305
IS	272,164	562,076	834,240
IL	108,818	224,732	333,551
Total	1,781,442	4,533,654	6,315,096

MINNESOTA ENERGY RESOURCES - NMU

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2009

Type of Capacity or Entitlement		Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
NNG TF 12 Base & Variable		9,296	3,460	12,756
NNG TF 5		5,451	(3,460)	1,991
NNG TFX 5		6,139	0	6,139
LS Power		2,777	(52)	2,725
Peak Capacity		0	0	0
NNG Offpeak TFX*		0	0	0
NNG Subtotal		23,663	(52)	23,611
GLGT FT	FT0016	10,130	0	10,130
GLGT FT (12)	FT0155	1,178	0	1,178
GLGT FT (5)	FT0155	2,138	0	2,138
GLGT FT	FT8466	4,000	(1,000)	3,000
VGT FT-A	AF0012	7,966	0	7,966
VGT - Cap. Release	RF0361	0	0	0
VGT FT-A (4)	AF0160	5,902	0	5,902
NNG-TF12 Base	112495	926	442	1,368
NNG-TF12 Variable	112495	0	955	955
NNG-TF5 Chisago	112495	2,089	(1,526)	563
NNG-TFX 12 Chisago	112486	2,324	(235)	2,089
NNG-TFX 5 Chisago	112486	563	363	926
CENTRA FT-1		9,858	0	9,858
Nexen PSO		0	0	0
Total Entitlement		64,835	(1,052)	63,783
Forecasted Design Day-Adjusted		61,008	(90)	60,918
Capacity Surplus/Shortage		3,827	(962)	2,865
Reserve Margin		6.27%		4.70%

*Not included in total firm entitlement

MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2009

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:				**140**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-56.60%	24.34%	$0.8990
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0761	-5.77%	-5.99%	-1.55%	($0.0169)
Commodity Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9805	-33.40%	-40.04%	12.43%	$0.8821
Avg Annual Cost	$1,674.70	$1,397.07	$1,398.98	$992.01	$1,115.28	-33.40%	-40.04%	12.43%	$123.27
Effect of proposed commodity change on average annual bills:									$125.64
Effect of proposed demand change on average annual bills:									($2.36)
2) Large General Service: Avg. Annual Use:				**6,917**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-33.99%	24.34%	$0.8990
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0761	-5.77%	-2.16%	-1.55%	($0.0169)
Commodity Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	19.14%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9805	-33.40%	-20.17%	12.43%	$0.8821
Avg Annual Cost	$82,887.02	$69,146.07	$69,240.83	$49,098.36	$55,199.68	-33.40%	-20.17%	12.43%	$6,101.33
Effect of proposed commodity change on average annual bills:									$6,218.22
Effect of proposed demand change on average annual bills:									($116.89)
3) SV Interruptible Service: Avg. Annual Use:				**6,333**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-33.99%	24.34%	$0.8990
Commodity Margin	$1.0127	$0.8500	$1.0127	$1.0127	$1.0127	0.00%	19.14%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.8058	$7.5905	$4.7055	$5.6045	-41.26%	-28.20%	19.11%	$0.8990
Avg Annual Cost	$60,427.08	$49,434.76	$48,071.24	$29,800.31	$35,493.75	-41.26%	-28.20%	19.11%	$5,693.44
Effect of proposed commodity change on average annual bills:									$5,693.44
4) LV Interruptible Service: Avg. Annual Use:				**37,114**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-33.99%	24.34%	$0.8990
Commodity Margin	$0.3395	$0.2850	$0.3395	$0.3395	$0.3395	0.00%	19.12%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$7.2408	$6.9173	$4.0323	$4.9313	-44.39%	-31.90%	22.29%	$0.8990
Avg Annual Cost	$329,141.81	$268,738.09	$256,731.58	$149,656.48	$183,022.34	-44.39%	-31.90%	22.29%	$33,365.86
Effect of proposed commodity change on average annual bills:									$33,365.86

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

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MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2009

DEMAND

Contract Type / Northern Natural Gas (NNG)	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Rate ($/therm)
TF12-B (Max Rate)	Annual	7,513	12	$7.57760	$683,166.11	54,645,910	$0.01250
TF12-V (Max Rate)	Annual	5,243	12	$9.09260	$572,070.02	54,645,910	$0.01047
TF5 (Max Rate)	Winter	1,991	5	$15.15300	$150,848.12	54,645,910	$0.00276
TFX5 (Max Rate)	Winter	6,139	5	$15.15300	$465,121.34	54,645,910	$0.00851
SMS	Annual	2,103	12	$2.18000	$55,014.48	54,645,910	$0.00101
FDD - Reservation	Annual	6,833	12	$1.71400	$140,541.14	54,645,910	$0.00257
FDD - Storage Cycle	Annual	78,790	5	$0.35670	$140,521.97	54,645,910	$0.00257
FDD - Reservation	Annual	515	12	$3.31570	$20,491.03	54,645,910	$0.00037
FDD - Storage Cycle	Annual	5,933	5	$0.69010	$20,471.82	54,645,910	$0.00037
FDD - Reservation	Annual	482	12	$1.71400	$9,913.78	54,645,910	$0.00018
FDD - Storage Cycle	Annual	5,563	5	$0.35670	$9,921.61	54,645,910	$0.00018
LS Power	Winter	2,725	3	$4.34625	$35,530.59	54,645,910	$0.00065
Exchange	Annual	0	1	$2.00350	$0.00	54,645,910	$0.00000
NNG Demand					**$2,303,612**	54,645,910	**$0.04216**
Viking (VGT)							
FT	Annual	7,966	12	$3.46710	$331,427.02	54,645,910	$0.00606
FT	Winter	5,902	4	$3.76710	$88,933.70	54,645,910	$0.00163
TF-12 B	Summer	1,368	12	$7.57758	$124,431.88	54,645,910	$0.00228
TF-12 V	Summer	955	12	$9.09258	$104,231.65	54,645,910	$0.00191
TF-5	Winter	563	5	$15.15300	$42,672.32	54,645,910	$0.00078
TFX-12	Summer	2,089	12	$9.62883	$241,411.18	54,645,910	$0.00442
TFX-5	Winter	926	5	$15.15300	$70,141.03	54,645,910	$0.00128
VGT Demand					**$1,003,249**	54,645,910	**$0.01836**
Great Lakes (GLGT)							
FT	Annual	10,130	12	$3.45800	$420,354.48	54,645,910	$0.00769
FT	Annual	1,178	12	$3.45800	$48,882.29	54,645,910	$0.00089
FT	Winter	2,138	5	$3.45800	$36,966.02	54,645,910	$0.00068
T	Summer	0	7	$10.27800	$0.00	54,645,910	$0.00000
FT	Annual	3,000	12	$3.45800	$124,488.00	54,645,910	$0.00228
GLGT Demand					**$630,691**	54,645,910	**$0.01154**
Centra							
FT	Annual	9,858	12	$1.23110	$145,634.21	54,645,910	$0.00267
FT	Annual	9,858	12	$4.49324	$531,532.19	54,645,910	$0.00973
Balancing	Annual	9,858	12	$0.4565	$54,000.00	54,645,910	$0.00099
Centra Demand					**$731,166**	54,645,910	**$0.01338**
Nexen	Annual	684,604	1	$1.77	$1,211,749.08	54,645,910	$0.02217
Nexen Demand					**$1,211,749**	0	**$0.02217**
NMU DEMAND - $/Ccf					**$5,880,467**		**$0.10761**

