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November 1, 2011

VIA ELECTRONIC FILING

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–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 Attachments 8 and 9 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

November 1, 2011

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
3460 Technology Drive NW
Rochester, MN 55901
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

Ellen Anderson	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	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	)	

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-PNG's 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, 2011.

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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	)	

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-PNG's 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, 2011.

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 1, 2011
Proposed Effective Date: November 1, 2011

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
3460 Technology Drive NW
Rochester, MN 55901
(507) 529-5100

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

DATED: November 1, 2011

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

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
J. Dennis O'Brien	Commissioner
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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
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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-PNG's 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, 2011.

[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 2011-2012 heating season for its Viking customers in a separate docket, and requests approval of a demand entitlement change on the GLGT system in a separate docket

II. DISCUSSION

A. MERC's PNG-NNG Design Day Requirements

MERC's 2010-2011 NNG design day requirements increased 16,584 Mcf (or approximately 8.52 percent) from 194,598 Mcf to 211,182 Mcf.

Table 1: MERC's Proposed NNG Reserve Margins
For the 2011-2012 Heating Season
PNG/NMU

	Reserve Margin 2011-2012 Heating Season	Reserve Margin 2010-2011 Heating Season	Change
NNG Zone EF	4.69%	19.92%	15.23%

As shown in Table 1, MERC's proposed system wide reserve margin, Zone EF for the 2011-2012 heating season is positive.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for Northern Natural Gas (NNG), which includes PNG and NMU is 234,960 Dth as calculated in Attachment 5 and Attachment 7 under the NNG Entitlement Allocation.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity on Northern Natural Gas (NNG), which includes PNG and NMU is 245,985 Dth as calculated in Attachment 5 and Attachment 7 under the NNG Entitlement Allocation. The difference between the total Design Day requirement and total Design Day capacity results in a 4.69% positive reserve margin.

Demand Entitlement decreased primarily due to the elimination of the LSP Peaking Service (25,951 Dth). NNG, Bison and NBPL capacity is allocated between

PNG and NMU based on a prorated share based on design day numbers. PNG prorated percentage of NNG capacity is approximately 89.88% and NMU's prorated percentage is approximately 10.12%. Due to the proration, there was an increase of 1,615 Dth in PNG-NNG winter capacity, 351 Dth increase in PNG-NNG Bison and NBPL capacity. In April, 2011, NNG sold a line that served the City of Ortonville to Northwestern Energy. Since Ortonville is a PNG-NNG customer, this capacity (910 Dth) is directly assigned to PNG-NNG. As stated previously, MERC terminated the LSP Peaking Service provision with LS Power. In lieu of the call option, MERC replaced that peaking capability with a physical delivered Gas Daily Daily call option (12,500 Dth). MERC allocated the volume/cost on same prorated percentages as capacity allocated for NNG capacity. Please see Attachments 5 and 8 for calculated volumes by month.

B. <u>Forecast Methodology for MERC Demand Entitlement Nov. 1, 2010</u>

<u>Peakday</u>

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 <u>two service areas:</u>

1. PNG - Peoples Natural Gas (company – approximately 170,000 customers)

2. NMU - Northern Minn Utility (company – approximately 40,000 customers)

Which are served by <u>four pipelines:</u>

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 PGA):

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 the following weather stations:

1. International Falls
2. Bemidji
3. Cloquet
4. Fargo
5. Minneapolis
6. Rochester
7. Worthington
8. Ortonville

For analytical purposes, data is subdivided, analyzed and regressed by the following 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
7a	PNG-NNG – All except Ortonville	PNG-NNG	Minneapolis, Rochester, Cloquet & Worthington
7b	PNG-NNG – Ortonville Only	PNG-NNG	Ortonville
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.

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 **<u>Data Preparation</u>** 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 each of the 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 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
Worthington	1/18/1996	-8	32	73	96
Ortonville	1/14/2009	-21	11	86	96

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 an ideal world, the Team would have also had daily telemetered data from each interruptible, transportation, and joint interruptible customer mapped to each of the 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, resulting 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 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

[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 the 9am to 9am gas day.

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).

III. Volume Risk Adjustments

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, resulting in billing cycle estimates and reversals), and other potential errors into their volumes.

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

[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.

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 1st Revised 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 the prior winter that showed the volume that each customer has selected to receive as firm service from MERC each month. Based on 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 the daily firm capacity volumes were summed by month for each demand area. The total volumes 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 the last three winters and needed to be adjusted to properly forecast the next year. The Revenue Forecasting Department provided a growth rate for each demand area, which were then applied to the adjusted regression results.

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

<u>NMU-GLGT</u> = Paper Mills

<u>NMU-VGT</u> = Lamb Weston

<u>PNG-NNG</u> = Taconites / Direct Connects

<u>PNG-NNG</u> = OSEU (End Users)

B. Daily Firm Capacity

<u>PNG-VGT</u>

<u>PNG-GLGT</u>

<u>PNG-NNG</u>

-

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 the 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.

Average Customer Counts

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

C. <u>MERC's Specific PNG Proposed Northern System Demand-Related Changes</u>

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-PNG's 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 a decrease of 12,191 Mcf/day in total heating season. 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	529	Mcf/Day
TF5	226	Mcf/Day
TFX12	227	Mcf/Day
TFX5	633	Mcf/Day
Bison *	351	Mcf/Day
NBPL *	351	Mcf/Day
Northwestern Energy	910	Mcf/Day
NNG Zone Delivery Call Option	11,235	
LS Power	(25,951)	Mcf/Day
Total Overall Change	(12,191)	Mcf/Day

* Volumes not part of heating season volumes

MERC contracted for capacity on Bison Pipeline for 50,000 Dth/day which went into service on January 14, 2011. The contracted capacity with Northern Border Pipeline (NBPL) went into effect at the in-service of Bison. The PNG-NNG allocated share of this capacity is 44,940 Dth/day. This capacity does not add any incremental capacity but is utilized to deliver Rockies supply to PNG-NNG and NMU-NNG customers at Northern Border Pipeline (NBPL) interconnects with NNG.

2. Other Demand Entitlement Changes

As shown in the Attachment 10, MERC-PNG-NNG proposes an increase in TFX Apr and TFX Oct and an increase of Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability.

D. Financial Units and Premiums

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2011/2012 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 $1,227,613 for the 2011/2012 winter. Please see Attachment 8.

iii. MERC entered into 479 contracts (10,000/contract) or 4,790,000. Total premium per contract is approximately $0.2563. 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 entered into 208 futures contracts (10,000/contract) or 2,080,000.

vii. 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 futures contracts), 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. Gas Supply.

The PNG-NNG 2011-2012 Winter Portfolio Plan - Minnesota Energy Resources Corporation for NNG gas supply purchases for the Hedging Plan is in Attachment 9, page 2.

F. Price Volatility

MERC hedging strategy as described in section 2.(D.)(vii.) 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 futures contracts. MERC is projecting the weighted average cost of gas (WACOG) for futures contracts of natural gas to be approximately $4.5094. Please see Attachment 15, page 1 of 3. MERC is projecting the NNG Storage WACOG for PNG-NNG to be approximately $4.1398. 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 $4.6295, 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 $4.32 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $4.6295 strike price plus the physical index basis spread. If the NYMEX prices are below the average $4.6295 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 its monthly PGA effective November 1, 2011. 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.

H. Impacts of Telemetry

Based on the requirement that all interruptible and transportation customers on MERC's system must have telemetry, this has led to some customers switching from interruptible to firm. On the PNG-NNG, there have been sixty-five (65) customers that switched from interruptible to firm service. The switching occurred between February 16, 2011 through August 12, 2011. Since MERC's peak day analysis is based on December through February volumes for the three previous winters, for the most part, these volumes aren't represented in MERC's design day analysis. MERC projected the impact on firm requirements by projecting peak day volumes for the customers that switched. The projected peak day was calculated by taking actual peak day and dividing the volume by twenty (20). MERC is projecting an increase in design day of 7,707 Mcf. Assuming the projected peak day is accurate, MERC would still have adequate firm entitlement to meet a peak day.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2011. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2011

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)

Amber S. Lee hereby certifies that on the 1st day of November, 2011, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of the Petition on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

/s/ Amber S. Lee
Amber S. Lee

Subscribed and sworn to before me
this 1st day of November, 2011.

/s/ Sara Garcia
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-PNG

Demand Entitlement Schedules - NNG

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2011
NNG

Design Day Requirement		211,182
Total Peak Day Entitlement		221,436
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 20)	163,142
Firm Annual Throughput - Minnesota		19,834,162
No. of Firm Customers		157,442
Department Load Factor Calculation		33.31%

MINNESOTA ENERGY RESOURCES - PNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2011

NNG

Pipeline Group	Nov10-Mar 11 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	Nov10-Mar 11 Avg. Customer Growth	Total *
PEAK										
PNG	157,442	157,442	99	28,470	2,185	245,374	35,659	209,715	0.70%	211,182
Total	157,442	157,442								211,182
OFF PEAK										
PNG	157,442	157,442	55	28,470	2,185	148,662	18,728	129,934	0.70%	130,844
Total	157,442	157,442								130,844

* 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% confiden 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, 2011

NNG

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
11/12	157,442	211,182	1.34
10/11	158,298	194,598	1.23
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

MINNESOTA ENERGY RESOURCES - PNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2012

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	5,507,475	14,326,687	19,834,162
SVI	595,326	1,140,941	1,736,267
SVJ	0	0	0
LVI	215,696	378,016	593,712
LVJ	0	0	0
SLV	0	0	0
Total	6,318,497	15,845,644	22,164,141

MINNESOTA ENERGY RESOURCES - PNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2011

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
TF-12 Base & Variable	67,165	529	67,694
TF5	28,785	226	29,011
TFX - 12	28,802	227	29,029
TFX - 5	80,424	633	81,057
TFX- (Apr) Offpeak*	1,784	14	1,798
TFX- (Oct) Offpeak*	1,784	14	1,798
Bison	44,589	351	44,940
NBPL	44,589	351	44,940
Northwest Gas (Windom)	2,500	0	2,500
Northwestern Energy (Ortonville)	0	910	910
NNG Zone Delivery Call Option	0	11,235	11,235
LSP Peaking Service	25,951	(25,951)	0
Heating Season Total	**233,627**	**(12,191)**	**221,436**
Non-Heating Season Total	100,251	1,679	101,930
Heating Season Forecasted Design Day-Adjusted	194,598	16,584	211,182
Non-Heating Season Forecasted Design Day	119,468	11,376	130,844
Heating Season Capacity Surplus/Shortage	39,029	(28,775)	10,254
Non-Heating Season Capacity Surplus/Shortage	(19,217)	(9,697)	(28,914)

*Not included in Heating Season Total entitlement

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2011

NNG

All costs in $/MMBtu	Last Base Cost of Gas G007, G011/ MR10-978* Feb. 11	Last Demand Change G011-M-09- Oct 09	Last Demand Change G011-M-10- Oct. 10	Most Recent PGA** Oct. 2011	Current Proposal Effective Nov.1,2011	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 Residential: Avg. Annual Use:		86		Mcf					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	($1.5029)	$0.2960	5.79%	$0.2314
Demand Cost	$1.6893	$1.0883	$1.0362	$1.6103	$1.7414	$0.0521	$0.7052	8.14%	$0.1311
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.1914	$6.4545	$6.7394	$7.3781	$7.7406	($1.4508)	$1.0012	4.91%	$0.3625
Avg Annual Cost	$790.46	$555.09	$579.59	$634.52	$665.69	($124.77)	$86.10	4.91%	$31.17
Effect of proposed commodity change on average annual bills:									$19.90
Effect of proposed demand change on average annual bills:									$11.27
2) Small Vol. Interruptible: Avg. Annual Use:		4,371		Mcf					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	($1.5029)	$0.2960	5.79%	$0.2314
Demand Cost	$0.0000								
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.8956	$4.9833	$5.0967	$5.1613	$5.3927	($1.5029)	$0.2960	4.48%	$0.2314
Avg Annual Cost	$30,140.67	$21,782.00	$22,277.68	$22,560.04	$23,571.45	($6,569.22)	$1,293.77	4.48%	$1,011.41
Effect of proposed commodity change on average annual bills :									$1,011.41
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		11,202		Mcf					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	($1.5029)	$0.2960	5.79%	$0.2314
Demand Cost									
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.0523	$4.0991	$4.2534	$4.3180	$4.5494	($1.5029)	$0.2960	5.36%	$0.2314
Avg Annual Cost	$67,797.86	$45,918.12	$47,646.59	$48,370.24	$50,962.27	($16,835.59)	$3,315.69	5.36%	$2,592.04
Effect of proposed commodity change on average annual bills:									$2,592.04
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		4,800		Mcf					
		25		Mcf					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	($1.5029)	$0.2960	5.79%	$0.2314
Demand Cost	$19.6334	$10.3925	$9.3592	$10.7144	$10.8163	($8.8171)	$1.4571	0.95%	$0.1019
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.8956	$4.9833	$5.0967	$5.1613	$5.3927	($1.5029)	$0.2960	4.48%	$0.2314
Total Demand Cost	$21.4334	$12.4649	$11.1592	$12.5144	$12.6163	($8.8171)	$1.4571	0.81%	$0.1019
Avg Annual Cost	$33,634.72	$24,231.46	$24,743.14	$25,087.10	$26,200.32	($7,434.39)	$1,457.18	4.44%	$1,113.22
Effect of proposed commodity change on average annual bills:									$1,110.67
Effect of proposed demand change on average annual bills:									$2.55
5) Large Vol. Firm: Avg. Annual Use:		14,841		Mcf					
		75		Mcf					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	($1.5029)	$0.2960	5.79%	$0.2314
Demand Cost	$19.6334	$10.3925	$9.3592	$10.7144	$10.8163	($8.8171)	$1.4571	0.95%	$0.1019
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$0.1400	$1.6579	$1.4000	$1.4000	$1.4000	$1.2600	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.0523	$4.0991	$4.2534	$4.3180	$4.5494	($1.5029)	$0.2960	5.36%	$0.2314
Total Demand Cost	$19.7734	$12.0504	$10.7592	$12.1144	$12.2163	($7.5571)	$1.4571	0.84%	$0.1019
Avg Annual Cost	$91,305.19	$61,738.52	$63,931.65	$64,992.02	$68,433.73	($7,402.89)	$4,502.08	5.30%	$3,441.71
Effect of proposed commodity change on average annual bills:									$3,434.07
Effect of proposed demand change on average annual bills:									$7.64