For Joint Rate Demand				**54,645,910**	**Annual Firm Sales in therms**
Northern Natural Gas (NNG)					
TF12-B (Max Rate)	Annual	7,513	12		
TF12-V (Max Rate)	Annual	5,243	12		
TF5 (Max Rate)	Winter	1,991	5		
TFX5 (Max Rate)	Winter	6,139	5		
			193,722		
Viking (VGT)					
FT	Annual	7,966	12		
TF-12 B	Summer	1,368	12		
TF-12 V	Summer	955	12		
TF-5	Winter	563	5		
TFX-12	Summer	2,089	12		
TFX-5	Winter	926	5		
			151,364		
Great Lakes (GLGT)					
FT	Annual	10,130	12		
FT	Annual	1,178	12		
FT	Winter	2,138	5		
			146,386		
Centra					
FT	Annual	9,858	12		
			118,296		
Total Demand Cost			**$5,880,467**		
Total Demand Weighted Vol in therms			**6,097,682**		
Total Joint Demand Rate $/therm				**$0.96438**	**/therm**

MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2009

PRESENT AVERAGE COST OF GAS **EFFECTIVE:** **01-Nov-09**

COMMODITY

WACOG		Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm	REFERENCE	Effective
NNG								
GAS COST		$4.92570						
FUEL	0.60%	$0.02973					Sub 21 Revised Sheet	Apr 1, 2006
COMMODITY TRANSPORTATION		$0.03620					3 Rev 72 Revised Shee	Oct 1, 2006
ACA		$0.00190					4 Rev 72 Revised Shee	Oct 1, 2007
GRI FEE		$0.00000					3 Rev 72 Revised Shee	Oct 1, 2006
NNG Commodity		$4.99353	2,503,071	$60,591	$12,559,752	$0.18810	**NNG Commodity**	
VGT								
GAS COST		$4.29970						
FUEL	0.64%	$0.02770					Sub 16th Revised Shee	Apr. 1, 2006
COMMODITY TRANSPORTATION		$0.01300					Sub 16th Revised Shee	Apr. 1, 2006
GRI		$0.00000					Sub 16th Revised Shee	Apr. 1, 2006
ACA		$0.00190					Sub 16th Revised Shee	Apr. 1, 2006
VGT Commodity		$4.34230	1,820,220	$20,197	$7,924,140	$0.11867	**VGT Commodity**	
GLGT								
GAS COST		$4.26740						
FUEL	0.829%	$0.03569						
COMMODITY TRANSPORTATION		$0.00326					5 Revised Sheet 4	Jun 1, 1997
GRI		$0.00000					Contract	Jun. 1, 2004
ACA		$0.00190					18th Revised Sheet No	Oct. 1, 2005
GLGT Commodity		$4.30825	962,512	$20,197	$4,166,937	$0.06240	**GLGT Commodity**	
CENTRA								
CENTRA TRANSMISSION	($Cdn/103M3)	1.062					Sheet 1 (N.E.B.)	
Conversion x0.9306		$0.02801						
GAS COSTS		$4.27610						
CUSTOMS FEE		$0.00029						
CENTRA Commodity		$4.30440	1,391,502	$20,197	$6,009,772	$0.09000	**Centra Commodity**	
NMU Weighted Average gas cost - $/Dth			**6,677,305**	**$121,182**	**$30,660,601**	**$0.45918**	**NMU WACOG-$/therm**	
		Total Annual Sales in therms	**66,773,050**					

MINNESOTA ENERGY RESOURCES - NMU

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

NOVEMBER 1, 2009

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:				**140**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-55.86%	25.73%	$0.9502
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0135	-11.25%	-11.68%	-7.27%	($0.0795)
Commodity Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9691	-33.50%	-40.16%	12.27%	$0.8707
Avg Annual Cost	$1,674.70	$1,397.07	$1,398.98	$992.01	$1,113.69	-33.50%	-40.16%	12.27%	$121.68
Effect of proposed commodity change on average annual bills:									$132.79
Effect of proposed demand change on average annual bills:									($11.11)
2) Large General Service: Avg. Annual Use:				**6,917**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-33.25%	25.73%	$0.9502
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0135	-11.25%	-7.86%	-7.27%	($0.0795)
Commodity Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	19.14%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9691	-33.50%	-20.28%	12.27%	$0.8707
Avg Annual Cost	$82,887.02	$69,146.07	$69,240.83	$49,098.36	$55,120.83	-33.50%	-20.28%	12.27%	$6,022.48
Effect of proposed commodity change on average annual bills:									$6,572.36
Effect of proposed demand change on average annual bills:									($549.89)
3) SV Interruptible Service: Avg. Annual Use:				**6,333**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-33.25%	25.73%	$0.9502
Commodity Margin	$1.0127	$0.8500	$1.0127	$1.0127	$1.0127	0.00%	19.14%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.8058	$7.5905	$4.7055	$5.6557	-40.73%	-27.54%	20.19%	$0.9502
Avg Annual Cost	$60,427.08	$49,434.76	$48,071.24	$29,800.31	$35,818.00	-40.73%	-27.54%	20.19%	$6,017.69
Effect of proposed commodity change on average annual bills:									$6,017.69
4) LV Interruptible Service: Avg. Annual Use:				**37,114**	**Mcf**				
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-33.25%	25.73%	$0.9502
Commodity Margin	$0.3395	$0.2850	$0.3395	$0.3395	$0.3395	0.00%	19.12%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$7.2408	$6.9173	$4.0323	$4.9825	-43.82%	-31.19%	23.56%	$0.9502
Avg Annual Cost	$329,141.81	$268,738.09	$256,731.58	$149,656.48	$184,922.60	-43.82%	-31.19%	23.56%	$35,266.12
Effect of proposed commodity change on average annual bills:									$35,266.12

Note: Average Annual Average based on NMU 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 - NMU

(Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)
NOVEMBER 1, 2009

DEMAND

Contract Type / Northern Natural Gas (NNG)	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Rate ($/therm)
TF12-B (Max Rate)	Annual	7,513	12	$7.57760	$683,166.11	54,645,910	$0.01250
TF12-V (Max Rate)	Annual	5,243	12	$9.09260	$572,070.02	54,645,910	$0.01047
TF5 (Max Rate)	Winter	1,991	5	$15.15300	$150,848.12	54,645,910	$0.00276
TFX5 (Max Rate)	Winter	6,139	5	$15.15300	$465,121.34	54,645,910	$0.00851
SMS	Annual	2,103	12	$2.18000	$55,014.48	54,645,910	$0.00101
LS Power	Winter	2,725	3	$4.34625	$35,530.59	54,645,910	$0.00065
Exchange	Annual	0	1	$2.00350	$0.00	54,645,910	$0.00000
NNG Demand					**$1,961,751**	54,645,910	**$0.03590**
Viking (VGT)							
FT	Annual	7,966	12	$3.46710	$331,427.02	54,645,910	$0.00606
FT	Winter	5,902	4	$3.76710	$88,933.70	54,645,910	$0.00163
TF-12 B	Summer	1,368	12	$7.57758	$124,431.88	54,645,910	$0.00228
TF-12 V	Summer	955	12	$9.09258	$104,231.65	54,645,910	$0.00191
TF-5	Winter	563	5	$15.15300	$42,672.32	54,645,910	$0.00078
TFX-12	Summer	2,089	12	$9.62883	$241,411.18	54,645,910	$0.00442
TFX-5	Winter	926	5	$15.15300	$70,141.03	54,645,910	$0.00128
VGT Demand					**$1,003,249**	54,645,910	**$0.01836**
Great Lakes (GLGT)							
FT	Annual	10,130	12	$3.45800	$420,354.48	54,645,910	$0.00769
FT	Annual	1,178	12	$3.45800	$48,882.29	54,645,910	$0.00089
FT	Winter	2,138	5	$3.45800	$36,966.02	54,645,910	$0.00068
IT	Summer	0	7	$10.27800	$0.00	54,645,910	$0.00000
FT	Annual	3,000	12	$3.45800	$124,488.00	54,645,910	$0.00228
GLGT Demand					**$630,691**	54,645,910	**$0.01154**
Centra							
FT	Annual	9,858	12	$1.23110	$145,634.21	54,645,910	$0.00267
FT	Annual	9,858	12	$4.49324	$531,532.19	54,645,910	$0.00973
Balancing	Annual	9,858	12	$4,500.00	$54,000.00	54,645,910	$0.00099
Centra Demand					**$731,166**	54,645,910	**$0.01338**
Nexen	Annual	684,604	1	$1.77	$1,211,749.08	54,645,910	$0.02217
Nexen Demand					**$1,211,749**	0	**$0.02217**
NMU DEMAND - $/Ccf					**$5,538,606**		**$0.10135**

For Joint Rate Demand				**54,645,910**	**Annual Firm Sales in therms**
Northern Natural Gas (NNG)					
TF12-B (Max Rate)	Annual	7,513	12		
TF12-V (Max Rate)	Annual	5,243	12		
TF5 (Max Rate)	Winter	1,991	5		
TFX5 (Max Rate)	Winter	6,139	5		
			193,722		
Viking (VGT)					
FT	Annual	7,966	12		
TF-12 B	Summer	1,368	12		
TF-12 V	Summer	955	12		
TF-5	Winter	563	5		
TFX-12	Summer	2,089	12		
TFX-5	Winter	926	5		
			151,364		
Great Lakes (GLGT)					
FT	Annual	10,130	12		
FT	Annual	1,178	12		
FT	Winter	2,138	5		
			146,386		
Centra					
FT	Annual	9,858	12		
			118,296		
Total Demand Cost			**$5,538,606**		
Total Demand Weighted Vol in therms			**6,097,682**		
Total Joint Demand Rate $/therm				**$0.90831**	**/therm**

MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2009

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

PRESENT AVERAGE COST OF GAS **EFFECTIVE: 01-Nov-09**

COMMODITY

NNG	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate ($/therm)
FDD - Reservation	Annual	6,833	12	$1.71400	#########	2,503,071	$0.05615
FDD - Storage Cycle	Annual	78,790	5	$0.35670	#########	2,503,071	$0.05614
FDD - Reservation	Annual	515	12	$3.31570	$20,491.03	2,503,071	$0.00819
FDD - Storage Cycle	Annual	5,933	5	$0.69010	$20,471.82	2,503,071	$0.00818
FDD - Reservation	Annual	482	12	$1.71400	$9,913.78	2,503,071	$0.00396
FDD - Storage Cycle	Annual	5,563	5	$0.35670	$9,921.61	2,503,071	$0.00396
					$341,861.34	2,503,071	$0.13658