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-11-793
*As submitted in Docket No. G007,011/MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781

MINNESOTA ENERGY RESOURCES - PNG
RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2011

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE 01-Nov-11

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$5.6830	$10.2300	$7.5776	$0.0000	$7.5776
TF-12V	$5.6830	$13.8660	$9.0926	$0.0000	$9.0926
TF-5		$15.1530	$15.1530	$0.0000	$15.1530
TFX	$5.6830	$15.1530	$9.6288	$0.0000	$9.6288
TF-12B Discount	$5.6830	$7.6000	$6.4818	$0.0000	$6.4818
Gas Cost					$4.2174

V. ANNUAL SALES -- RATE CASE 2008 TOTAL 213,137,630

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-11

			Contract #(s)		Months				Rate/CCF
A. GS		TF12B (Max Rate)	112495	37,959	12	$7.5776	=	$3,451,657	$0.01785
		TF12V (Max Rate)	112495	25,298	12	$9.0926	=	$2,760,295	$0.01428
		TF5 (Max Rate)	112495	28,248	5	$15.1530	=	$2,140,210	$0.01107
		TF12B (Discount-Winter)	112495	4,437	12	$6.4818	=	$345,117	$0.00179
		TF5 (Discount-Winter)	112495	763	5	$7.6000	=	$28,994	$0.00015
		TFX5 (Discount)	112561	5,393	5	$4.5600	=	$122,960	$0.00064
		TFX12 (Max Rate)	112486	9,727	12	$9.6288	=	$1,123,912	$0.00581
		TFX Apr (Max Rate)	112486	1,798	1	$5.6830	=	$10,218	$0.00005
		TFX Oct (Max Rate)	112486	1,798	1	$5.6830	=	$10,218	$0.00005
		TFX5 (Max Rate)	112486	51,383	5	$15.1530	=	$3,893,033	$0.02014
		TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00035
		TFX12 (Discount)	111866	1,153	12	$4.8640	=	$67,298	$0.00035
		TFX12 (Discount)	111866	7,434	12	$5.4720	=	$488,146	$0.00253
		TFX12 (Discount)	111866	10,715	12	$2.2192	=	$285,345	$0.00148
		TFX5 (Discount)	111866	341	5	$4.8640	=	$8,293	$0.00004
		TFX5 (Discount)	111866	2,198	5	$5.4720	=	$60,137	$0.00031
		TFX5 (Discount)	111866	19,943	5	$15.1392	=	$1,509,605	$0.00781
		SMS	112521	20,385	12	$2.1800	=	$533,272	$0.00276
		Bison	FT0003	44,940	12	$17.4800	=	$9,426,614	$0.04876
		NBPL	T8673F	44,940	12	$6.9920	=	$3,770,646	$0.01950
		LS Power		0	0	$4.3463	=	$0	$0.00000
		Windom		2,500	12	$0.0000	=	$0	$0.00000
		Ortonville		910	12	$8.0000	=	$87,360	$0.00045
		NNG Zone GDD Call Option		11,235	3	$0.9100	=	$30,672	$0.00016
	FDD:	Storage Reservation	118657	67,803	12	$1.7140	=	$1,394,572	$0.00721
		Storage Cycle Volume	118657	781,834	5	$0.3567	=	$1,394,401	$0.00721
		Storage Reservation	118657	4,988	12	$3.3157	=	$198,465	$0.00103
		Storage Cycle Volume	118657	57,523	5	$0.6901	=	$198,483	$0.00103
		Storage Reservation	122800	6,236	12	$1.7140	=	$128,262	$0.00066
		Storage Cycle Volume	122800	71,904	5	$0.3567	=	$128,241	$0.00066
		Total Demand Cost						$33,664,825	$0.17414
		Rate Case 2008 volume in Ccf						193,321,000	
		GS-1 Demand Current Cost of Gas/Ccf							**$0.17414**
		GS-1 Commodity Current Cost of Gas/Ccf							**$0.42246**
		Total GS-1 Current Cost of Gas/Ccf							**$0.59660**

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	21,313,763	x	$4.2174	$89,888,664.08	213,137,630	$0.42174
Call Option Premium				$ 153,257	213,137,630	$0.00072
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$ 90,041,921	213,137,630	$0.42246
CURRENT FIRM TRANSPORTATION COST OF GAS (CCF)						$0.75776

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C) $1.08163 $1.08163

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2011

NNG

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	37,959	112495	12	$7.5776	=	$3,451,657	$0.11090
TF12V (Max Rate)	25,298	112495	12	$9.0926	=	$2,760,295	$0.08869
TF5 (Max Rate)	28,248	112495	5	$15.1530	=	$2,140,210	$0.06876
TF12B (Discount-Winter)	4,437	112495	12	$6.4818	=	$345,117	$0.01109
TF5 (Discount-Winter)	763	112495	5	$7.6000	=	$28,994	$0.00093
TFX5 (Discount)	5,393	112561	5	$4.5600	=	$122,960	$0.00395
TFX12 (Max Rate)	9,727	112486	12	$9.6288	=	$1,123,912	$0.03611
TFX Apr (Max Rate)	1,798	112486	1	$5.6830	=	$10,218	$0.00033
TFX Oct (Max Rate)	1,798	112486	1	$5.6830	=	$10,218	$0.00033
TFX5 (Max Rate)	51,383	112486	5	$15.1530	=	$3,893,033	$0.12508
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00220
TFX12 (Discount)	1,153	111866	12	$4.8640	=	$67,298	$0.00216
TFX12 (Discount)	7,434	111866	12	$5.4720	=	$488,146	$0.01568
TFX12 (Discount)	10,715	111866	12	$2.2192	=	$285,345	$0.00917
TFX5 (Discount)	341	111866	5	$4.8640	=	$8,293	$0.00027
TFX5 (Discount)	2,198	111866	5	$5.4720	=	$60,137	$0.00193
TFX5 (Discount)	19,943	111866	5	$15.1392	=	$1,509,605	$0.04850
SMS	20,385	112521	12	$2.1800	=	$533,272	$0.01713
Bison	44,940	FT0003	12.0	$17.4800	=	$9,426,614	$0.30287
NBPL	44,940	T8673F	12.0	$6.9920	=	$3,770,646	$0.12115
LS Power	0		0	$4.3463	=	$0	$0.00000
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00281
NNG Zone GDD Call Opti	11,235		3	$0.9100	=	$30,672	$0.00099
Storage Reservation	67,803	118657	12	$1.7140	=	$1,394,572	$0.04481
Storage Cycle Volume	781,834	118657	5	$0.3567	=	$1,394,401	$0.04480
Storage Reservation	4,988	118657	12	$3.3157	=	$198,465	$0.00638
Storage Cycle Volume	57,523	118657	5	$0.6901	=	$198,483	$0.00638
Storage Reservation	6,236	122800	12	$1.7140	=	$128,262	$0.00412
Storage Cycle Volume	71,904	122800	5	$0.3567	=	$128,241	$0.00412
				TOTAL		$33,664,826	
				Annualized Entitlement		31,124,220	
				Demand Component		$1.08163	$1.08163

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, 2011

NNG

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct.08	Demand Change G011-M-09-Oct.09	Last Demand Change G011-M-10-Oct.10	Most Recent PGA Oct. 2011	Current Proposal Effective Nov.1,2011	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 Residential: Avg. Annual	**86**			**Mcf**					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	($1.3414)	$0.4575	9.84%	$0.3929
Demand Cost	$1.6893	$1.0883	$1.0362	$1.6103	$1.5572	($0.1321)	$0.5210	-3.30%	($0.0531)
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.1914	$6.4545	$6.7394	$7.3781	$7.7179	($1.4735)	$0.9785	4.61%	$0.3398
Avg Annual Cost	$790.46	$555.09	$579.59	$634.52	$663.74	($126.72)	$84.15	4.61%	$29.22
Effect of proposed commodity change on average annual bills:									$33.79
Effect of proposed demand change on average annual bills:									($4.56)
2) Small Vol. Interruptible: Avg. Annual Use:	**4,371**			**Mcf**					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	($1.3414)	$0.4575	9.84%	$0.3929
Demand Cost									
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.8956	$4.9833	$5.0967	$5.1613	$5.5542	($1.3414)	$0.4575	7.61%	$0.3929
Avg Annual Cost	$30,140.67	$21,782.00	$22,277.68	$22,560.04	$24,277.42	($5,863.25)	$1,999.74	7.61%	$1,717.38
Effect of proposed commodity change on average annual bills:									$1,717.38
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:	**11,202**			**Mcf**					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	($1.3414)	$0.4575	9.84%	$0.3929
Demand Cost									
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.0523	$4.0991	$4.2534	$4.3180	$4.7109	($1.3414)	$0.4575	9.10%	$0.3929
Avg Annual Cost	$67,797.86	$45,918.12	$47,646.59	$48,370.24	$52,771.53	($15,026.34)	$5,124.94	9.10%	$4,401.29
Effect of proposed commodity change on average annual bills:									$4,401.29
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:	**4,800**			**Mcf**					
	25			**Mcf**					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	($1.3414)	$0.4575	9.84%	$0.3929
Demand Cost	$19.6334	$10.3925	$9.3592	$10.7144	$16.9273	($2.7061)	$7.5681	57.99%	$6.2129
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.8956	$4.9833	$5.0967	$5.1613	$5.5542	($1.3414)	$0.4575	7.61%	$0.3929
Total Demand Cost	$21.4334	$12.4649	$11.1592	$12.5144	$18.7273	($2.7061)	$7.5681	49.65%	$6.2129
Avg Annual Cost	$33,634.72	$24,231.46	$24,743.14	$25,087.10	$27,128.35	($6,506.36)	$2,385.21	8.14%	$2,041.25
Effect of proposed commodity change on average annual bills:									$1,885.93
Effect of proposed demand change on average annual bills:									$155.32
5) Large Vol. Firm: Avg. Annual Use:	**14,841**			**Mcf**					
	75			**Mcf**					
Commodity Cost	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	($1.3414)	$0.4575	9.84%	$0.3929
Demand Cost	$19.6334	$10.3925	$9.3592	$10.7144	$16.9273	($2.7061)	$7.5681	57.99%	$6.2129
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$0.1400	$1.6579	$1.4000	$1.4000	$1.4000	$1.2600	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.0523	$4.0991	$4.2534	$4.3180	$4.7109	($1.3414)	$0.4575	9.10%	$0.3929
Total Demand Cost	$19.7734	$12.0504	$10.7592	$12.1144	$18.3273	($1.4461)	$7.5681	51.29%	$6.2129
Avg Annual Cost	$91,305.19	$61,738.52	$63,931.65	$64,992.02	$71,289.05	($6,474.86)	$7,357.40	9.69%	$6,297.03
Effect of proposed commodity change on average annual bills:									$5,831.06
Effect of proposed demand change on average annual bills:									$465.97

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 Co mmodity costs

NOVEMBER 1, 2011

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE 01-Nov-10

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$5.6830	$10.2300	$7.5776	$0.0000	$7.5776
TF-12V	$5.6830	$13.8660	$9.0926	$0.0000	$9.0926
TF-5		$15.1530	$15.1530	$0.0000	$15.1530
TFX	$5.6830	$15.1530	$9.6288	$0.0000	$9.6288
TF-12B Discount	$5.6830	$7.6000	$6.4818	$0.0000	$6.4818
Gas Cost					$4.2174

V. ANNUAL SALES -- RATE CASE 2008 TOTAL 213,137,630

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-10

		Contract #(s)		Months				Rate/CCF
A. GS	TF12B (Max Rate)	112495	37,959	12	$7.5776	=	$3,451,657	$0.01785
	TF12V (Max Rate)	112495	25,298	12	$9.0926	=	$2,760,295	$0.01428
	TF5 (Max Rate)	112495	28,248	5	$15.1530	=	$2,140,210	$0.01107
	TF12B (Discount-Winter)	112495	4,437	12	$6.4818	=	$345,117	$0.00179
	TF5 (Discount-Winter)	112496	763	5	$7.6000	=	$28,994	$0.00015
	TFX5 (Discount)	112561	5,393	5	$4.5600	=	$122,960	$0.00064
	TFX12 (Max Rate)	112486	9,727	12	$9.6288	=	$1,123,912	$0.00581
	TFX Apr (Max Rate)	112486	1,798	1	$5.6830	=	$10,218	$0.00005
	TFX Oct (Max Rate)	112486	1,798	1	$5.6830	=	$10,218	$0.00005
	TFX5 (Max Rate)	112486	51,383	5	$15.1530	=	$3,893,033	$0.02014
	TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00035
	TFX12 (Discount)	111866	1,153	12	$4.8640	=	$67,298	$0.00035
	TFX12 (Discount)	111866	7,434	12	$5.4720	=	$488,146	$0.00253
	TFX12 (Discount)	111866	10,715	12	$2.2192	=	$285,345	$0.00148
	TFX5 (Discount)	111866	341	5	$4.8640	=	$8,293	$0.00004
	TFX5 (Discount)	111866	2,198	5	$5.4720	=	$60,137	$0.00031
	TFX5 (Discount)	111866	19,943	5	$15.1392	=	$1,509,605	$0.00781
	SMS	112521	20,385	12	$2.1800	=	$533,272	$0.00276
	Bison	FT0003	44,940	12.0	$17.4800	=	$9,426,614	$0.04876
	NBPL	T8673F	44,940	12.0	$6.9920	=	$3,770,646	$0.01950
	LS Power		0	0	$4.3463	=	$0	$0.00000
	Windom		2,500	12	$0.0000	=	$0	$0.00000
	Ortonville		910	12	$8.0000	=	$87,360	$0.00045
	NNG Zone GDD Call Option		11,235	3	$0.9100	=	$30,672	$0.00016
	Total Demand Cost						$30,222,402	**$0.15572**
	Rate Case 2008 volume in Ccf						193,321,000	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.15633**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.43861**
	Total GS-1 Current Cost of Gas/Ccf							**$0.59494**

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

			Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Contract Costs	Rate ($/therm)
FDD:	FDD - Reservation	118657	67,803	12	$1.7140	=	$1,394,572	$0.00654
	FDD - Storage Cycle	118657	781,834	5	$0.3567	=	$1,394,401	$0.00654
	FDD - Reservation	118657	4,988	12	$3.3157	=	$198,465	$0.00093
	FDD - Storage Cycle	118657	57,523	5	$0.6901	=	$198,483	$0.00093
	FDD - Reservation	121292	6,236	12	$1.7140	=	$128,262	$0.00060
	FDD - Storage Cycle	121292	71,904	5	$0.3567	=	$128,241	$0.00060
	Firm Deferred Delivery Storage Contracts						$3,442,424	$0.01615

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	21,313,763	x	$4.2174	$89,888,664	213,137,630	$0.42174
Call Option Premium				$153,257	213,137,630	$0.00072
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$93,484,345	213,137,630	**$0.43861**
CURRENT FIRM TRANSPORTATION COST OF GAS (CCF)						$0.75776

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C) $1.69273 $1.69273

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, 2011

NNG

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	37,959	112495	12	$7.5776	=	$3,451,657	$0.19332
TF12V (Max Rate)	25,298	112495	12	$9.0926	=	$2,760,295	$0.15460
TF5 (Max Rate)	28,248	112495	5	$15.1530	=	$2,140,210	$0.11987
TF12B (Discount-Winter)	4,437	112495	12	$6.4818	=	$345,117	$0.01933
TF5 (Discount-Winter)	763	112495	5	$7.6000	=	$28,994	$0.00162
TFX5 (Discount)	5,393	112561	5	$4.5600	=	$122,960	$0.00689
TFX12 (Max Rate)	9,727	112486	12	$9.6288	=	$1,123,912	$0.06295
TFX Apr (Max Rate)	1,798	112486	1	$5.6830	=	$10,218	$0.00057
TFX Oct (Max Rate)	1,798	112486	1	$5.6830	=	$10,218	$0.00057
TFX5 (Max Rate)	51,383	112486	5	$15.1530	=	$3,893,033	$0.21804
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00383
TFX12 (Discount)	1,153	111866	12	$4.8640	=	$67,298	$0.00377
TFX12 (Discount)	7,434	111866	12	$5.4720	=	$488,146	$0.02734
TFX12 (Discount)	10,715	111866	12	$2.2192	=	$285,345	$0.01598
TFX5 (Discount)	341	111866	5	$4.8640	=	$8,293	$0.00046
TFX5 (Discount)	2,198	111866	5	$5.4720	=	$60,137	$0.00337
TFX5 (Discount)	19,943	111866	5	$15.1392	=	$1,509,605	$0.08455
SMS	20,385	112521	12	$2.1800	=	$533,272	$0.02987
Bison	44,940	FT0003	12.0	$17.4800	=	$9,426,614	$0.52798
NBPL	44,940	T8673F	12.0	$6.9920	=	$3,770,646	$0.21119
LS Power	0		0	$4.3463	=	$0	$0.00000
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00489
NNG Zone GDD Call Option	11,235		3	$0.9100	=	$30,672	$0.00172
Storage Reservation	67,803	118657	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	781,834	118657	0	$0.3567	=	$0	$0.00000
Storage Reservation	4,988	118657	0	$3.3157	=	$0	$0.00000
Storage Cycle Volume	57,523	118657	0	$0.6901	=	$0	$0.00000
Storage Reservation	6,236	122800	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	71,904	122800	0	$0.3567	=	$0	$0.00000
				TOTAL		$30,222,403	
				Annualized Entitlement		17,854,270	
				Demand Component		$1.69273	$1.69273

MINNESOTA ENERGY RESOURCES

NNG Entitlement Allocation

Heating Season 2011-2012

	Total Entitlement Levels	PNG GS	NMU GS	Total
1 Design Day	**234,960**	211,182	23,778	**234,960**
2 Customer Requirements moving to Transport	-	-	-	-
3 Adjusted Design Day	**235,055**	211,182	23,778	234,960
		89.88%	10.12%	**100.00%**
5 Total Design Day Capacity	**232,575**	209,291	23,284	**232,575**
6 Less: Windom	(2,500)	(2,500)	-	**(2,500)**
7 Less: Northwestern Energy	(910)	(910)	-	**(910)**
8 Less: LS Power	0	-	-	-
9 Less: Chisago Delivery to Viking	0	-	-	-
10 Less: Contract Demand Units	(95)	(95)	-	**(95)**
	229,070	205,786	23,284	**229,070**
Direct Assigned Entitlement				
11 TF12B (112495)	47,170	42,396	4,774	**47,170**
12 TF12V (112495)	28,146	25,298	2,848	**28,146**
13 TF5 (112495)	32,278	29,011	3,267	**32,278**
14 TFX12 (112486)	10,822	9,727	1,095	**10,822**
15 TFX April Only (112486)	2,000	1,798	202	**2,000**
16 TFX October Only (112486)	2,000	1,798	202	**2,000**
17 TFX5 (112486)	59,171	53,183	5,988	**59,171**
18 TFX12 (111866)	21,475	19,302	2,173	**21,475**
19 TFX5 (111866)	25,013	22,482	2,531	**25,013**
20 TFX5 (112561)	6,000	5,393	607	**6,000**
21 Bison (FT 0003) *	50,000	44,940	5,060	**50,000**
22 NBPL (T6873F) *	50,000	44,940	5,060	**50,000**
23 Total Winter Allocated Entitlement	230,075	206,791	23,284	**230,075**
24 Northwest Gas (Windom)	2,500	2,500	-	**2,500**
25 Northwestern Energy (Ortonville)	910	910	-	**910**
26 NNG Zone Delivery Call Option	12,500	11,235	1,265	**12,500**
27 LS Power	0	-	-	-
28 Total Design Day Capacity	**245,985**	**221,436**	**24,549**	**245,985**
29 Contract Demand				-
30 Total Design Day Capacity	**245,985**	221,436	24,549	**245,985**
		90.02%	9.98%	**100.00%**
Other Entitlements not included in Peak Day Deliverability: allocation based on design day % on line 19				
31 Storage				
32 Storage MSQ - 118657	4,669,321	4,196,785	472,536	**4,669,321**
33 Storage MSQ - 121292	400,000	359,520	40,480	**400,000**
34 SMS	22,680	20,385	2,295	**22,680**
35 Total Entitlement	245,985	221,436	24,549	**245,985**
36 Design Day	235,055	211,182	23,778	**234,960**
37 Reserve Margin	10,930	10,254	771	**11,025**
	4.65%	4.86%	3.24%	4.69%

* Bison/NBPL does not add incremental capacity but is utilized to deliver Rockies supply to NNG. Volume is not included in Total Design Day capacity.

MINNESOTA ENERGY RESOURCES - PNG

CALCULATION OF DESIGN DAY REQUIREMENTS

2011-2012

State	1/20 Design DDD	10/11 Customer Counts*	Regression Factors Intercept	Slope	Regression Total	Adjustment Total *	1/20 Requirements Regression Load	Nov10-Mar11 Customer Growth	Total
MERC - Peak Day									
PNG	99	157,442	28,470	2,185	245,374	35,659	209,715	0.70%	211,182
NMU	103	17,799	3,244	226	26,534	2,732	23,802	-0.10%	23,778
TOTAL		**175,241**	**31,714**	**2,411**	**271,908**	**38,391**	**233,517**		**234,960**

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2011-2012 VS. 2010-2011

	2011-2012 Proposed				2010-2011				Difference			
	NNG Winter	NNG PNG	NNG NMU	NNG Total	NNG Winter	NNG PNG	NNG NMU	NNG Total	Winter	PNG	NMU	Total
TF12(base)	47,170	42,396	4,774	47,170	39,107	34,875	4,232	39,107	8,063	7,521	542	8,063
TF12(variable)	28,146	25,298	2,848	28,146	36,209	32,290	3,919	36,209	(8,063)	(6,992)	#####	(8,063)
TF12	75,316	67,694	7,622	75,316	75,316	67,165	8,151	75,316	-	529	(529)	-
Peak Capacity	-			-	-			-	-			-
TF5	32,278	29,011	3,267	32,278	32,278	28,785	3,493	32,278	-	226	(226)	-
TF Total	107,594	96,705	10,889	107,594	107,594	95,950	#####	107,594	-	755	(755)	-
TFX12	32,297	29,029	3,268	32,297	32,297	28,802	3,495	32,297	-	227	(227)	0
TFX5	90,184	81,057	9,127	90,184	90,184	80,424	9,760	90,184	-	633	(633)	(0)
TFX Total	122,481	110,086	12,395	122,481	122,481	######	#####	122,481	-	860	(860)	(0)
NNG Total	230,075	206,791	23,284	230,075	230,075	######	#####	230,075	-	1,615	#####	(0)
Bison	50,000	44,940	5,060	50,000	50,000	44,589	5,411	50,000	-	351	(351)	-
NBPL	50,000	44,940	5,060	50,000	50,000	44,589	5,411	50,000	-	351	(351)	-
Windom	2,500	2,500	-	2,500	2,500	2,500	-	2,500	-	-	-	-
Ortonville	910	910	-	910	-	-	-	-	910	910	-	
NNG Zone GDD Call Option	12,500	11,235	1,265	12,500	-	-	-	-	12,500	11,235	1,265	
LSP Peaking	-	-	-	-	29,100	25,951	3,149	29,100	(29,100)	(25,951)	#####	(29,100)
Total	245,985	221,436	24,549	245,985	261,675	######	#####	261,675	(15,690)	(12,191)	#####	(29,100)

NNG-Total	EF	TOTAL
Design Day	234,960	234,960
Capacity	245,985	245,985
Reserve Margin	11,025	11,025
	4.69%	4.69%

NNG-PNG	EF	TOTAL
Design Day	211,182	######
Capacity	221,436	######
Reserve Margin	10,254	10,254
	4.86%	4.86%

NNG-NMU	EF	TOTAL
Design Day	23,778	23,778
Capacity	24,549	24,549
Reserve Margin	771	771
	3.24%	3.24%

MINNESOTA ENERGY RESOURCES - PNG-NNG

Financial Options

Heating Season 2011-2012

[TRADE SECRET DATA BEGINS

Units - Gas Daily Peaker Packages (Physical)

	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
1												

Premium - Gas Daily Peaker (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
1												

Units - Futures (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
1												
2												
3												
4												
5												
6												
7												
8												
Total		18,667		8,710		13,548		6,552		20,645	68,122	2,080,000
		560,000		270,000		420,000		190,000		640,000		2,080,000

Units - Call Options (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
1												
2												
3												
4												
5												
6												
Total		25,333		33,871		37,742		34,138		26,452	157,536	4,790,000
		760,000		1,050,000		1,170,000		990,000		820,000		4,790,000

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
1												
2												
3												
4												
5												
6												
Total	$ 0.2017	$ 153,257	$ 0.2220	$ 233,122	$ 0.2638	$ 308,606	$ 0.2950	$ 281,951	$ 0.3057	$ 250,678	$ 0.2563	$ 1,227,613
		$ 209,720		$ 317,490		$ 427,300		$ 395,870		$ 342,390		$ 1,692,770

Units - Collar Floor (put)

TRADE SECRET DATA ENDS]

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

11/12 Winter Portfolio Plan - MERC NNG-PNG Hedging Plan

[TRADE SECRET DATA BEGINS

10,000 Contract Size

REVISED: 9/13/2011

System	Purchase Month	Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
		Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
NNG -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Fixed Price														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														
Month/Daily														
Total													15,877,448	**100.00%**

NOTE:

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (PNG)

NOVEMBER, 2011 THROUGH MARCH, 2012

[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				-	-	-	-	-	-

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	Total Actual Seasonal Index			47,460	46,432	55,645	45,045	50,619	7,418,604

GAS DAILY PACKAGES

STORAGE Injection Month	Contract # Volume Injected	Contract # Volume Injected	Total Volume Injected
Total	4,196,785	359,520	4,556,305

TRADE SECRET DATA ENDS]

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

MINNESOTA ENERGY RESOURCES - PNG

As Proposed 08-	M-07-1405 Peoples Mn GS	M-08-1331 Peoples Mn GS	M-09- Peoples Mn GS	M-10- Peoples Mn GS	M-11- Peoples Mn GS	Proposed Change
Design Day	202,263	225,397	203,360	194,598	211,182	16,584
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	32.16%	30.56%	31.50%	35.92%	33.31%	-2.61%
Total Design Day Capacity (includes non-recallable capacity)	233,785	233,785	238,064	233,627	221,436	-12,191
Less: Windom	2,500	2,500	2,500	2,500	2,500	0
Less: Northwestern Energy	0	0	0	0	910	910
Less: LS Power	26,323	26,323	26,375	25,951	0	-25,951
Less: TF12B	7,000	7,000	7,000	0	0	0
Less: TF5						
Less: TFX(5)						
Total Design Day Capacity	197,962	197,962	202,189	205,176	218,026	12,850
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	100.00%	
Allocated Entitlements in PGA						
TF12B	43,858	29,906	35,221	34,875	42,396	7,521
TF12V	15,946	32,690	24,583	32,290	25,298	-6,992
TF5	29,619	26,827	29,619	28,785	29,011	226
TFX12	18,409	29,246	31,199	28,802	29,029	227
TFX(5)	90,130	79,293	81,567	80,424	81,057	633
TFX(5) (12-V)	0	0	0	0	0	0
TFX (October Only)	0	0	0	1,784	1,798	14
TFX (April Only)	0	0	0	1,784	1,798	14
NNG Zone Delivery Call Option	0	0	0	0	11,235	11,235
LS Power	26,323	26,323	26,375	25,951	0	-25,951
Bison *	0	0	0	44,589	44,940	351
NBPL *	0	0	0	44,589	44,940	351
Peak Capacity	224,285	224,285	228,564	231,127	218,026	-13,101
Total Allocated Entitlements in PGA	224,285	224,285	228,564	323,873	311,502	-12,371

* Bison/NBPL does not add incremental capacity but is utilized to deliver Rockies supply to NNG. Volume is not included in Peak Capacity.