		WACOG Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm	REFERENCE	Effective
GAS COST		$4.92570						
FUEL	0.60%	$0.02973					Sub 21 Revised Sheet N	Apr 1, 2006
COMMODITY TRANSPORTATION		$0.03620					3 Rev 72 Revised Sheet	Oct 1, 2006
ACA		$0.00190					4 Rev 72 Revised Sheet	Oct 1, 2007
GRI FEE		$0.00000					3 Rev 72 Revised Sheet	Oct 1, 2006
NNG Commodity		$4.99353	2,503,071	$60,591	$12,901,613	$0.19322	**NNG Commodity**	
VGT								
GAS COST		$4.29970						
FUEL	0.64%	$0.02770					Sub 16th Revised Sheet	Apr. 1, 2006
COMMODITY TRANSPORTATION		$0.01300					Sub 16th Revised Sheet	Apr. 1, 2006
GRI		$0.00000					Sub 16th Revised Sheet	Apr. 1, 2006
ACA		$0.00190					Sub 16th Revised Sheet	Apr. 1, 2006
VGT Commodity		$4.34230	1,820,220	$20,197	$7,924,140	$0.11867	**VGT Commodity**	
GLGT								
GAS COST		$4.26740						
FUEL	0.829%	$0.03569						
COMMODITY TRANSPORTATION		$0.00326					5 Revised Sheet 4	Jun 1, 1997
GRI		$0.00000					Contract	Jun. 1, 2004
ACA		$0.00190					18th Revised Sheet No.	Oct. 1, 2005
GLGT Commodity		$4.30825	962,512	$20,197	$4,166,937	$0.06240	**GLGT Commodity**	
CENTRA								
CENTRA TRANSMISSION	($Cdn/103M3)	1.062					Sheet 1 (N.E.B.)	
Conversion x0.9306		$0.02801						
GAS COSTS		$4.27610						
CUSTOMS FEE		$0.00029						
CENTRA Commodity		$4.30440	1,391,502	$20,197	$6,009,772	$0.09000	**Centra Commodity**	
NMU Weighted Average gas cost - $/Dth			6,677,305	$121,182	$31,002,462	$0.46430	**NMU WACOG-$/therm**	
	Total Annual Sales in therms		66,773,050					

*****PUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA*****

MINNESOTA ENERGY RESOURCES - NMU

Attachment 5

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		10,000		12,581		13,871		12,857		10,323	59,631	1,800,000

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	**121,172**	0.5838	**227,685**	0.5671	**243,852**	0.6151	**221,426**	0.71	**227,186**	0.5785	**$ 1,041,321**

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

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

MINNESOTA ENERGY RESOURCES - NMU

Attachment 6
NMU

	M-05-1727 NMU GS	M-06- NMU GS	G007/ M-07-1402 NMU GS	**M-08-1329 NMU GS**	**M-09- NMU GS**	Proposed Change
NNG Design Day	23,197	21,635	21,491	**21,791**	**24,680**	2,889
Customer Requirements moving to Transportation	125					
Adjusted Design Day	23,072					
Adjusted Design Day Percentages	3.89%	100.00%	100.00%	**100.00%**	**100.00%**	0.00%
Factors for All Winter Capacity	5.67%	100.00%	100.00%	**100.00%**	**100.00%**	0.00%
NNG Allocated Entitlements in PGA						
TF12B	8,613	7,340	2,954	**2,653**	**7,513**	4,860
TF12V	0	5,930	9,802	**6,643**	**5,243**	-1,400
TF(5)	10,611	2,102	1,991	**5,451**	**1,991**	-3,460
TFX(5)	2,831	5,514	6,139	**6,139**	**6,139**	0
LS Power		0	2,725	**2,777**	**2,725**	-52
TFX(5)	766	0	0	**0**	**0**	0
Peak Capacity 3 mo.	1,418	0	0	**0**	**0**	0
Total NNG Allocated Entitlements in PGA	24,238	20,886	23,611	**23,663**	**23,611**	-52
Other Pipelines Entitlements in PGA						
Viking FT-A	8,366	7,966	7,966	**7,966**	**7,966**	0
Viking FT-A Backhaul	1,900	4,625	5,902	**5,902**	**5,902**	0
Viking/NNG Chisago TF12 Base	1,303	1,821	782	**926**	**1,368**	442
Viking/NNG Chisago TF12 Variable	0	0	0	**0**	**955**	955
Viking/NNG Chisago TF5	2,839	441	1,765	**2,089**	**563**	-1,526
Viking/NNG Chisago TFX 12	0	725	1,963	**2,324**	**2,089**	-235
Viking/NNG Chisago TFX 5	0	1,637	476	**563**	**926**	363
Great Lakes FT-A (12)	13,130	11,308	14,308	**15,308**	**14,308**	-1,000
Great Lakes FT-A (5)	0	2,138	2,138	**2,138**	**2,138**	0
Centra FT-1	8,358	9,858	9,858	**9,858**	**9,858**	0
Centra -Boise	1,500	0	0	**0**	**0**	0
Nexen Exchange	4,600	6,000	0	**0**	**0**	0
Tenaska PSO GL	86,549	0	0	**0**	**0**	0
Tenaska PSO Centra	62,000	0	0	**0**	**0**	0
ANR Storage	0	0	0	**0**	**0**	0
Total Capacity	212,883	62,780	62,867	**64,835**	**63,783**	-1,052
Total NNG Transportation	24,238	20,886	23,611	**23,663**	**23,611**	-52
Total Transportation	59,734	56,780	62,867	**64,835**	**63,783**	-1,052
Total Seasonal Transportation	15,625	7,616	10,855	**14,367**	**10,855**	-3,512
Percent Seasonal on NNG	64.5%	36.5%	46.0%	**60.7%**	**46.0%**	-14.7%
Other Entitlements not included in Peak Day Deliverability						
TFX Offpeak Old (Apr/Oct) one mo.	3,694	0	0	**0**	**0**	0
TFX (Apr/Oct) one mo.	2,108	0	0	**0**	**0**	0
TFX Apr.-Oct. 7 mos.	329	0	0	**0**	**0**	0
TFX May-Sept 5 mos.	568	0	0	**0**	**0**	0
FDD Storage reservation per mo.	5,402	6,343	7,619	**7,980**	**7,830**	-150
FDD Storage capacity per mo.	311,440	365,682	428,702	**460,070**	**451,428**	-8,642
ANR Capacity per mo.	0	0	0	**0**	**0**	0
Nexen PSO	9,916	600,000	684,604	**684,604**	**684,604**	0
Tenaska PSO	19,443	15,807	17,763	**0**	**0**	0
NGPL per mo.	138,365	0	0	**0**	**0**	0
SMS per mo.	2,100	1,907	2,172	**2,143**	**2,103**	-40
SBA	0	0	0	**0**	**0**	0
Upstream Demand per mo.	32	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - NMU

Attachment 7
Rate Impacts
NMU

General Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-30.19%	24.34%	$0.8990
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0761	-5.77%	-3.93%	-1.55%	($0.0169)
Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9805	-33.40%	-20.28%	12.43%	$0.8821
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas*	$1,674.70	$1,397.07	$1,398.98	$992.01	$1,115.28	-33.40%	-20.28%	12.43%	$123.27

Large General Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-30.19%	24.34%	$0.8990
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0761	-5.77%	-3.93%	-1.55%	($0.0169)
Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9805	-33.40%	-20.28%	12.43%	$0.8821
Average Annual Use	6,917	6,917	6,917	6,917	6,917				
Average Annual Cost of Gas*	$82,887.02	$69,146.07	$69,240.83	$49,098.36	$55,199.68	-33.40%	-20.28%	12.43%	$6,101.33

SV Interruptible Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-30.19%	24.34%	$0.8990
Commodity Margin	$1.0127	$0.8500	$1.0127	$1.0127	$1.0127	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.8058	$7.5905	$4.7055	$5.6045	-41.26%	-26.16%	19.11%	$0.8990
Average Annual Use	6,333	6,333	6,333	6,333	6,333				
Average Annual Cost of Gas*	$60,427.08	$49,434.76	$48,071.24	$29,800.31	$35,493.75	-41.26%	-26.16%	19.11%	$5,693.44

LV Interruptible Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.5918	-46.16%	-30.19%	24.34%	$0.8990
Commodity Margin	$0.3395	$0.2850	$0.3395	$0.3395	$0.3395	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$7.2408	$6.9173	$4.0323	$4.9313	-44.39%	-28.71%	22.29%	$0.8990
Average Annual Use	37,114	37,114	37,114	37,114	37,114				
Average Annual Cost of Gas*	$329,141.81	$268,738.09	$256,731.58	$149,656.48	$183,022.34	-44.39%	-28.71%	22.29%	$33,365.86

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.8990	89.90%	($0.0155)	($0.0169)	-1.55%	$0.8821	12.43%	$123.27
Large General Service	$0.8990	89.90%	($0.0155)	($0.0169)	-1.55%	$0.8821	12.43%	$6,101.33
SV Interruptible Service	$0.8990	$0.8990	$0.0000	$0.0000	0.00%	$0.8990	19.11%	$5,693.44
LV Interruptible Service	$0.8990	$0.8990	$0.0000	$0.0000	0.00%	$0.8990	22.29%	$33,365.86

***** Average Annual Bill amount does not include customer charges.
****** Commodity includes Upstream costs.
^ Implemented with Interim rates
^^ Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

Attachment 7

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

NMU

General Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-29.41%	25.73%	$0.9502
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0135	-11.25%	-9.52%	-7.27%	($0.0795)
Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9691	-33.50%	-20.39%	12.27%	$0.8707
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas*	$1,674.70	$1,397.07	$1,398.98	$992.01	$1,113.69	-33.50%	-20.39%	12.27%	$121.68

Large General Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-29.41%	25.73%	$0.9502
Demand Cost	$1.1420	$1.0999	$1.1201	$1.0930	$1.0135	-11.25%	-9.52%	-7.27%	($0.0795)
Margin	$2.3126	$1.9411	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$9.9968	$10.0105	$7.0984	$7.9691	-33.50%	-20.39%	12.27%	$0.8707
Average Annual Use	6,917	6,917	6,917	6,917	6,917				
Average Annual Cost of Gas*	$82,887.02	$69,146.07	$69,240.83	$49,098.36	$55,120.83	-33.50%	-20.39%	12.27%	$6,022.48

SV Interruptible Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-29.41%	25.73%	$0.9502
Commodity Margin	$1.0127	$0.8500	$1.0127	$1.0127	$1.0127	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.8058	$7.5905	$4.7055	$5.6557	-40.73%	-25.49%	20.19%	$0.9502
Average Annual Use	6,333	6,333	6,333	6,333	6,333				
Average Annual Cost of Gas*	$60,427.08	$49,434.76	$48,071.24	$29,800.31	$35,818.00	-40.73%	-25.49%	20.19%	$6,017.69

LV Interruptible Service	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	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.9558	$6.5778	$3.6928	$4.6430	-45.56%	-29.41%	25.73%	$0.9502
Commodity Margin	$0.3395	$0.2850	$0.3395	$0.3395	$0.3395	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$7.2408	$6.9173	$4.0323	$4.9825	-43.82%	-27.97%	23.56%	$0.9502
Average Annual Use	37,114	37,114	37,114	37,114	37,114				
Average Annual Cost of Gas*	$329,141.81	$268,738.09	$256,731.58	$149,656.48	$184,922.60	-43.82%	-27.97%	23.56%	$35,266.12

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.9502	95.02%	($0.0727)	($0.0795)	-7.27%	$0.8707	12.27%	$121.68
Large General Service	$0.9502	95.02%	($0.0727)	($0.0795)	-7.27%	$0.8707	12.27%	$6,022.48
SV Interruptible Service	$0.9502	$0.9502	$0.0000	$0.0000	0.00%	$0.9502	20.19%	$6,017.69
LV Interruptible Service	$0.9502	$0.9502	$0.0000	$0.0000	0.00%	$0.9502	23.56%	$35,266.12

***** Average Annual Bill amount does not include customer charges.
****** Commodity includes Upstream costs.
^ Implemented with Interim rates
^^ Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

Attachment 8
Change in Costs due to November 1, 2009 Change in Entitlement Levels and Related Demand Costs
NMU