	M-07-1405 Peoples Mn GS	M-08-1331 Peoples Mn GS	M-09- Peoples Mn GS	M-10- Peoples Mn GS	M-11- Peoples Mn GS	Proposed Change
Direct Assigned Entitlements in PGA						
Windom	2,500	2,500	2,500	2,500	2,500	0
Northwestern Energy	0	0	0	0	910	910
LS Power	26,323	26,323	0	0	0	0
TFX (October Only)	1,798	2,000	2,000	0	0	0
TFX (April Only)	1,798	2,000	2,000	0	0	0
TFX(5)	0	0	0	0	0	0
TFX(7)	0	0	0	0	0	0
TFX(5)	0	0	0	0	0	0
Total Direct Assignments	32,418	32,823	6,500	2,500	3,410	910
Total Capacity before Peak Shaving	256,703	257,108	235,064	233,627	221,436	-12,191
LP Peak Shaving	0	0	0	0		0
Total Design Day Capacity	253,108	253,108	231,064	233,627	221,436	-12,191
Total Transp. (with TFX Offpeak less LSP)	226,785	226,785	204,689	207,676	221,436	13,760
Total Annual Transportation	80,713	94,342	93,503	98,467	100,133	1,666
Total Seasonal Transportation	172,395	158,766	137,561	135,160	110,069	-25,091
Total Percent Seasonal	68.1%	62.7%	59.5%	57.9%	49.7%	-8.1%
LS Power as % of Total DD Capacity	10.4%	10.4%	11.4%	11.1%	0.0%	-11.1%
Reserve Margin	25.14%	12.29%	13.62%	20.06%	4.86%	-15.2%
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	0	0	0	0	0	0
Total Design Day Capacity w/ contract demand	233,785	233,785	238,064	233,627	221,436	-4,437
Factors	32.16%	30.56%	31.50%	35.92%	33.31%	4.42%
Other Entitlements not included in Peak Day Deliverability						
Field TF (TFF) (NMU direct assigned)	0	0	0	0	0	0
TFX Offpeak Old Oct. (60,000)	0	0	0	0	0	0
TFX Offpeak Old Oct. (35,000)	0	0	0	0	0	0
TFX Offpeak New Oct. (14,600)	0	0	0	0	0	0
TFX Offpeak New Apr. (39,600)	0	0	0	0	0	0
TFX Oct	1,798	2,000	2,000	1,784	1,798	14
TFX Apr	1,798	1,798	2,000	1,784	1,798	14
TFX Apr-Oct	0	0	0	0	0	0
TFX May-Sept	0	0	0	0	0	0
FDD Storage reservation	73,022	76,476	76,628	78,409	79,027	618
FDD Storage capacity	4,210,037	4,409,251	4,417,893	4,520,719	4,556,305	35,586
Nexen PSO	0	0	0	0	0	0
Tenaska PSO New	170,237	0	0	0	0	0
NGPL	0	0	0	0	0	0
SMS	20,537	20,537	20,577	20,226	20,385	159
SBA	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - PNG

Rate Impacts
NNG

1) General Service Residential: Avg. Annual Use:				86 Mcf					
Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	-26.24%	7.53%	5.79%	$0.2314
Demand Rate	$1.6893	$1.0883	$1.0362	$1.6103	$1.7414	3.08%	68.06%	8.14%	$0.1311
Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.1914	$6.4545	$6.7394	$7.3781	$7.7406	-15.78%	14.86%	4.91%	$0.3625
Avg. Annual Bill*	$790.46	$555.09	$579.59	$634.52	$665.69	-15.78%	14.86%	4.91%	$31.17
Effect of proposed commodity change on average annual bills:									$19.90
Effect of proposed demand change on average annual bills:									$11.27

2) Small Volume Interruptible: Avg. Annual Use:				4,371 Mcf					
Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	-26.24%	7.53%	5.79%	$0.2314
Demand Rate									$0.0000
Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.8956	$4.9833	$5.0967	$5.1613	$5.3927	-21.80%	5.81%	4.48%	$0.2314
Avg. Annual Bill*	$30,140.67	$21,782.00	$22,277.68	$22,560.04	$23,571.45	-21.80%	5.81%	4.48%	$1,011.41
Effect of proposed commodity change on average annual bills:									$1,011.41
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use:				11,202 Mcf					
Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	-26.24%	7.53%	5.79%	$0.2314
Demand Rate									$0.0000
Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.0523	$4.0991	$4.2534	$4.3180	$4.5494	-24.83%	6.96%	5.36%	$0.2314
Avg. Annual Bill*	$67,797.86	$45,918.12	$47,646.59	$48,370.24	$50,962.27	-24.83%	6.96%	5.36%	$2,592.04
Effect of proposed commodity change on average annual bills:									$2,592.04
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use:				4,800 Mcf					
Avg. Annual CD Volumes:				25 Mcf					
Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	-26.24%	7.53%	5.79%	$0.2314
Demand Rate	$19.6334	$10.3925	$9.3592	$10.7144	$10.8163	-44.91%	15.57%	0.95%	$0.1019
Comm. Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.8956	$4.9833	$5.0967	$5.1613	$5.3927	-21.80%	5.81%	4.48%	$0.2314
Total Demand Cost	$21.4334	$12.4649	$11.1592	$12.5144	$12.6163	-41.14%	13.06%	0.81%	$0.1019
Avg. Annual Bill*	$33,634.72	$24,231.46	$24,743.14	$25,087.10	$26,200.32	-22.10%	5.89%	4.44%	$1,113.22
Effect of proposed commodity change on average annual bills:									$1,110.67
Effect of proposed demand change on average annual bills:									$2.55

5) Large Volume Firm: Avg. Annual Use:				14,841 Mcf					
Avg. Annual CD Units:				75 Mcf					
Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.2246	-26.24%	7.53%	5.79%	$0.2314
Demand Rate	$19.6334	$10.3925	$9.3592	$10.7144	$10.8163	-44.91%	15.57%	0.95%	$0.1019
Comm. Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$0.1400	$1.6579	$1.4000	$1.4000	$1.4000	900.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.0523	$4.0991	$4.2534	$4.3180	$4.5494	-24.83%	6.96%	5.36%	$0.2314
Total Demand Cost	$19.7734	$12.0504	$10.7592	$12.1144	$12.2163	-38.22%	13.54%	0.84%	$0.1019
Avg. Annual Bill*	$91,305.19	$61,738.52	$63,931.65	$64,992.02	$68,433.73	-25.05%	7.04%	5.30%	$3,441.71
Effect of proposed commodity change on average annual bills:									$3,434.07
Effect of proposed demand change on average annual bills:									$7.64

* Average Annual Bill amount does not include customer charges.
** Commodity includes Upstream costs.

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.2314	5.79%	23.14%	$0.1311	8.14%	0.3625		4.91%
Sm Vol Inter. Service	$0.2314	5.79%	23.14%	$0.0000	0.00%	0.2314		4.48%
Lrg Vol Inter. Service	$0.2314	5.79%	23.14%	$0.0000	0.00%	0.2314		5.36%
Sm Vol Joint Service	$0.2314	5.79%	23.14%	$0.1019	0.95%	0.2314	***	4.48%
Lrg Vol Joint Service	$0.2314	5.79%	23.14%	$0.1019	0.95%	0.2314	***	5.36%

*** Joint total change includes only commodity change since not all joint customers purchase CD units.

MINNESOTA ENERGY RESOURCES - PNG

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

1) General Service Residential: Avg. Annual Use: 86 Mcf

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	-23.42%	11.65%	9.84%	$0.3929
Demand Rate	$1.6893	$1.0883	$1.0362	$1.6103	$1.5572	-7.82%	50.28%	-3.30%	($0.0531)
Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.1914	$6.4545	$6.7394	$7.3781	$7.7179	-16.03%	14.52%	4.61%	$0.3398
Avg. Annual Bill*	$790.46	$555.09	$579.59	$634.52	$663.74	-16.03%	14.52%	4.61%	$29.22
Effect of proposed commodity change on average annual bills:									$33.79
Effect of proposed demand change on average annual bills:									($4.56)

2) Small Volume Interruptible: Avg. Annual Use: 4,371 Mcf

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	-23.42%	11.65%	9.84%	$0.3929
Demand Rate									
Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.8956	$4.9833	$5.0967	$5.1613	$5.5542	-19.45%	8.98%	7.61%	$0.3929
Avg. Annual Bill*	$30,140.67	$21,782.00	$22,277.68	$22,560.04	$24,277.42	-19.45%	8.98%	7.61%	$1,717.38
Effect of proposed commodity change on average annual bills:									$1,717.38
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 11,202 Mcf

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	-23.42%	11.65%	9.84%	$0.3929
Demand Rate									
Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.0523	$4.0991	$4.2534	$4.3180	$4.7109	-22.16%	10.76%	9.10%	$0.3929
Avg. Annual Bill*	$67,797.86	$45,918.12	$47,646.59	$48,370.24	$52,771.53	-22.16%	10.76%	9.10%	$4,401.29
Effect of proposed commodity change on average annual bills:									$4,401.29
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 4,800 Mcf
Avg. Annual CD Volumes: 25 Mcf

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	-23.42%	11.65%	9.84%	$0.3929
Demand Rate	$19.6334	$10.3925	$9.3592	$10.7144	$16.9273	-13.78%	80.86%	57.99%	$6.2129
Comm. Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.8956	$4.9833	$5.0967	$5.1613	$5.5542	-19.45%	8.98%	7.61%	$0.3929
Total Demand Cost	$21.4334	$12.4649	$11.1592	$12.5144	$18.7273	-12.63%	67.82%	49.65%	$6.2129
Avg. Annual Bill*	$33,634.72	$24,231.46	$24,743.14	$25,087.10	$27,128.35	-19.34%	9.64%	8.14%	$2,041.25
Effect of proposed commodity change on average annual bills:									$1,885.93
Effect of proposed demand change on average annual bills:									$155.32

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

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov1/11 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	$5.7275	$3.7399	$3.9286	$3.9932	$4.3861	-23.42%	11.65%	9.84%	$0.3929
Demand Rate	$19.6334	$10.3925	$9.3592	$10.7144	$16.9273	-13.78%	80.86%	57.99%	$6.2129
Comm. Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$0.1400	$1.6579	$1.4000	$1.4000	$1.4000	900.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.0523	$4.0991	$4.2534	$4.3180	$4.7109	-22.16%	10.76%	9.10%	$0.3929
Total Demand Cost	$19.7734	$12.0504	$10.7592	$12.1144	$18.3273	-7.31%	70.34%	51.29%	$6.2129
Avg. Annual Bill*	$91,305.19	$61,738.52	$63,931.65	$64,992.02	$71,289.05	-21.92%	11.51%	9.69%	$6,297.03
Effect of proposed commodity change on average annual bills:									$5,831.06
Effect of proposed demand change on average annual bills:									$465.97

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

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.3929	9.84%	39.29%	($0.0531)	-3.30%	0.3398		4.61%
Sm Vol Inter. Service	$0.3929	9.84%	39.29%	$0.0000	0.00%	0.3929		7.61%
Lrg Vol Inter. Service	$0.3929	9.84%	39.29%	$0.0000	0.00%	0.3929		9.10%
Sm Vol Joint Service	$0.3929	9.84%	39.29%	$6.2129	57.99%	0.3929	***	7.61%
Lrg Vol Joint Service	$0.3929	9.84%	39.29%	$6.2129	57.99%	0.3929	***	9.10%

*** Joint total change includes only commodity change since not all joint customers purchase CD units.

MINNESOTA ENERGY RESOURCES - PNG

Change in Costs due to November 1, 2011 Change in Entitlement Levels and Related Demand Costs

NNG

	Contract	Oct-11 PGA	Nov-11 Entitlement	Entitlement Change	Months	Oct-11 Rate/MCF	Oct-11 Total Cost	Entitlement Total Cost	Entitlement Change
TF-12-B (Max Rate)	112495	29,675	37,959	8,284	12	$ 7.5776	$2,698,383	$3,451,657	$753,274
TF-12-B (Discount)	112495	5,200	4,437	(763)	12	$ 6.4818	$404,464	$345,117	($59,347)
TF-12-V (Max Rate)	112495	32,290	25,298	(6,992)	12	$ 9.0926	$3,523,201	$2,760,295	($762,906)
TF-5 (Max Rate)	112495	28,785	28,248	(537)	5	$ 15.1530	$2,180,896	$2,140,210	($40,686)
TF-5 (Discount)	112495	0	763	763	5	$ 7.6000	$0	$28,994	$28,994
TFX-12 (Max Rate)	112486	9,651	9,727	76	12	$ 9.6288	$1,115,131	$1,123,912	$8,781
TFX-12 (Discount)	111866	1,144	1,153	9	12	$ 4.8640	$66,773	$67,298	$525
TFX-12 (Discount)	111866	7,376	7,434	58	12	$ 5.4720	$484,338	$488,146	$3,809
TFX-12 (Discount)	111866	10,631	10,715	84	12	$ 2.2192	$283,108	$285,345	$2,237
TFX-5 (Max Rate)	112486	51,163	51,383	220	5	$ 15.1530	$3,876,365	$3,893,033	$16,668
TFX-5 (Discount)	112486	1,605	1,800	195	5	$ 7.6000	$61,030	$68,400	$7,370
TFX-5 (Discount)	111866	338	341	3	5	$ 4.8640	$8,220	$8,293	$73
TFX-5 (Discount)	111866	2,180	2,198	18	5	$ 5.4720	$59,645	$60,137	$492
TFX-5 (Discount)	111866	19,788	19,943	155	5	$ 15.1392	$1,497,872	$1,509,605	$11,733
TFX-5 (Discount)	112561	5,351	5,393	42	5	$ 4.5600	$122,003	$122,960	$958
TFX-7 (Discount)	111866	0	0	0	7	$ 2.2192	$0	$0	$0
TFX Oct (Max Rate)	112486	1,784	1,798	14	1	$ 5.6830	$10,138	$10,218	$80
TFX Apr (Max Rate)	112486	1,784	1,798	14	1	$ 5.6830	$10,138	$10,218	$80
SMS Charge		20,226	20,385	159	12	$ 2.1800	$529,112	$533,272	$4,159
LS Power		25,951	0	(25,951)	3	$ 4.3463	$338,369	$0	($338,369)
WINDOM		2,500	2,500	0	12	$ -	$0	$0	$0
Northwestern Energy		0	910	910	12	$ 8.0000	$0	$87,360	$87,360
NNG Zone GDD Call Option		0	11,235	11,235	3	$ 0.9100	$0	$30,672	$30,672
Bison		44,589	44,940	351	12	$ 17.4800	$8,183,865	$9,426,614	$1,242,749
NBPL		44,589	44,940	351	12	$ 6.9920	$3,273,546	$3,770,646	$497,100
FDD: Storage Reservation		73,460	74,039	579	12	$ 1.7140	$1,510,925	$1,522,834	$11,909
FDD: Storage Reservation		4,949	4,988	39	12	$ 3.3157	$196,913	$198,465	$1,552
FDD: Storage Cycle Volume		847,070	853,738	6,668	5	$ 0.3567	$1,510,749	$1,522,642	$11,892
FDD: Storage Cycle Volume		57,074	57,523	449	5	$ 0.6901	$196,934	$198,483	$1,549
Total Demand Cost							$32,142,118	##########	$1,522,709

Costs Assigned In Commodity:	Oct-11 PGA	Nov-11 Entitlement	Entitlement Change	Months	Oct-11 Rate/MCF	Oct-11 Total Cost	Entitlement Total Cost	Entitlement Change
Upstream								
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	4,520,719	4,556,305	35,586	1	$0.0000	$0	$0	$0
FDD Injection	4,520,719	4,556,305	35,586	1	$0.0000	$0	$0	$0
							$0	$0
							$0	$0
Producer Demand Payments/Option Premium						$2,672,469	$1,227,613	($1,444,856)
Total Commodity Costs						$2,672,469	$1,227,613	($1,444,856)

MINNESOTA ENERGY RESOURCES - PNG

Daily Total Throughput Data - July 1, 2010 through June 30, 2011

NNG

Base	26,150
Variable	2,217

Date	4.34% Cloquet Adjusted HDD	32.74% Minneapolis Adjusted HDD	48.84% Rochester Adjusted HDD	14.08% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/10	0	0	0	0	0	36,418	26,150
7/2/10	0	0	0	0	0	30,701	26,150
7/3/10	0	0	0	0	0	27,703	26,150
7/4/10	0	0	0	0	0	25,851	26,150
7/5/10	0	0	0	0	0	31,033	26,150
7/6/10	0	0	0	0	0	40,047	26,150
7/7/10	0	0	0	0	0	41,786	26,150
7/8/10	0	0	0	0	0	33,604	26,150
7/9/10	0	0	0	0	0	31,930	26,150
7/10/10	0	0	0	0	0	30,372	26,150
7/11/10	4	0	0	0	0	31,202	26,558
7/12/10	1	0	0	0	0	36,428	26,249
7/13/10	0	0	0	0	0	35,563	26,150
7/14/10	0	0	0	0	0	38,406	26,150
7/15/10	0	0	0	0	0	41,437	26,150
7/16/10	0	0	0	0	0	40,757	26,150
7/17/10	0	0	0	0	0	31,741	26,150
7/18/10	0	0	0	0	0	30,681	26,150
7/19/10	0	0	0	0	0	36,327	26,150
7/20/10	0	0	0	0	0	36,755	26,150
7/21/10	0	0	0	0	0	40,904	26,150
7/22/10	0	0	0	0	0	39,716	26,150
7/23/10	0	0	0	0	0	45,131	26,150
7/24/10	0	0	0	0	0	28,285	26,150
7/25/10	0	0	0	0	0	29,376	26,150
7/26/10	0	0	0	0	0	42,599	26,150
7/27/10	0	0	0	0	0	48,129	26,150
7/28/10	0	0	0	0	0	41,497	26,150
7/29/10	0	0	0	0	0	39,053	26,150
7/30/10	0	0	0	0	0	31,902	26,150
7/31/10	0	0	0	0	0	27,400	26,150
8/1/10	0	0	0	0	0	29,336	26,150
8/2/10	0	0	0	0	0	43,523	26,150
8/3/10	0	0	0	0	0	46,240	26,150
8/4/10	0	0	0	0	0	46,784	26,150
8/5/10	1	0	0	0	0	40,583	26,255
8/6/10	0	0	0	0	0	30,409	26,150
8/7/10	0	0	0	0	0	25,922	26,150
8/8/10	0	0	0	0	0	34,737	26,150
8/9/10	0	0	0	0	0	47,254	26,150
8/10/10	0	0	0	0	0	49,177	26,150
8/11/10	0	0	0	0	0	51,250	26,150
8/12/10	0	0	0	0	0	49,612	26,150
8/13/10	0	0	0	0	0	38,334	26,150
8/14/10	0	0	0	0	0	26,602	26,150
8/15/10	6	0	0	1	0	30,932	27,040
8/16/10	9	0	0	0	0	34,509	27,004
8/17/10	0	0	0	0	0	35,405	26,150
8/18/10	6	0	0	0	0	33,973	26,745
8/19/10	2	0	0	0	0	36,858	26,356
8/20/10	3	0	0	0	0	39,540	26,453
8/21/10	0	0	0	0	0	28,747	26,150
8/22/10	0	0	0	0	0	32,696	26,150
8/23/10	0	0	0	0	0	34,867	26,150
8/24/10	3	0	1	2	1	34,232	28,348
8/25/10	7	0	6	3	4	35,779	34,827
8/26/10	1	0	0	0	0	36,024	26,250
8/27/10	0	0	0	0	0	31,246	26,150
8/28/10	0	0	0	0	0	27,107	26,150
8/29/10	0	0	0	0	0	29,373	26,150
8/30/10	0	0	0	0	0	35,367	26,150
8/31/10	0	0	0	0	0	36,279	26,150
9/1/10	1	0	0	0	0	40,634	26,251
9/2/10	8	1	2	7	3	35,217	32,305
9/3/10	15	11	15	13	13	31,620	55,445
9/4/10	16	6	9	7	8	29,019	43,982
9/5/10	9	1	0	1	1	26,759	28,192
9/6/10	11	2	3	1	3	31,043	33,025
9/7/10	16	11	12	13	12	37,524	53,580
9/8/10	18	5	5	4	6	36,677	38,776
9/9/10	14	7	10	5	8	37,649	44,650
9/10/10	8	2	2	10	4	35,147	33,975
9/11/10	9	2	4	4	4	29,285	34,664
9/12/10	7	0	0	1	0	30,924	27,110
9/13/10	12	1	4	3	3	37,720	33,596
9/14/10	14	3	2	0	3	36,312	32,141
9/15/10	18	8	2	2	5	36,241	36,846
9/16/10	15	12	11	13	12	37,351	51,682
9/17/10	15	11	9	13	10	34,787	48,861
9/18/10	20	11	16	20	15	34,670	59,091
9/19/10	13	8	9	9	9	34,420	45,165
9/20/10	9	0	0	0	0	36,907	26,981
9/21/10	16	5	3	6	5	37,863	37,029
9/22/10	12	6	1	6	4	36,871	34,282
9/23/10	17	1	4	6	4	34,442	34,304

MERC

9/24/10	22	13	15	13	14	36,128	58,068
9/25/10	21	14	16	16	16	37,410	60,616
9/26/10	13	10	15	9	12	38,106	53,525
9/27/10	7	0	2	3	2	39,378	30,310
9/28/10	15	6	8	2	7	39,876	41,041
9/29/10	9	2	1	7	3	38,166	31,860
9/30/10	12	4	8	7	7	38,541	40,931
10/1/10	20	11	8	11	10	39,105	47,820
10/2/10	25	19	24	22	22	45,003	74,716
10/3/10	19	16	20	18	18	46,202	66,655
10/4/10	16	11	16	12	14	50,004	56,432
10/5/10	6	3	7	1	5	59,421	36,637
10/6/10	10	6	8	12	8	60,683	43,877
10/7/10	2	3	3	3	3	58,250	33,134
10/8/10	0	0	0	0	0	52,152	26,150
10/9/10	15	0	0	0	1	47,760	27,591
10/10/10	5	0	0	3	1	49,003	27,629
10/11/10	14	0	0	1	1	58,855	27,779
10/12/10	15	6	4	15	7	61,095	41,628
10/13/10	13	11	13	16	13	65,004	54,177
10/14/10	18	10	12	17	12	65,382	53,416
10/15/10	17	12	14	10	13	60,413	54,371
10/16/10	19	12	13	19	14	57,232	56,625
10/17/10	25	17	15	20	17	61,757	63,207
10/18/10	21	18	21	20	20	73,943	70,140
10/19/10	15	13	15	18	15	54,885	58,904
10/20/10	21	13	14	17	14	55,856	57,478
10/21/10	28	21	26	18	23	62,852	77,933
10/22/10	16	7	9	3	8	43,854	43,887
10/23/10	22	7	6	9	7	35,263	41,670
10/24/10	20	8	6	16	9	39,173	46,179
10/25/10	14	10	12	20	13	45,869	54,173
10/26/10	23	30	29	36	30	74,695	92,914
10/27/10	34	31	36	42	35	89,098	104,111
10/28/10	38	33	38	33	36	97,770	105,149
10/29/10	33	24	26	18	25	71,272	80,791
10/30/10	32	25	26	28	26	67,030	83,952
10/31/10	31	25	30	28	28	77,642	88,487
11/1/10	27	22	26	24	25	81,696	80,513
11/2/10	22	20	24	21	22	73,877	74,915
11/3/10	24	20	23	21	22	69,848	74,361
11/4/10	38	32	36	36	35	88,404	102,948
11/5/10	33	30	34	32	32	85,087	97,490
11/6/10	27	20	26	20	23	68,341	77,460
11/7/10	24	16	15	11	15	53,613	60,335
11/8/10	20	13	14	10	14	55,140	56,210
11/9/10	19	10	10	11	11	48,346	49,842
11/10/10	19	11	17	27	17	57,456	63,293
11/11/10	26	21	24	26	23	73,057	78,093
11/12/10	26	29	34	34	32	86,268	96,722
11/13/10	36	36	35	37	35	89,523	104,387
11/14/10	36	35	34	37	35	92,844	103,762
11/15/10	40	33	28	29	30	89,715	93,360
11/16/10	40	34	30	34	32	94,690	98,097
11/17/10	41	35	35	40	36	101,222	105,792
11/18/10	41	37	38	42	39	111,212	111,876
11/19/10	47	40	40	45	41	106,648	116,726
11/20/10	50	46	44	49	45	107,513	126,880
11/21/10	46	36	32	45	35	97,160	104,741
11/22/10	54	47	50	58	50	134,487	137,649
11/23/10	51	50	51	54	51	136,257	139,821
11/24/10	51	46	51	50	49	123,592	135,386
11/25/10	60	62	59	59	60	141,593	159,642
11/26/10	54	50	51	44	50	130,336	136,898
11/27/10	49	47	46	40	46	109,160	127,349
11/28/10	37	32	30	30	31	89,395	94,411
11/29/10	34	32	38	45	37	105,115	107,673
11/30/10	47	48	55	62	53	146,065	144,727
12/1/10	61	52	55	55	54	146,893	146,082
12/2/10	64	51	50	51	51	144,007	139,641
12/3/10	58	52	54	55	54	141,631	144,927
12/4/10	56	54	60	64	58	135,914	155,525
12/5/10	52	56	64	62	60	148,862	160,016
12/6/10	62	55	60	64	59	149,333	156,468
12/7/10	60	58	66	60	62	157,611	164,595
12/8/10	56	54	59	57	57	152,795	152,545
12/9/10	50	44	46	43	45	129,092	125,740
12/10/10	62	48	40	50	45	120,790	126,480
12/11/10	78	65	66	83	69	150,807	178,531
12/12/10	78	73	81	80	78	179,433	199,538
12/13/10	77	66	75	66	71	190,722	182,935
12/14/10	59	65	66	58	64	173,258	168,843
12/15/10	57	55	56	52	55	154,266	147,545
12/16/10	59	53	59	61	57	152,858	152,590
12/17/10	57	59	66	61	62	157,902	164,361
12/18/10	57	59	65	65	63	153,763	165,700
12/19/10	61	54	59	58	57	147,842	152,976
12/20/10	52	45	46	52	46	134,421	129,171
12/21/10	42	44	48	60	48	130,171	133,186
12/22/10	44	38	39	48	40	117,778	115,149
12/23/10	48	43	42	46	43	117,943	122,108
12/24/10	54	47	47	56	49	116,919	134,128
12/25/10	58	55	55	66	57	131,498	151,840
12/26/10	56	53	54	67	55	138,082	148,427
12/27/10	47	51	57	56	54	143,192	146,340
12/28/10	40	40	51	46	46	122,203	128,765

MERC

12/29/10	40	36	39	39	38	105,791	110,753
12/30/10	59	42	47	54	47	114,860	129,975
12/31/10	65	60	61	72	62	151,974	164,439
1/1/11	70	68	73	74	72	171,783	184,933
1/2/11	71	58	58	58	58	144,098	155,798
1/3/11	66	60	59	59	60	151,215	158,675
1/4/11	64	63	65	60	63	167,302	166,916
1/5/11	62	51	53	46	52	143,701	141,619
1/6/11	66	54	57	44	54	145,219	146,853
1/7/11	72	64	66	68	66	165,098	172,100
1/8/11	67	63	68	64	66	167,898	172,324
1/9/11	60	61	63	60	62	154,053	162,557
1/10/11	52	49	50	56	50	142,217	137,949
1/11/11	48	52	53	68	54	141,085	146,699
1/12/11	52	57	65	70	63	162,419	165,098
1/13/11	53	58	58	63	59	157,299	156,268
1/14/11	59	57	56	60	57	145,213	152,662
1/15/11	70	60	64	70	64	156,441	167,784
1/16/11	66	58	59	62	59	151,627	157,813
1/17/11	61	52	52	63	54	142,710	146,004
1/18/11	66	62	64	80	66	161,556	171,420
1/19/11	65	64	67	75	67	172,125	174,614
1/20/11	86	75	81	77	79	197,587	200,702
1/21/11	83	73	78	71	76	184,362	193,960
1/22/11	82	70	75	81	74	181,956	191,165
1/23/11	75	67	71	76	70	167,272	182,135
1/24/11	54	47	49	54	49	144,346	135,346
1/25/11	51	51	52	54	52	143,173	141,335
1/26/11	46	45	51	49	49	135,490	133,956
1/27/11	45	42	42	44	42	119,470	119,986
1/28/11	48	41	45	44	43	113,888	122,485
1/29/11	54	49	48	65	51	127,774	139,325
1/30/11	59	50	50	63	52	132,506	141,084
1/31/11	68	58	58	61	59	150,210	156,549
2/1/11	73	68	68	85	70	173,242	182,321
2/2/11	70	65	76	78	73	182,516	187,312
2/3/11	53	55	65	65	61	155,390	161,885
2/4/11	45	43	47	46	46	123,288	127,164
2/5/11	40	44	46	41	44	113,960	124,081
2/6/11	57	50	47	64	51	124,245	138,847
2/7/11	76	71	71	87	73	177,195	188,632
2/8/11	68	74	82	84	79	193,191	200,699
2/9/11	77	72	77	77	75	189,837	193,061
2/10/11	68	66	68	60	66	175,935	172,906
2/11/11	57	51	47	43	48	133,178	133,672
2/12/11	46	36	40	39	39	104,685	112,053
2/13/11	31	28	35	36	33	89,039	98,769
2/14/11	34	33	36	39	35	99,694	104,619
2/15/11	34	32	37	34	35	97,451	103,470
2/16/11	24	26	32	28	29	83,096	90,752
2/17/11	42	36	37	41	37	100,489	109,109
2/18/11	62	52	50	48	51	126,952	138,871
2/19/11	58	48	44	45	46	111,696	128,274
2/20/11	55	46	45	45	46	123,457	127,614
2/21/11	57	54	49	54	51	139,549	140,189
2/22/11	49	50	49	49	49	123,828	135,499
2/23/11	48	41	43	52	44	114,788	123,417
2/24/11	64	54	52	73	56	139,282	151,043
2/25/11	72	64	64	72	66	160,017	171,941
2/26/11	70	61	57	60	59	155,158	157,052
2/27/11	56	53	56	58	55	136,447	148,743
2/28/11	52	47	55	59	53	131,498	143,222
3/1/11	62	52	55	61	55	140,425	147,997
3/2/11	63	59	57	58	58	155,159	155,017
3/3/11	48	41	36	41	39	109,673	112,149
3/4/11	51	46	43	65	47	119,151	130,879
3/5/11	48	46	49	59	49	123,183	135,335
3/6/11	48	45	44	48	45	110,147	125,176
3/7/11	49	40	35	54	40	113,792	114,398
3/8/11	41	33	36	45	37	100,710	107,318
3/9/11	40	37	39	49	40	108,005	114,688
3/10/11	38	42	45	47	44	112,524	123,013
3/11/11	34	41	44	45	43	102,824	120,827
3/12/11	50	51	56	54	54	125,849	145,552
3/13/11	44	44	46	50	46	121,416	127,617
3/14/11	40	40	40	38	40	103,764	114,480
3/15/11	36	31	34	29	32	91,966	97,823
3/16/11	29	26	29	22	27	70,457	86,036
3/17/11	31	26	28	29	28	76,251	87,240
3/18/11	39	35	36	33	36	91,698	105,177
3/19/11	31	31	30	30	30	70,355	93,462
3/20/11	31	27	28	26	27	79,613	87,115
3/21/11	32	27	27	35	28	87,508	88,933
3/22/11	49	38	38	38	39	112,007	111,588
3/23/11	55	48	48	49	49	124,709	134,122
3/24/11	45	40	42	46	42	111,400	119,014
3/25/11	53	44	41	41	43	107,324	121,126
3/26/11	53	43	44	44	44	108,042	123,765
3/27/11	47	40	41	41	41	105,320	117,079
3/28/11	42	37	36	36	37	102,628	107,443
3/29/11	36	35	33	35	34	96,173	100,818
3/30/11	34	28	27	30	28	84,275	88,053
3/31/11	29	26	26	27	26	81,630	84,059
4/1/11	32	29	30	30	30	81,577	91,919
4/2/11	25	21	23	24	22	58,020	75,689
4/3/11	33	22	16	23	20	62,698	69,716

MERC

4/4/11	36	30	33	33	32	90,069	97,145
4/5/11	29	21	20	20	21	62,681	72,232
4/6/11	29	19	21	21	21	58,142	72,274
4/7/11	20	13	16	19	16	54,753	61,105
4/8/11	17	11	13	14	13	43,870	54,459
4/9/11	18	11	8	13	10	39,339	48,364
4/10/11	24	6	4	24	8	43,275	44,144
4/11/11	22	13	19	19	17	50,892	64,142
4/12/11	11	7	9	7	8	41,779	43,465
4/13/11	27	19	18	27	20	57,263	70,261
4/14/11	41	26	32	32	30	84,284	93,376
4/15/11	38	28	33	34	32	88,746	96,320
4/16/11	38	34	37	35	36	88,777	104,890
4/17/11	36	25	25	31	26	69,026	84,557
4/18/11	35	24	24	29	25	68,476	81,225
4/19/11	32	28	36	35	33	94,076	100,128
4/20/11	30	28	31	32	30	87,859	92,088
4/21/11	24	23	25	30	25	74,709	81,510
4/22/11	28	24	25	25	25	73,269	80,860
4/23/11	25	23	23	28	24	64,613	78,666
4/24/11	17	16	19	20	18	49,151	65,304
4/25/11	12	11	11	18	12	47,726	53,327
4/26/11	29	28	27	27	27	77,060	86,730
4/27/11	33	29	30	21	28	81,219	89,202
4/28/11	24	19	28	15	23	74,163	76,766
4/29/11	12	10	14	16	13	46,555	55,137
4/30/11	29	21	21	29	23	58,291	76,283
5/1/11	39	32	28	29	30	81,179	92,344
5/2/11	31	31	34	32	33	89,277	98,430
5/3/11	23	18	24	19	21	60,613	73,329
5/4/11	14	10	12	13	12	47,604	51,699
5/5/11	24	12	15	13	14	47,352	57,176
5/6/11	14	3	4	7	5	35,572	36,606
5/7/11	19	3	6	4	6	31,512	38,688
5/8/11	14	6	4	4	5	35,565	36,556
5/9/11	18	3	6	1	5	42,392	37,133
5/10/11	18	0	0	0	1	39,950	27,859
5/11/11	3	0	0	1	0	40,052	26,812
5/12/11	15	12	1	22	8	38,171	44,380
5/13/11	20	17	19	25	19	43,889	68,369
5/14/11	20	19	22	26	21	55,365	73,476
5/15/11	25	15	16	18	16	45,575	62,329
5/16/11	15	9	14	15	13	44,391	54,097
5/17/11	15	6	10	12	9	42,483	46,370
5/18/11	12	0	5	8	4	35,620	35,609
5/19/11	7	0	2	0	1	34,562	29,274
5/20/11	7	0	0	3	1	29,914	27,866
5/21/11	17	0	0	1	1	27,831	28,150
5/22/11	9	0	0	5	1	31,134	28,422
5/23/11	9	0	0	4	1	33,655	28,370
5/24/11	19	7	6	8	7	35,612	41,670
5/25/11	17	11	16	19	15	43,882	59,168
5/26/11	24	10	13	10	12	40,318	52,688
5/27/11	19	10	10	12	11	36,556	49,724
5/28/11	8	3	0	2	2	27,784	29,857
5/29/11	10	1	0	2	1	27,485	28,584
5/30/11	16	0	0	0	1	30,245	27,723
5/31/11	4	1	0	8	2	36,655	29,994
6/1/11	10	0	0	0	0	36,702	27,111
6/2/11	14	0	0	0	1	36,913	27,526
6/3/11	0	0	0	0	0	32,422	26,150
6/4/11	5	0	0	0	0	32,307	26,670
6/5/11	4	0	0	0	0	31,566	26,550
6/6/11	0	0	0	0	0	38,575	26,150
6/7/11	7	0	0	0	0	42,369	26,779
6/8/11	11	0	0	5	1	37,546	28,664
6/9/11	17	6	7	9	7	34,190	41,969
6/10/11	16	9	11	11	10	32,950	49,122
6/11/11	12	4	9	5	7	28,714	41,462
6/12/11	7	4	9	6	7	31,544	41,185
6/13/11	4	0	1	0	1	34,910	27,788
6/14/11	1	0	0	6	1	33,874	27,984
6/15/11	14	0	1	1	1	32,994	28,970
6/16/11	9	0	0	0	0	32,613	27,051
6/17/11	4	0	0	0	0	28,806	26,570
6/18/11	14	0	0	1	1	25,812	27,844
6/19/11	16	0	0	0	1	27,985	27,709
6/20/11	9	0	0	0	0	32,117	27,004
6/21/11	12	0	0	0	1	32,959	27,276
6/22/11	15	3	4	7	5	34,882	37,132
6/23/11	10	8	9	8	8	35,763	44,879
6/24/11	0	0	0	0	0	29,370	26,150
6/25/11	0	0	3	0	2	27,301	29,593
6/26/11	2	0	0	0	0	30,540	26,352
6/27/11	6	0	0	1	0	35,986	27,032
6/28/11	4	0	0	0	0	35,417	26,550
6/29/11	2	0	0	0	0	33,504	26,356
6/30/11	2	0	0	0	0	32,108	26,354
Totals	10,248	8,468	8,934	9,488	8,917	########	29,312,910

* Volumes include interruptible and transportation volumes except for transportation volumes that are not located behind MERC citygates.

MERC

** Design Model numbers are used to calculate firm volumes only

MINNESOTA ENERGY RESOURCES - PNG

Customer Counts by PGAC Class - July 1, 2010 through June 30, 2011

Rate Class	Tariff Rate Designation	Jul-10 Average Customers	Aug-10 Average Customers	Sep-10 Average Customers	Oct-10 Average Customers	Nov-10 Average Customers	Dec-10 Average Customers	Jan-11 Average Customers	Feb-11 Average Customers	Mar-11 Average Customers	Apr-11 Average Customers	May-11 Average Customers	Jun-11 Average Customers
Residential w/ Heat	MN001/007/008	142,297	142,250	142,166	141,649	142,850	143,636						
Residential w/o Heat	MN002/009/010	935	918	936	943	950	941						
Commercial-SV	MN050/053/054/070/076/078	6,392	6,360	6,359	5,896	6,393	6,467						
Commercial-LV	MN056/060/063/064/065/071/077	7,328	7,313	7,343	7,702	7,371	7,424						
SV-Joint	MN104	2	1	2	0	2	2						
SV-Interruptible	MN125/128/135	339	331	342	341	346	337						
LV-Interruptible	MN200/201/207	47	37	50	39	54	52						
LV-Interruptible-ML	MN220/221	0	0	0	0	0	0						
Transport	MN590	0	0	0	0	1	0						
Transport	MN509/514/589	5	5	7	3	7	11						
Transport	MN518	0	0	1	0	1	1						
Transport	MN502/507/82L	2	0	3	0	3	3						
Transport	MN500/574/81L	1	0	2	0	2	1						
Transport	MN501/506/522/523/80L	24	18	20	14	20	21						
Transport	MN/504/505/539	13	13	8	13	8	8						
Transport	MN/512	0	0	0	0	0	0						
Transport	MN/515	0	0	0	0	0	1						
Transport	MN/517	0	0	0	0	0	0						
Transport	MN/519	0	0	0	0	0	0						
Transport	MN/535	0	0	1	0	1	1						
Total		157,385	157,246	157,240	156,600	158,009	158,906	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - PNG

Projected Fixed Cost - November 2011 through March 2012

Futures Contracts WACOG

NNG-PNG
Futures

Nov-11 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/31/11	120,506	$ 4.8940	$ 589,758	$ 3.6310	$ 437,558	$ 152,199
06/16/11	113,418	$ 4.6510	$ 527,506	$ 3.6310	$ 411,820	$ 115,686
07/25/11	99,241	$ 4.4700	$ 443,605	$ 3.6310	$ 360,342	$ 83,263
08/02/11	85,063	$ 4.2550	$ 361,944	$ 3.6310	$ 308,865	$ 53,079
09/21/11	70,886	$ 3.8260	$ 271,210	$ 3.6310	$ 257,387	$ 13,823
10/03/11	70,886	$ 3.6160	$ 256,324	$ 3.6310	$ 257,387	$ (1,063)
Total	560,000		$ 2,450,347		$ 2,033,360	$ 416,987
WACOG			$ 4.3756		$ 3.6310	$ 0.7446

Dec-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/31/11	66,000	$ 5.0870	$ 335,742	$ 4.0440	$ 266,904	$ 68,838
06/16/11	48,000	$ 4.8410	$ 232,368	$ 4.0440	$ 194,112	$ 38,256
06/16/11	18,000	$ 4.8420	$ 87,156	$ 4.0440	$ 72,792	$ 14,364
07/07/11	48,000	$ 4.5500	$ 218,400	$ 4.0440	$ 194,112	$ 24,288
08/04/11	30,000	$ 4.2840	$ 128,520	$ 4.0440	$ 121,320	$ 7,200
09/19/11	30,000	$ 4.1800	$ 125,400	$ 4.0440	$ 121,320	$ 4,080
10/05/11	30,000	$ 3.9080	$ 117,240	$ 4.0440	$ 121,320	$ (4,080)
Total	270,000		$ 1,244,826		$ 1,091,880	$ 152,946
WACOG			$ 4.6105		$ 4.0440	$ 0.5665

Jan-12 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/26/11	85,217	$ 4.9410	$ 421,059	$ 4.1910	$ 357,146	$ 63,913
06/22/11	85,217	$ 4.8580	$ 413,986	$ 4.1910	$ 357,146	$ 56,840
07/21/11	79,130	$ 4.7690	$ 377,373	$ 4.1910	$ 331,636	$ 45,737
08/16/11	36,522	$ 4.4320	$ 161,864	$ 4.1910	$ 153,063	$ 8,802
08/16/11	30,435	$ 4.4330	$ 134,917	$ 4.1910	$ 127,552	$ 7,365
09/15/11	54,783	$ 4.3300	$ 237,209	$ 4.1910	$ 229,594	$ 7,615
10/20/11	48,696	$ 3.9670	$ 193,176	$ 4.1910	$ 204,083	$ (10,908)
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
Total	420,000		$ 1,939,584		$ 1,760,220	$ 179,364
WACOG			$ 4.6181		$ 4.1910	$ 0.4271

Feb-12 (29)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/26/11	52,778	$ 4.9000	$ 258,611	$ 4.2190	$ 222,669	$ 35,942
06/30/11	42,222	$ 4.8300	$ 203,933	$ 4.2190	$ 178,136	$ 25,798
07/07/11	15,833	$ 4.6580	$ 73,752	$ 4.2190	$ 66,801	$ 6,951
07/07/11	21,111	$ 4.6620	$ 98,420	$ 4.2190	$ 89,068	$ 9,352
08/25/11	21,111	$ 4.3340	$ 91,496	$ 4.2190	$ 89,068	$ 2,428
09/16/11	21,111	$ 4.3140	$ 91,073	$ 4.2190	$ 89,068	$ 2,006
10/06/11	15,833	$ 4.1000	$ 64,917	$ 4.2190	$ 66,801	$ (1,884)
Total	190,000		$ 882,202		$ 801,610	$ 80,592
WACOG			$ 4.6432		$ 4.2190	$ 0.4242

Mar-12 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/19/11	126,593	$ 4.7660	$ 603,344	$ 4.1105	$ 520,362	$ 82,982
06/23/11	42,198	$ 4.6590	$ 196,600	$ 4.1105	$ 173,454	$ 23,145
06/23/11	84,396	$ 4.6600	$ 393,284	$ 4.1105	$ 346,908	$ 46,375
07/27/11	126,593	$ 4.6700	$ 591,191	$ 4.1105	$ 520,362	$ 70,829
08/29/11	98,462	$ 4.2840	$ 421,809	$ 4.1105	$ 404,726	$ 17,083
09/22/11	84,396	$ 4.1800	$ 352,774	$ 4.1105	$ 346,908	$ 5,865
10/21/11	77,363	$ 3.9250	$ 303,648	$ 4.1105	$ 317,999	$ (14,351)
Total	640,000		$ 2,862,650		$ 2,630,720	$ 231,930
WACOG			$ 4.4729		$ 4.1105	$ 0.3624

Total

	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	451,095	$ 4.8959	$ 2,208,514	$ 4.0006	$ 1,804,640	$ 403,874
	331,055	$ 4.7557	$ 1,574,393	$ 3.9711	$ 1,314,667	$ 259,725
	296,600	$ 4.6364	$ 1,375,169	$ 3.9733	$ 1,178,479	$ 196,690
	317,290	$ 4.5127	$ 1,431,820	$ 3.9884	$ 1,265,469	$ 166,350
	250,894	$ 4.1769	$ 1,047,952	$ 3.9860	$ 1,000,053	$ 47,899
	261,175	$ 4.0692	$ 1,062,780	$ 3.9984	$ 1,044,277	$ 18,503
	171,892	$ 3.9501	$ 678,981	$ 4.1317	$ 710,203	$ (31,223)
	2,080,000		$ 9,379,609		$ 8,317,790	$ 1,061,819
			$ 4.5094		$ 3.9989	$ 0.5105

MINNESOTA ENERGY RESOURCES - PNG

Projected Storage Cost - November 2011 through March 2012

Month/ Year	K#118657 NNG Storage	Storage K#122800 LS Power	Total NNG Storage	WACOG Projected K#118657 NNG WACOG	Projected K#122800 NNG WACOG	K#118657 NNG Storage Cost	K#122800 NNG Storage Cost	Total NNG Storage Cost	GLGT/VGT Centra AECO Storage	GLGT/VGT Centra AECO Storage WACOG	GLGT/VGT Centra AECO Storage Cost
Nov-11	455,259	39,000	494,259	$ 4.1398	$ 4.1398	$ 1,884,666	$ 161,451	$ 2,046,116	85,304	$ 3.8600	$ 329,277
Dec-11	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	229,242	$ 3.8600	$ 884,885
Jan-12	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	229,242	$ 3.8600	$ 884,885
Feb-12	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	214,452	$ 3.8600	$ 827,795
Mar-12	455,259	39,000	494,259	$ 4.1398	$ 4.1398	$ 1,884,666	$ 161,451	$ 2,046,116	96,345	$ 3.8600	$ 371,896
Total	4,342,470	372,000	4,714,470	$ 4.1398	$ 4.1398	$17,976,807	$1,539,993	$ 19,516,800	854,585	$ 3.8600	$ 3,298,737
								$ 4.1398			$ 3.8600

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson Indexes Price	Emerson Indexes Cost
Nov-11	494,259	$ 3.6310	$ 1,794,654	85,304	$ 3.4860	$ 297,370
Dec-11	1,241,984	$ 4.0440	$ 5,022,583	229,242	$ 3.9515	$ 905,850
Jan-12	1,241,984	$ 4.1910	$ 5,205,155	229,242	$ 4.0160	$ 920,636
Feb-12	1,241,984	$ 4.2190	$ 5,239,930	214,452	$ 4.0365	$ 865,635
Mar-12	494,259	$ 4.1105	$ 2,031,652	96,345	$ 3.9580	$ 381,334
Total	4,714,470	$ 4.0925	$19,293,975	854,585	$ 3.9444	$ 3,370,824

Total AECO Storage Volumes	Total AECO Storage WACOG	Total AECO Storage Cost	Total Emerson WACOG	Total Emerson Cost
85,304	$ 3.8600	$ 329,277	$ 3.4860	$ 297,370
229,242	$ 3.8600	$ 884,885	$ 3.9515	$ 905,850
229,242	$ 3.8600	$ 884,885	$ 4.0160	$ 920,636
214,452	$ 3.8600	$ 827,795	$ 4.0365	$ 865,635
96,345	$ 3.8600	$ 371,896	$ 3.9580	$ 381,334
854,585	$ 3.8600	$ 3,298,737	$ 3.9444	$ 3,370,824

Max NNG Storage (Storage plan withdrawals through Apr 12) 4,714,470 5,069,321
Max AECO Storage 854,585

10/31/11 Storage Balance - NNG (estimate) 5,069,321 100.00% 4,714,470
10/31/11 Storage Balance - AECO (estimate) 947,820

Month/ Year	K#118657 NNG Storage	Storage K#122800 LS Power	Total NNG Storage	NNG PNG Volumes	NNG NMU Volumes	NNG Total Volumes	Projected K#118657 NNG WACOG	Projected K#122800 NNG WACOG	WACOG NNG PNG Cost	WACOG NNG NMU Cost	WACOG NNG Total Cost	NNG Indexes Price	NNG Index NNG PNG Cost	NNG Index NNG NMU Cost	NNG Index NNG Total Cost
Nov-11	455,259	39,000	494,259	444,240	50,019	494,259	$ 4.1398	$ 4.1398	$ 1,839,049	$ 207,067	$ 2,046,116	$ 3.6890	$ 1,638,801	$ 184,521	$ 1,823,321
Dec-11	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.0684	$ 4,541,502	$ 511,350	$ 5,052,852
Jan-12	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.3351	$ 4,839,301	$ 544,880	$ 5,384,181
Feb-12	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.3571	$ 4,863,811	$ 547,640	$ 5,411,451
Mar-12	455,259	39,000	494,259	444,240	50,019	494,259	$ 4.1398	$ 4.1398	$ 1,839,049	$ 207,067	$ 2,046,116	$ 4.2157	$ 1,872,779	$ 210,865	$ 2,083,645
Total	4,342,470	372,000	4,714,470	4,237,365	477,105	4,714,470	$ 4.1398	$ 4.1398	$17,541,696	$ 1,975,104	$ 19,516,800	$ 4.1904	$17,756,194	$ 1,999,256	$19,755,450
									$ 4.1398	$ 4.1398	$ 4.1398		$ 4.1904	$ 4.1904	$ 4.1904

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total Nexen Volumes	GLGT/VGT Centra AECO Storage WACOG	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Storage Cost
Nov-11	85,304	13,244	22,538	12,100	21,191	16,230	85,304	$ 3.8600	$ 51,123	$ 86,999	$ 46,708	$ 81,798	$ 62,649	$ 329,277
Dec-11	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.8600	$ 137,384	$ 233,797	$ 125,521	$ 219,821	$ 168,361	$ 884,885
Jan-12	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.8600	$ 137,384	$ 233,797	$ 125,521	$ 219,821	$ 168,361	$ 884,885
Feb-12	214,452	33,295	56,661	30,420	53,274	40,802	214,452	$ 3.8600	$ 128,521	$ 218,713	$ 117,422	$ 205,639	$ 157,499	$ 827,795
Mar-12	96,345	14,958	25,456	13,667	23,934	18,331	96,345	$ 3.8600	$ 57,739	$ 98,259	$ 52,753	$ 92,386	$ 70,758	$ 371,896
Total	854,585	132,680	225,792	121,223	212,294	162,596	854,585	$ 3.8600	$ 512,152	$ 871,566	$ 467,925	$ 819,464	$ 627,629	$ 3,298,737
		15.53%	26.42%	14.18%	24.84%	19.03%	100.00%		$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total AECO Storage Volumes	Projected Emerson Index Price	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Cost
Nov-11	85,304	13,244	22,538	12,100	21,191	16,230	85,304	$ 3.4860	$ 46,169	$ 78,569	$ 42,182	$ 73,872	$ 56,579	$ 297,370
Dec-11	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.9515	$ 140,639	$ 239,337	$ 128,495	$ 225,029	$ 172,350	$ 905,850
Jan-12	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 4.0160	$ 142,935	$ 243,243	$ 130,592	$ 228,702	$ 175,163	$ 920,636
Feb-12	214,452	33,295	56,661	30,420	53,274	40,802	214,452	$ 4.0365	$ 134,396	$ 228,711	$ 122,790	$ 215,039	$ 164,699	$ 865,635
Mar-12	96,345	14,958	25,456	13,667	23,934	18,331	96,345	$ 3.9580	$ 59,205	$ 100,753	$ 54,092	$ 94,730	$ 72,554	$ 381,334
Total	854,585	132,680	225,792	121,223	212,294	162,596	854,585	$ 3.9444	523,344	890,613	478,151	837,372	641,345	3,370,824
		15.53%	26.42%	14.18%	24.84%	19.03%	100.00%		$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-11

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
1	05/31/11		14	140,000	$ 5.0000	$ 700,000	$ 3.5900	$ 502,600	$ 3.5900	$ 502,600	$ -	$ 0.3750	$ 52,500	$ 555,100
2	06/23/11		15	150,000	$ 4.5000	$ 675,000	$ 3.5900	$ 538,500	$ 3.5900	$ 538,500	$ -	$ 0.3350	$ 50,250	$ 588,750
3	07/21/11		16	160,000	$ 4.5000	$ 720,000	$ 3.5900	$ 574,400	$ 3.5900	$ 574,400	$ -	$ 0.3000	$ 48,000	$ 622,400
4	08/31/11		20	200,000	$ 4.5000	$ 900,000	$ 3.5900	$ 718,000	$ 3.5900	$ 718,000	$ -	$ 0.1030	$ 20,600	$ 738,600
5	09/15/11		20	200,000	$ 4.0000	$ 800,000	$ 3.5900	$ 718,000	$ 3.5900	$ 718,000	$ -	$ 0.1700	$ 34,000	$ 752,000
6	10/04/11		19	190,000	$ 4.0000	$ 760,000	$ 3.5900	$ 682,100	$ 3.5900	$ 682,100	$ -	$ 0.0230	$ 4,370	$ 686,470
7				-		$ -	$ -	$ -	$ 3.5900	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.5900	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.5900	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.5900	$ -	$ -		$ -	$ -
Total			104	1,040,000		$ 4,555,000		$ 3,733,600		$ 3,733,600	$ -		$ 209,720	$ 3,943,320
						$ 4.3798		$ 3.5900		$ 3.5900	$ -		$ 0.2017	$ 3.7917
NNG-PNG	76	73.08%	76	760,000	$ 4.3798	$ 3,328,654	$ 3.5900	$ 2,728,400	$ 3.5900	$ 2,728,400	$ -	$ 0.2017	$ 153,257	$ 2,881,657
NNG-NMU	9	8.65%	9	90,000	$ 4.3798	$ 394,183	$ 3.5900	$ 323,100	$ 3.5900	$ 323,100	$ -	$ 0.2017	$ 18,149	$ 341,249
GLGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5900	$ 107,700	$ 3.5900	$ 107,700	$ -	$ 0.2017	$ 6,050	$ 113,750
GLGT-NMU	5	4.81%	5	50,000	$ 4.3798	$ 218,990	$ 3.5900	$ 179,500	$ 3.5900	$ 179,500	$ -	$ 0.2017	$ 10,083	$ 189,583
VGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5900	$ 107,700	$ 3.5900	$ 107,700	$ -	$ 0.2017	$ 6,050	$ 113,750
VGT-NMU	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5900	$ 143,600	$ 3.5900	$ 143,600	$ -	$ 0.2017	$ 8,066	$ 151,666
Centra	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5900	$ 143,600	$ 3.5900	$ 143,600	$ -	$ 0.2017	$ 8,066	$ 151,666
Total	104	100.0%	104	1,040,000	$ 4.3798	$ 4,555,000	$ 3.5900	$ 3,733,600	$ 3.5900	$ 3,733,600	$ -	$ 0.2017	$ 209,720	$ 3,943,320
														$ 3.7917

Dec-11

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
1	05/31/11		22	220,000	$ 5.5000	$ 1,210,000	$ 3.9230	$ 863,060	$ 3.9230	$ 863,060	$ -	$ 0.2880	$ 63,360	$ 926,420
2	06/30/11		22	220,000	$ 5.0000	$ 1,100,000	$ 3.9230	$ 863,060	$ 3.9230	$ 863,060	$ -	$ 0.2750	$ 60,500	$ 923,560
3	07/25/11		21	210,000	$ 5.0000	$ 1,050,000	$ 3.9230	$ 823,830	$ 3.9230	$ 823,830	$ -	$ 0.1980	$ 41,580	$ 865,410
4	08/03/11		25	250,000	$ 4.5000	$ 1,125,000	$ 3.9230	$ 980,750	$ 3.9230	$ 980,750	$ -	$ 0.2670	$ 66,750	$ 1,047,500
5	09/23/11		25	250,000	$ 4.0000	$ 1,000,000	$ 3.9230	$ 980,750	$ 3.9230	$ 980,750	$ -	$ 0.2180	$ 54,500	$ 1,035,250
6	10/07/11		28	280,000	$ 4.0000	$ 1,120,000	$ 3.9230	$ 1,098,440	$ 3.9230	$ 1,098,440	$ -	$ 0.1100	$ 30,800	$ 1,129,240
7				-		$ -	$ -	$ -	$ 3.9230	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9230	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9230	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9230	$ -	$ -		$ -	$ -
Total			143	1,430,000		$ 6,605,000		$ 5,609,890		$ 5,609,890	$ -		$ 317,490	$ 5,927,380
						$ 4.6189		$ 3.9230		$ 3.9230	$ -		$ 0.2220	$ 4.1450
NNG-PNG	105	73.43%	105	1,050,000	$ 4.6189	$ 4,849,825	$ 3.9230	$ 4,119,150	$ 3.9230	$ 4,119,150	$ -	$ 0.2220	$ 233,122	$ 4,352,272
NNG-NMU	13	9.09%	13	130,000	$ 4.6189	$ 600,455	$ 3.9230	$ 509,990	$ 3.9230	$ 509,990	$ -	$ 0.2220	$ 28,863	$ 538,853
GLGT-PNG	4	2.80%	4	40,000	$ 4.6189	$ 184,755	$ 3.9230	$ 156,920	$ 3.9230	$ 156,920	$ -	$ 0.2220	$ 8,881	$ 165,801
GLGT-NMU	7	4.90%	7	70,000	$ 4.6189	$ 323,322	$ 3.9230	$ 274,610	$ 3.9230	$ 274,610	$ -	$ 0.2220	$ 15,541	$ 290,151
VGT-PNG	3	2.10%	3	30,000	$ 4.6189	$ 138,566	$ 3.9230	$ 117,690	$ 3.9230	$ 117,690	$ -	$ 0.2220	$ 6,661	$ 124,351
VGT-NMU	6	4.20%	6	60,000	$ 4.6189	$ 277,133	$ 3.9230	$ 235,380	$ 3.9230	$ 235,380	$ -	$ 0.2220	$ 13,321	$ 248,701
Centra	5	3.50%	5	50,000	$ 4.6189	$ 230,944	$ 3.9230	$ 196,150	$ 3.9230	$ 196,150	$ -	$ 0.2220	$ 11,101	$ 207,251
Total	143	100.0%	143	1,430,000	$ 4.6189	$ 6,605,000	$ 3.9230	$ 5,609,890	$ 3.9230	$ 5,609,890	$ -	$ 0.2220	$ 317,490	$ 5,927,380
														$ 4.1450

Jan-12

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
1	05/27/11		21	210,000	$ 5.5000	$ 1,155,000	$ 4.0420	$ 848,820	$ 4.0420	$ 848,820	$ -	$ 0.3150	$ 66,150	$ 914,970
2	06/17/11		25	250,000	$ 5.0000	$ 1,250,000	$ 4.0420	$ 1,010,500	$ 4.0420	$ 1,010,500	$ -	$ 0.3900	$ 97,500	$ 1,108,000
3	07/26/11		27	270,000	$ 5.0000	$ 1,350,000	$ 4.0420	$ 1,091,340	$ 4.0420	$ 1,091,340	$ -	$ 0.2600	$ 70,200	$ 1,161,540
4	08/31/11		28	280,000	$ 4.5000	$ 1,260,000	$ 4.0420	$ 1,131,760	$ 4.0420	$ 1,131,760	$ -	$ 0.3150	$ 88,200	$ 1,219,960
5	09/29/11		30	300,000	$ 4.5000	$ 1,350,000	$ 4.0420	$ 1,212,600	$ 4.0420	$ 1,212,600	$ -	$ 0.1390	$ 41,700	$ 1,254,300
6	10/18/11		31	310,000	$ 4.0000	$ 1,240,000	$ 4.0000	$ 1,240,000	$ 4.0420	$ 1,253,020	$ (13,020)	$ 0.2050	$ 63,550	$ 1,303,550
7				-		$ -	$ -	$ -	$ 4.0420	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 4.0420	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 4.0420	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 4.0420	$ -	$ -		$ -	$ -
Total	Total		162	1,620,000		$ 7,605,000		$ 6,535,020		$ 6,548,040	$ (13,020)		$ 427,300	$ 6,962,320
						$ 4.6944		$ 4.0340		$ 4.0420	$ (0.0080)		$ 0.2638	$ 4.2977
NNG-PNG	117	72.22%	117	1,170,000	$ 4.6944	$ 5,492,500	$ 4.0340	$ 4,719,737	$ 4.0420	$ 4,729,140	$ -	$ 0.2638	$ 308,606	$ 5,028,342
NNG-NMU	15	9.26%	15	150,000	$ 4.6944	$ 704,167	$ 4.0340	$ 605,094	$ 4.0420	$ 606,300	$ -	$ 0.2638	$ 39,565	$ 644,659
GLGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 4.0340	$ 161,359	$ 4.0420	$ 161,680	$ -	$ 0.2638	$ 10,551	$ 171,909
GLGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 4.0340	$ 322,717	$ 4.0420	$ 323,360	$ -	$ 0.2638	$ 21,101	$ 343,818
VGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 4.0340	$ 161,359	$ 4.0420	$ 161,680	$ -	$ 0.2638	$ 10,551	$ 171,909
VGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 4.0340	$ 322,717	$ 4.0420	$ 323,360	$ -	$ 0.2638	$ 21,101	$ 343,818
Centra	6	3.70%	6	60,000	$ 4.6944	$ 281,667	$ 4.0340	$ 242,038	$ 4.0420	$ 242,520	$ -	$ 0.2638	$ 15,826	$ 257,864
Total	162	100.0%	162	1,620,000	$ 4.6944	$ 7,605,000	$ 4.0340	$ 6,535,020	$ 4.0420	$ 6,548,040	$ -	$ 0.2638	$ 427,300	$ 6,962,320
														$ 4.2977

Feb-12

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
1	05/27/11		20	200,000	$ 5.5000	$ 1,100,000	$ 4.0530	$ 810,600	$ 4.0530	$ 810,600	$ -	$ 0.3250	$ 65,000	$ 875,600
2	06/17/11		21	210,000	$ 5.0000	$ 1,050,000	$ 4.0530	$ 851,130	$ 4.0530	$ 851,130	$ -	$ 0.4080	$ 85,680	$ 936,810
3	07/27/11		23	230,000	$ 5.0000	$ 1,150,000	$ 4.0530	$ 932,190	$ 4.0530	$ 932,190	$ -	$ 0.3000	$ 69,000	$ 1,001,190
4	08/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 4.0530	$ 972,720	$ 4.0530	$ 972,720	$ -	$ 0.2740	$ 65,760	$ 1,038,480
5	09/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 4.0530	$ 972,720	$ 4.0530	$ 972,720	$ -	$ 0.1620	$ 38,880	$ 1,011,600
6	10/19/11		27	270,000	$ 4.0000	$ 1,080,000	$ 4.0000	$ 1,080,000	$ 4.0530	$ 1,094,310	$ (14,310)	$ 0.2650	$ 71,550	$ 1,151,550

Mar-12

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
1	05/27/11		14	140,000	$ 5.5000	$ 770,000	$ 4.0200	$ 562,800	$ 4.0200	$ 562,800	$ -	$ 0.3450	$ 48,300	$ 611,100
2	06/30/11		17	170,000	$ 5.0000	$ 850,000	$ 4.0200	$ 683,400	$ 4.0200	$ 683,400	$ -	$ 0.3900	$ 66,300	$ 749,700
3	07/26/11		18	180,000	$ 5.0000	$ 900,000	$ 4.0200	$ 723,600	$ 4.0200	$ 723,600	$ -	$ 0.3100	$ 55,800	$ 779,400
4	08/24/11		21	210,000	$ 4.5000	$ 945,000	$ 4.0200	$ 844,200	$ 4.0200	$ 844,200	$ -	$ 0.2800	$ 58,800	$ 903,000
5	09/28/11		21	210,000	$ 4.5000	$ 945,000	$ 4.0200	$ 844,200	$ 4.0200	$ 844,200	$ -	$ 0.2100	$ 44,100	$ 888,300
6	10/17/11		21	210,000	$ 4.0000	$ 840,000	$ 4.0000	$ 840,000	$ 4.0200	$ 844,200	$ (4,200)	$ 0.3290	$ 69,090	$ 909,090

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
1			91	910,000	$ 5.4231	$ 4,935,000	$ 3.9427	$ 3,587,880	$ 3.9427	$ 3,587,880	$ -	$ 0.3245	$ 295,310	$ 3,883,190
2			100	1,000,000	$ 4.9250	$ 4,925,000	$ 3.9466	$ 3,946,590	$ 3.9466	$ 3,946,590	$ -	$ 0.3502	$ 350,230	$ 4,306,820
3			105	1,050,000	$ 4.9238	$ 5,170,000	$ 3.9480	$ 4,145,360	$ 3.9480	$ 4,145,360	$ -	$ 0.2710	$ 284,580	$ 4,429,940
4			118	1,180,000	$ 4.5000	$ 5,310,000	$ 3.9385	$ 4,647,430	$ 3.9385	$ 4,647,430	$ -	$ 0.2543	$ 300,110	$ 4,947,540
5			120	1,200,000	$ 4.3125	$ 5,175,000	$ 3.9402	$ 4,728,270	$ 3.9402	$ 4,728,270	$ -	$ 0.1777	$ 213,180	$ 4,941,450
6			126	1,260,000	$ 4.0000	$ 5,040,000	$ 3.9211	$ 4,940,540	$ 3.9461	$ 4,972,070	$ (31,530)	$ 0.1900	$ 239,350	$ 5,179,900