	Oct. 2009 Entitlements	Nov. 2009 Entitlements	Entitlement Change	Oct. 2009 Rate	Months	Oct. 2009 Total Annual Cost	Nov. 2009 Total Annual Cost	Total Annual Cost Change
NNG Pipeline								
TF 12 B (Max Rate)	2,653	7,513	4,860	$ 7.5776	12	$241,240	$683,166	$441,926
TF 12 V (Max Rate)	6,643	5,243	-1,400	$ 9.0926	12	$724,824	$572,070	-$152,754
TF 5 (Max Rate)	5,451	1,991	-3,460	$15.1530	5	$412,995	$150,848	-$262,147
TFX 5 (Max Rate)	6,139	6,139	0	$15.1530	5	$465,121	$465,121	$0
LS Power	2,777	2,725	-52	$ 4.3463	3	$36,209	$35,531	-$678
NNG 3-Party demand								
Producer Demand	$0	$0	$0			$0	$0	$0
Call Options Premium	$2,024,198	#REF!	#REF!			$2,024,198	#REF!	#REF!
Upstream Demand Costs								
SMS	2,143	2,103	-40	$ 2.1800	12	$56,061	$55,014	-$1,046
FDD Storage Reservation Charge	7,455	7,315	-140	$ 1.7140	12	$153,334	$150,455	-$2,880
FDD Storage Cycle Volume	85,967	84,353	-1,614	$ 0.3567	5	$153,322	$150,444	-$2,879
FDD Storage Reservation Charge	524	515	-9	$ 3.3157	12	$20,849	$20,491	-$358
FDD Storage Cycle Volume	6,047	5,933	-114	$ 0.6901	5	$20,865	$20,472	-$393
Tenaska Storage	17,763	0	-17,763	$ 2.0035	1	$35,588	$0	-$35,588
Viking Pipeline								
FTA (AF0012)	7,966	7,966	0	$ 3.4671	12	$331,427	$331,427	$0
FT-A Zone 1-1 Backhaul	5,902	5,902	0	$ 3.7671	4	$88,934	$88,934	$0
NNG TF12 Chisago (112495) - Base	926	1,368	442	$ 7.5776	12	$84,202	$124,432	$40,230
NNG TFX12 Chisago (112486)	2,324	2,089	-235	$ 9.6288	12	$268,529	$241,411	-$27,118
NNG TF12 Chisago (112495) - Variable	0	955	955	$ 9.0926	12	$0	$104,232	$104,232
NNG TF5 Chisago (112495)	2,089	563	-1,526	$15.1530	5	$158,273	$42,672	-$115,601
NNG TF5 Chisago (112486)	563	926	363	$15.1530	5	$42,656	$70,141	$27,485
GLGTPipeline								
FT-0016	10,130	10,130	0	$ 3.4580	12	$420,354	$420,354	$0
FT-0155-12	1,178	1,178	0	$ 3.4580	12	$48,882	$48,882	$0
FT-0155-5	2,138	2,138	0	$ 3.4580	5	$36,966	$36,966	$0
FT-8466	4,000	3,000	-1,000	$ 3.4580	12	$165,984	$124,488	-$41,496
CENTRA Pipeline								
CENTRA Transmission ($cdn/103M3)				166.3160				
Centra Transmission	9,858	9,858	0	$ 4.4932	12	$531,532	$531,532	$0
Union Balancing	9,858	9,858	0	$ 0.4565	12	$54,000	$54,000	$0
Centra MN Pipelines	9,858	9,858	0	$ 1.2311	12	$145,634	$145,634	$0
NEXEN STORAGE								
Storage charge	684,604	684,604	0	$ 1.7700	1	$1,211,749	$1,211,749	$0
TOTAL DEMAND						$7,933,730	#REF!	#REF!
NMU's DE Attachment 4 page 2							$5,880,467	
							#REF!	

MINNESOTA ENERGY RESOURCES - NMU

Attachment 9

	1/20 Design Day HDD	NNG-NMU Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	103	2,462	238	1.50%	24,321	24,680
Off Peak	55	2,462	238	1.50%	14,665	14,882

	1/20 Design Day HDD	GLGT-NMU Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	106	812	149	1.50%	14,631	14,848
Off Peak	57	812	149	1.50%	9,751	9,016

	1/20 Design Day HDD	VGT-NMU Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	109	3,663	114	1.50%	12,022	12,198
Off Peak	57	3,663	114	1.50%	7,573	8,564

	1/20 Design Day HDD	Centra-NMU Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	107	1,183	87	1.50%	9,056	9,192
Off Peak	57	1,183	87	1.50%	5,726	5,812

	1/20 Design Day HDD	Total-NMU Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	0	8,120	588	1.50%	60,030	60,930
Off Peak	0	8,120	588	1.50%	37,715	38,281

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

[TRADE SECRET DATA BEGINS

Total													2,954,493	**100.00%**

TRADE SECRET DATA ENDS]

09/10 Winter Portfolio Plan - MERC GLGT-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

Total													980,827	**100.00%**

TRADE SECRET DATA ENDS]

09/10 Winter Portfolio Plan - MERC VGT-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

Total													993,103	**100.00%**

TRADE SECRET DATA ENDS]

09/10 Winter Portfolio Plan - MERC Centra-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

Total													859,587	**100.00%**

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (NMU)

NOVEMBER, 2008 THROUGH MARCH, 2009

[TRADE SECRET DATA BEGINS

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Daily Volumes Nov	Dec	Jan	Feb	Mar	Monthly Total
Total Actual Fixed/Option Physical					**5,001**	**4,839**	**5,484**	**4,645**	**5,485**	**770,144**

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Total Actual Seasonal Index				**5,000**	**6,452**	**6,774**	**6,429**	**5,161**	**900,023**

GAS DAILY PACKAGES

NO Gas Daily Peakers

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 119884 Volume Injected	Total Volume Injected
Total	**403,482**	**27,813**	**431,294**

[TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

MINNESOTA ENERGY RESOURCES

GLGT/VGT/Centra WINTER PLAN (NMU)

NOVEMBER, 2009 THROUGH MARCH, 2010

[TRADE SECRET DATA BEGINS

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total

PHYSICAL FIXED PRICE HEDGES		Trigger	Trigger		Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total
	Total Actual Fixed/Option Physical				-	-	-	-	-	-

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	Total Actual Seasonal Index			-	-	-	-	-	-

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	Total Actual Seasonal Index			-	-	-	-	-	-

GAS DAILY PACKAGES

NO Gas Daily Peakers

TRADE DATA SECRET ENDS]

STORAGE

No Storage

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

MINNESOTA ENERGY RESOURCES - NMU

Attachment 11

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

Base	7,102
Variable	734

Date	100.00% Cloquet Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/08	0	0	16,064	7,102
7/2/08	1	1	13,979	7,924
7/3/08	8	8	8,813	13,209
7/4/08	7	7	7,695	12,446
7/5/08	0	0	7,830	7,102
7/6/08	0	0	8,754	7,102
7/7/08	8	8	15,241	12,651
7/8/08	7	7	21,238	11,946
7/9/08	2	2	18,660	8,687
7/10/08	5	5	18,133	10,919
7/11/08	11	11	17,836	15,176
7/12/08	2	2	17,440	8,790
7/13/08	2	2	17,400	8,805
7/14/08	2	2	16,711	8,643
7/15/08	0	0	16,748	7,102
7/16/08	1	1	18,581	7,865
7/17/08	6	6	19,114	11,638
7/18/08	0	0	17,010	7,102
7/19/08	9	9	14,585	13,385
7/20/08	2	2	11,568	8,599
7/21/08	4	4	15,923	10,185
7/22/08	3	3	15,677	9,436
7/23/08	7	7	15,064	12,446
7/24/08	0	0	15,760	7,102
7/25/08	0	0	13,923	7,102
7/26/08	0	0	12,239	7,102
7/27/08	0	0	9,312	7,102
7/28/08	0	0	11,236	7,102
7/29/08	0	0	17,273	7,102
7/30/08	0	0	18,082	7,102
7/31/08	1	1	17,724	7,851
8/1/08	0	0	17,736	7,102
8/2/08	2	2	17,276	8,629
8/3/08	2	2	17,649	8,629
8/4/08	0	0	16,126	7,102
8/5/08	0	0	15,117	7,102
8/6/08	1	1	17,089	7,887
8/7/08	2	2	17,563	8,658
8/8/08	3	3	16,208	9,392
8/9/08	4	4	14,983	10,273
8/10/08	10	10	14,768	14,662
8/11/08	3	3	15,074	9,392
8/12/08	4	4	17,445	10,155
8/13/08	0	0	18,662	7,102
8/14/08	1	1	14,554	7,902
8/15/08	6	6	14,134	11,594
8/16/08	0	0	14,214	7,102
8/17/08	0	0	15,363	7,102
8/18/08	0	0	15,411	7,102

9/26/08	0	0	17,040	7,102
9/27/08	13	13	18,925	16,350
9/28/08	17	17	21,602	19,433
9/29/08	16	16	24,995	18,883
9/30/08	21	21	22,870	22,164
10/1/08	19	19	23,256	21,239
10/2/08	17	17	23,426	19,668
10/3/08	25	25	31,210	25,246
10/4/08	23	23	31,517	24,322
10/5/08	21	21	34,095	22,164
10/6/08	16	16	34,479	19,103
10/7/08	16	16	32,301	18,773
10/8/08	15	15	30,895	18,097
10/9/08	19	19	31,203	21,077
10/10/08	24	24	32,212	24,828
10/11/08	15	15	21,354	18,303
10/12/08	13	13	15,556	16,350
10/13/08	14	14	24,846	17,407
10/14/08	22	22	28,695	23,595
10/15/08	24	24	26,500	24,865
10/16/08	26	26	23,738	26,186
10/17/08	25	25	24,331	25,636
10/18/08	25	25	20,188	25,335
10/19/08	17	17	21,561	19,668
10/20/08	31	31	27,367	30,091
10/21/08	29	29	26,783	28,682
10/22/08	29	29	30,662	28,109
10/23/08	24	24	26,019	24,380
10/24/08	24	24	25,148	24,894
10/25/08	21	21	21,249	22,303
10/26/08	28	28	27,756	27,537
10/27/08	37	37	38,234	34,231
10/28/08	32	32	36,505	30,443
10/29/08	29	29	32,761	28,476
10/30/08	14	14	26,464	17,503
10/31/08	25	25	28,761	25,166
11/1/08	25	25	22,155	25,599
11/2/08	20	20	19,868	21,745
11/3/08	16	16	21,228	18,883
11/4/08	7	7	20,557	12,548
11/5/08	12	12	24,862	15,660
11/6/08	20	20	24,934	21,885
11/7/08	32	32	25,280	30,304
11/8/08	46	46	28,387	41,160
11/9/08	46	46	30,762	40,506
11/10/08	45	45	35,184	40,044
11/11/08	37	37	34,384	34,077
11/12/08	35	35	31,455	33,020
11/13/08	31	31	33,072	29,504
11/14/08	37	37	34,539	34,231
11/15/08	44	44	31,878	39,303
11/16/08	45	45	33,203	40,396
11/17/08	50	50	42,253	44,015
11/18/08	46	46	40,574	41,189
11/19/08	50	50	45,497	43,919
11/20/08	61	61	51,141	51,509
11/21/08	54	54	44,994	46,415
11/22/08	46	46	37,308	41,013
11/23/08	43	43	34,972	39,002
11/24/08	51	51	39,787	44,360
11/25/08	50	50	40,216	44,147
11/26/08	44	44	32,238	39,611

1/3/09	59	59	41,852	50,283
1/4/09	80	80	52,090	65,763
1/5/09	70	70	53,808	58,761
1/6/09	54	54	49,686	46,797
1/7/09	69	69	54,964	57,697
1/8/09	71	71	58,740	59,267
1/9/09	67	67	54,782	55,957
1/10/09	61	61	43,931	51,707
1/11/09	64	64	44,782	54,430
1/12/09	81	81	59,783	66,292
1/13/09	83	83	69,679	68,171
1/14/09	90	90	70,746	73,096
1/15/09	85	85	69,296	69,727
1/16/09	80	80	57,973	66,006
1/17/09	66	66	46,471	55,906
1/18/09	56	56	42,089	48,338
1/19/09	58	58	53,986	49,894
1/20/09	57	57	50,479	49,116
1/21/09	53	53	51,390	46,033
1/22/09	54	54	48,922	46,782
1/23/09	79	79	62,618	65,161
1/24/09	80	80	60,169	66,042
1/25/09	80	80	57,272	65,763
1/26/09	78	78	61,498	64,677
1/27/09	69	69	61,269	57,968
1/28/09	66	66	54,831	55,796
1/29/09	74	74	59,520	61,506
1/30/09	64	64	49,360	53,784
1/31/09	38	38	37,409	35,200
2/1/09	60	60	39,292	51,061
2/2/09	74	74	58,302	61,359
2/3/09	76	76	60,916	63,121
2/4/09	69	69	52,829	57,968
2/5/09	47	47	40,856	41,541
2/6/09	40	40	33,219	36,668
2/7/09	47	47	34,928	41,505
2/8/09	42	42	31,621	37,732
2/9/09	35	35	33,331	32,586
2/10/09	36	36	37,366	33,174
2/11/09	37	37	38,003	34,304
2/12/09	48	48	43,654	41,982
2/13/09	55	55	46,377	47,156
2/14/09	64	64	43,977	54,115
2/15/09	57	57	39,305	49,087
2/16/09	45	45	40,244	39,780
2/17/09	53	53	41,265	45,857
2/18/09	72	72	54,618	60,185
2/19/09	67	67	51,623	56,119
2/20/09	57	57	44,149	48,683
2/21/09	61	61	45,742	51,509
2/22/09	66	66	46,998	55,340
2/23/09	57	57	50,460	48,720
2/24/09	42	42	45,643	37,930
2/25/09	50	50	44,829	43,905
2/26/09	69	69	48,943	57,616
2/27/09	75	75	50,991	62,291
2/28/09	66	66	45,782	55,546
3/1/09	70	70	45,381	58,254
3/2/09	58	58	47,809	49,439
3/3/09	49	49	43,072	42,892
3/4/09	38	38	38,969	34,847
3/5/09	31	31	33,577	29,665

4/12/09	24	24	25,811	24,997
4/13/09	28	28	26,990	27,522
4/14/09	26	26	22,289	26,370
4/15/09	22	22	28,015	23,441
4/16/09	14	14	27,077	17,026
4/17/09	9	9	23,839	13,561
4/18/09	25	25	25,003	25,503
4/19/09	35	35	24,579	32,535
4/20/09	33	33	30,430	31,353
4/21/09	26	26	23,927	26,516
4/22/09	21	21	21,125	22,810
4/23/09	8	8	16,069	12,805
4/24/09	22	22	22,939	23,544
4/25/09	25	25	18,978	25,335
4/26/09	32	32	22,549	30,942
4/27/09	30	30	28,470	29,298
4/28/09	25	25	27,941	25,503
4/29/09	27	27	29,579	27,104
4/30/09	18	18	33,114	20,138
5/1/09	24	24	31,199	24,703
5/2/09	22	22	25,231	22,956
5/3/09	22	22	25,847	22,956
5/4/09	16	16	24,003	18,883
5/5/09	14	14	23,817	17,121
5/6/09	5	5	18,655	11,029
5/7/09	12	12	18,987	16,145
5/8/09	20	20	26,093	22,024
5/9/09	25	25	20,198	25,775
5/10/09	23	23	25,111	23,896
5/11/09	15	15	34,141	17,892
5/12/09	7	7	35,918	12,123
5/13/09	15	15	27,566	18,171
5/14/09	24	24	31,790	24,703
5/15/09	25	25	24,441	25,349
5/16/09	28	28	17,979	27,838
5/17/09	13	13	14,891	16,527
5/18/09	11	11	21,010	15,396
5/19/09	28	28	21,920	27,838
5/20/09	0	0	17,906	7,102
5/21/09	18	18	16,855	20,578
5/22/09	8	8	12,213	12,651
5/23/09	17	17	11,043	19,433
5/24/09	9	9	9,769	14,038
5/25/09	16	16	11,624	18,993
5/26/09	15	15	20,104	17,995
5/27/09	24	24	19,907	24,542
5/28/09	9	9	19,633	13,502
5/29/09	11	11	16,118	15,103
5/30/09	22	22	12,310	23,103
5/31/09	21	21	14,090	22,810
6/1/09	14	14	17,939	17,026
6/2/09	21	21	19,766	22,303
6/3/09	11	11	18,077	14,882
6/4/09	3	3	16,423	9,546
6/5/09	21	21	16,019	22,303
6/6/09	21	21	13,415	22,164
6/7/09	24	24	14,152	24,674
6/8/09	22	22	19,547	23,441
6/9/09	12	12	19,984	16,262
6/10/09	13	13	19,128	16,438
6/11/09	15	15	19,352	18,332
6/12/09	6	6	13.842	11.726

MINNESOTA ENERGY RESOURCES - NMU

Attachment 12

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

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	NM001	33,885	33,684	33,666	34,101	34,667	34,963	35,235	35,362	35,958	35,908	35,861	35,765
Residential w/o Heat	NM002	19	19	20	20	22	22	21	21	22	23	26	19
Commercial-SV	NM050/070	2,253	2,271	2,314	2,259	2,271	2,283	2,284	2,282	2,333	2,307	2,335	2,296
Commercial-LV	NM052/071	3,059	3,062	3,092	3,082	5,367	3,115	3,144	3,143	3,161	3,155	3,199	3,193
Industrial-LV	NM150	10	10	10	10	10	10	10	10	10	10	10	10
SV-Joint	NM100/101	0	0	0	0	0	0	0	0	0	0	0	0
SV-Interruptible	NM125	141	135	137	134	134	131	131	133	129	125	128	125
LV-Interruptible	NM200/201/210/211	7	7	7	8	8	8	10	8	11	11	11	12
Transport	NM500/512/501/502/522/70A/71A	6	7	7	7	7	20	12	13	9	9	9	9
Transport	NM503/511/504/506/508/74L/80A	10	10	10	11	10	14	8	8	8	8	8	7
Transport	NM516	1	1	1	5	1	1	1	1	0	1	1	0
Transport	NM507/513/514	9	19	9	9	9	9	12	9	8	9	16	10
Transport	NM72A/73A	0	0	0	0	0	0	0	0	0	0	0	0
Transport	NM510	0	0	0	0	0	0	0	0	0	0	0	0
Transport	NM515	0	0	0	0	0	0	0	0	0	0	0	0
Total		39,400	39,225	39,273	39,646	42,506	40,576	40,868	40,990	41,649	41,566	41,604	41,446

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Projected Fixed Cost - November 2009 through March 2010

Fixed Price WACOG

[TRADE SECRET DATA BEGINS

Projected Fixed Cost - November 2009 through March 2010

Projected Fixed Cost - November 2009 through March 2010

Projected Fixed Cost - November 2009 through March 2010

TRADE DATA SECRET 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 DATA SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

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

Call/Put Options WACOG

[TRADE SECRET DATA BEGINS

Contract = 10,000

TRADE DATA SECRET END

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED