DORSEY
DORSEY & WHITNEY LLP

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

November 1, 2010

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, 2010

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

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

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

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, 2010.

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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, 2010.

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, 2010
Proposed Effective Date: November 1, 2010

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, 2010

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

David C. Boyd	Chair
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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, 2010.

[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 2010-2011 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 decreased 8,762 Mcf (or approximately 4.31 percent) from 203,360 Mcf to 194,598 Mcf.

Table 1: MERC's Proposed NNG Reserve Margins
For the 2010-2011 Heating Season
PNG/NMU

	Reserve Margin 2010-2011 Heating Season	Reserve Margin 2009-2010 Heating Season	Change
NNG Zone EF	19.92%	11.68%	8.24%

As shown in Table 1, MERC's proposed system wide reserve margin, Zone EF for the 2010-2011 heating season is positive.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day requirement for Northern Natural Gas (NNG), which includes PNG and NMU is 218,213 Dth as calculated in Attachment 5 and Attachment 7 under the NNG Entitlement Allocation.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity on Northern Natural Gas (NNG), which includes PNG and NMU is 261,675 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 19.92% positive reserve margin.

Demand Entitlement increased due to 7,000 Dth that historically was allocated to the NMU and PNG-VGT Demand Entitlements, but has been allocated to PNG-NNG and

NMU in this filing. This capacity was rarely used by PNG-VGT, and the decision was made to allocate the demand cost to the customer base that benefits from the capacity which is PNG-NNG and NMU-NNG customers. MERC also changed the allocation process by allocating all NNG and LS Power capacity to PNG-NNG and NMU-NNG customers based upon the forecasted Design Day as calculated in Attachment 5. The change in allocation process was made to address the Office of Energy Security's (OES) concern of NMU-NNG customers having a negative reserve margin.

B. Forecast Methodology for MERC Demand Entitlement Nov. 1, 2010

Peakday

Purpose

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

Background

MERC is composed of two service areas:

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

Which are served by four pipelines:

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

6. Centra - Centra pipeline (serves NMU)

Four Petitions for Change in Demand are filed (one for each of 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 seven weather stations:

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

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

	Demand Area (Service Area / Pipeline)	**PGA**	**Weather Station(s)**
1	NMU-Centra	NMU	International Falls
2	NMU-GLGT *	NMU	Bemidji & Cloquet
3	NMU-NNG	NMU	Cloquet
4	NMU-VGT *	NMU	Fargo
5	NMU-GLGT&VGT*	NMU	Bemidji
6	PNG-GLGT	PNG-GLGT	Bemidji
7	PNG-NNG	PNG-NNG	Minneapolis, Rochester, Cloquet & Worthington
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 the eight demand areas by weather station.
- Subtract the daily pipeline meter readings for all non-firm customers with daily pipeline meter readings available for all three December through February years from the total throughput for each demand area and weather station. Use the resulting net daily metered volumes for regressions. Examples of non-firm customer meter readings subtracted from the demand area total daily throughputs are paper mills, direct-connects, taconites, and off-system end users. (See "Adjusting the Regression Results to a Firm Peak Day Estimate" below.)
- Determine how to map the monthly billing data to the eight demand areas.

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

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65
Bemidji	2/1/1996	-34	8	99	107
Cloquet	2/2/1996	-31	7	96	103
Fargo	1/18/1996	-16	34	81	109
International Falls	2/2/1996	-34	8	99	107
Minneapolis	2/2/1996	-25	8	90	97
Rochester	2/2/1996	-27	10	92	101
Worthington	1/18/1996	-8	32	73	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 a more nearly ideal world, the Team would have also had daily telemetered data from each interruptible, transportation, and joint interruptible customer mapped to each of the eight demand areas and related weather stations. This was the case for a handful of paper mills, direct-connects, taconites, and off-system end users. The rest of the interruptible, transportation, and joint interruptible data was available based on monthly billing cycle data that introduces billing lag, meter read lag (not all meters were read every month, 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 eight Demand Areas (Service Area / Pipeline):
    1. Gather the net daily metered volumes and weather station data including AHDD65[2].
    2. If more than one weather station is represented in a given demand area, weight each weather station's AHDD65 by the total December through February metered volumes attributable to that weather station.
    3. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer

[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

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[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. Maximum Daily Quantity (MDQ):

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

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

While interruptible, joint interruptible and transportation customer volumes were removed (as described above), in order to determine firm peak day load, daily firm capacity selections needed to be added back. The Sales and Revenue Forecasting department provided historical monthly DFC data for the "joint interruptible" customers from January 2009 through March 2010 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 for January 2010 were then added back to the adjusted regression results.

C. Apply Sales Forecast Growth Rates

The throughput volumes used in the data regressions were from December 2007 to February 2010 and needed to be adjusted to properly forecast 2011. The sales forecast “MERC Fcst 201004”, as approved by the Gas Planning Committee, was used to determine a growth rate for each demand area. Because the Peak Day Forecast is based on firm load, General Service volumes (GS - residential, commercial and industrial firm) were used as a proxy to calculate growth rates. These growth rates were then applied to the adjusted regression results.

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

<u>NMU-GLGT</u>

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

<u>NMU-VGT</u>

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

<u>PNG-NNG</u>

Taconites / Direct Connects =

- CCI EMPIRE IND DEL PT 2 TILDEN
- CCI NORTHSHORE
- EVELETH TACONITE
- HIBBING TACONITE CO.
- U.S. STEEL
- NATIONAL STEEL PELLET

- COTTAGE GROVE TBS LS POWER
- INLAND STEEL
- HANNA MINING

PNG-NNG

OSEU (End Users) =

- CORRECTIONAL CTR
- KEMPS LLC
- KERRY BIO-SCIENCE
- LAKESIDE
- LAND OF LAKES
- PRO-CORN
- SWIFT

B. Daily Firm Capacity

PNG-VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL
- BEST WESTERN

PNG-GLGT

- AMERIPRIDE/WPS SERVICES INC
- ELDERCARE
- NORTHLAND APTS
- NW TECH COLLEGE - BEMIDJI
- BEM ISD #31-JW SMITH ELEM
- BEM ISD #31-CENTRAL ELEM

PNG-NNG

- HENDRICKS HOSPITAL
- GLASSTITE INC
- SHANNON GLEN CONDO III
- SHANNON GLEN CONDO I
- SHANNON GLEN CONDO II
- SHANNON GLEN CONDO IV

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

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC-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 an increase of 2,563 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	7,361 Mcf/Day
TF5	(834) Mcf/Day
TFX12	(2,397) Mcf/Day
TFX5	(1,143) Mcf/Day
LS Power	(424) Mcf/Day
Total Overall Change	2,563 Mcf/Day

MERC contracted for capacity on Bison Pipeline for 50,000 Dth/day with a projected in-service date of December 15, 2010 at Northern Border Pipeline (NBPL). The PNG-NNG allocated share of this capacity is 44,589 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 a decrease 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 2010/2011 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 $1,876,399 for the 2010/2011 winter. Please see Attachment 8.

iii. MERC entered into 472 contracts (10,000/contract) or 4,720,000. Total premium per contract is approximately $0.3975. 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 204 futures contracts (10,000/contract) or 2,040,000.

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 2010-2011 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 $4.9275. Please see Attachment 15, page 1 of 3. MERC is projecting the NNG Storage WACOG for PNG-NNG to be approximately $4.0923. 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 $5.01, 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 $4.35 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $5.01 strike price plus the physical index basis spread. If the NYMEX prices are below the average $5.01 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, 2010. Rate impacts associated with this change can be found on Attachment 4, pages 1 through 3, and on page 1 of Attachment 11. MERC has also calculated the rate impact of moving the cost recovery of FDD Storage contracts from the demand cost recovery portion of the monthly PGA to the commodity cost recovery portion of the monthly PGA. Attachment 4, pages 4 through 6, and Attachment 11, page 2, illustrate the rate impact created by this shift in cost recovery.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2010. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2010

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Sarah J. Sorenson, being first duly sworn on oath, deposes and states that on the 1st day of November, 2010, the Petition of Minnesota Energy Resources Corporation was electronically filed with the Minnesota Public Utilities Commission and the Minnesota Department of Commerce. A copy of the filing was provided via United States first class mail to the individuals on the attached service list at the Office of the Attorney General, and a summary of the filing was provided via United States first class mail to the remaining individuals on the attached service list.

/s/ Sarah J. Sorenson

Subscribed and sworn to before me
this 1st day of November, 2010.

/s/ Paula R. Bjorkman
Notary Public, State of Minnesota

Burl W. Haar
MN Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101-5147

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-PNG

Demand Entitlement Schedules - NNG

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND SUMMARY

NOVEMBER 1, 2010

NNG

Design Day Requirement		194,598
Total Peak Day Entitlement		233,627
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 4)	151,937
Firm Annual Throughput - Minnesota		19,922,894
No. of Firm Customers		158,298
Department Load Factor Calculation		35.92%

MINNESOTA ENERGY RESOURCES - PNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2010
NNG

Pipeline Group	Nov09-Mar 10 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	Nov09-Mar 10 Avg. Customer Growth	Total *
PEAK										
PNG	158,298	158,298	99	26,150	2,217	259,378	64,651	194,727	-0.10%	194,598
Total	158,298	158,298								194,598
OFF PEAK										
PNG	158,298	158,298	55	26,150	2,217	161,224	41,677	119,547	-0.10%	119,468
Total	158,298	158,298								119,468

* 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, 2010

		NNG	
Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
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
04/05	143,896	207,834	1.44

MINNESOTA ENERGY RESOURCES - PNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2010

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	5,507,757	14,415,137	19,922,894
SVI	899,643	1,668,434	2,568,077
SVJ	0	0	0
LVI	298,069	420,332	718,401
LVJ	0	0	0
SLV	0	0	0
Total	6,705,469	16,503,903	23,209,372

MINNESOTA ENERGY RESOURCES - PNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2010

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
TF-12 Base & Variable	59,804	7,361	67,165
TF5	29,619	(834)	28,785
TFX - 12	31,199	(2,397)	28,802
TFX - 5	81,567	(1,143)	80,424
TFX- (Apr) Offpeak*	2,000	(216)	1,784
TFX- (Oct) Offpeak*	2,000	(216)	1,784
Bison	0	44,589	44,589
NBPL	0	44,589	44,589
Windom	2,500	0	2,500
LSP Peaking Service	26,375	(424)	25,951
Heating Season Total	**231,064**	**2,563**	**233,627**
Non-Heating Season Total	95,503	4,748	100,251
Heating Season Forecasted Design Day-Adjusted	203,360	(8,762)	194,598
Non-Heating Season Forecasted Design Day	126,892	(7,424)	119,468
Heating Season Capacity Surplus/Shortage	27,704	11,325	39,029
Non-Heating Season Capacity Surplus/Shortage	(31,389)	12,172	(19,217)

*Not included in Heating Season Total entitlement

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2010
NNG

All costs in $/MMBtu	Last Base Cost of Gas G007, G011/ MR08-836* 8-Oct	Last Demand Change G011- M-08- Oct .08	Last Demand Change G011- M-09- Oct. 09	Most Recent PGA Oct. 2010	Current Proposal Effective Nov.1,2010	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service: Avg. Annual Use:		**125**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	($4.6416)	$0.3199	3.34%	$0.1312
Demand Cost	$1.1197	$1.0903	$1.0883	$1.0362	$1.6626	$0.5429	$0.5743	60.45%	$0.6264
Commodity Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	$0.1483	$0.1483	0.00%	$0.0000
Total Cost of Gas	$11.4474	$8.6958	$6.4545	$6.7394	$7.4970	($3.9504)	$1.0425	11.24%	$0.7576
Avg Annual Cost	$1,429.40	$1,085.82	$805.95	$841.53	$936.13	($493.27)	$130.18	11.24%	$94.60
Effect of proposed commodity change on average annual bills:									$16.39
Effect of proposed demand change on average annual bills:									$78.22
2) Small Vol. Interruptible: Avg. Annual Use:		**4,080**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	($4.6416)	$0.3199	3.34%	$0.1312
Demand Cost	$0.0000								
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	($0.0753)	($0.0753)	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.2226	$4.9833	$5.0967	$5.2279	($4.7169)	$0.2446	2.57%	$0.1312
Avg Annual Cost	$40,572.00	$29,466.19	$20,330.47	$20,793.11	$21,328.46	($19,243.54)	$997.99	2.57%	$535.35
Effect of proposed commodity change on average annual bills:									$535.35
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**19,053**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	($4.6416)	$0.3199	3.34%	$0.1312
Demand Cost									
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	($0.0344)	($0.0344)	0.00%	$0.0000
Total Cost of Gas	$9.0606	$6.3384	$4.0991	$4.2534	$4.3846	($4.6760)	$0.2855	3.09%	$0.1312
Avg Annual Cost	$172,633.79	$120,767.06	$78,101.14	$81,041.05	$83,541.25	($89,092.54)	$5,440.11	3.09%	$2,500.20
Effect of proposed commodity change on average annual bills:									$2,500.20
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,080**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	($4.6416)	$0.3199	3.34%	$0.1312
Demand Cost	$13.4177	$12.0195	$10.3925	$9.3592	$10.7565	($2.6612)	$0.3640	14.93%	$1.3973
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	($0.0753)	($0.0753)	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$2.0724	$2.0724	$1.8000	($0.2724)	($0.2724)	-13.14%	($0.2724)
Total Cost of Gas	$9.9448	$7.2226	$4.9833	$5.0967	$5.2279	($4.7169)	$0.2446	2.57%	$0.1312
Total Demand Cost	$15.4901	$14.0919	$12.4649	$11.4316	$12.5565	($2.9336)	$0.0916	9.84%	$1.1249
Avg Annual Cost	$40,959.25	$29,818.48	$20,642.09	$21,078.90	$21,642.37	($19,316.88)	$1,000.28	2.67%	$563.47
Effect of proposed commodity change on average annual bills:									$535.35
Effect of proposed demand change on average annual bills:									$34.93
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	($4.6416)	$0.3199	3.34%	$0.1312
Demand Cost	$13.4177	$12.0195	$10.3925	$9.3592	$10.7565	($2.6612)	$0.3640	14.93%	$1.3973
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	($0.0344)	($0.0344)	0.00%	$0.0000
Demand Margin	$0.1658	$1.6579	$1.6579	$1.6579	$1.4000	$1.2342	($0.2579)	-15.56%	($0.2579)
Total Cost of Gas	$9.0606	$6.3384	$4.0991	$4.2534	$4.3846	($4.6760)	$0.2855	3.09%	$0.1312
Total Demand Cost	$13.5835	$13.6774	$12.0504	$11.0171	$12.1565	($1.4270)	$0.1061	10.34%	$1.1394
Avg Annual Cost	$135,487.13	$95,094.00	$61,738.52	$63,950.99	$65,983.91	($19,112.36)	$4,245.38	3.18%	$2,032.92
Effect of proposed commodity change on average annual bills:									$1,947.46
Effect of proposed demand change on average annual bills:									$104.80

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

*Implemented with Interim rates

**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2010

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					$4.0489

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	29,675	12	$7.5776	=	$2,698,383	$0.01396
	TF12V (Max Rate)	112495	32,290	12	$9.0926	=	$3,523,201	$0.01822
	TF5 (Max Rate)	112495	28,785	5	$15.1530	=	$2,180,896	$0.01128
	TF12B (Discount-Winter)	112495	5,200	12	$6.4818	=	$404,464	$0.00209
	TF5 (Discount-Winter)	112495	0	5	$7.6000	=	$0	$0.00000
	TFX5 (Discount)	112561	5,351	5	$4.5600	=	$122,003	$0.00063
	TFX12 (Max Rate)	112486	9,651	12	$9.6288	=	$1,115,131	$0.00577
	TFX Apr (Max Rate)	112486	1,784	1	$5.6830	=	$10,138	$0.00005
	TFX Oct (Max Rate)	112486	1,784	1	$5.6830	=	$10,138	$0.00005
	TFX5 (Max Rate)	112486	51,163	5	$15.1530	=	$3,876,365	$0.02005
	TFX5 (Discount)	112486	0	5	$13.8736	=	$0	$0.00000
	TFX5 (Discount)	112486	1,605	5	$7.6050	=	$61,030	$0.00032
	TFX12 (Discount)	111866	1,144	12	$4.8640	=	$66,773	$0.00035
	TFX12 (Discount)	111866	7,376	12	$5.4720	=	$484,338	$0.00251
	TFX12 (Discount)	111866	10,631	12	$2.2192	=	$283,108	$0.00146
	TFX5 (Discount)	111866	338	5	$4.8640	=	$8,220	$0.00004
	TFX5 (Discount)	111866	2,180	5	$5.4720	=	$59,645	$0.00031
	TFX5 (Discount)	111866	19,788	5	$15.1392	=	$1,497,872	$0.00775
	SMS	112521	20,226	12	$2.1800	=	$529,112	$0.00274
	Bison	FT0003	44,589	10.5	$17.4800	=	$8,183,865	$0.04233
	NBPL	T8673F	44,589	10.5	$6.9920	=	$3,273,546	$0.01693
	LS Power		25,951	3	$4.3463	=	$338,369	$0.00175
	WINDOM		2,500	12	$0.0000	=	$0	$0.00000
FDD:	Storage Reservation	118657	67,273	12	$1.7140	=	$1,383,671	$0.00716
	Storage Cycle Volume	118657	775,728	5	$0.3567	=	$1,383,511	$0.00716
	Storage Reservation	118657	4,949	12	$3.3157	=	$196,913	$0.00102
	Storage Cycle Volume	118657	57,074	5	$0.6901	=	$196,934	$0.00102
	Storage Reservation	121292	6,187	12	$1.7140	=	$127,254	$0.00066
	Storage Cycle Volume	121292	71,342	5	$0.3567	=	$127,238	$0.00066
	Total Demand Cost						$32,142,118	$0.16626
	Rate Case 2008 volume in Ccf						193,321,000	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.16626**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.40598**
	Total GS-1 Current Cost of Gas/Ccf							**$0.57224**

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	$4.0489	$86,297,295.01	213,137,630	$0.40489
Call Option Premium				$ 232,781	213,137,630	$0.00109
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$ 86,530,076	213,137,630	$0.40598
CURRENT FIRM TRANSPORTATION COST OF GAS (CCF)						$0.75776

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C) $1.07565 $1.07565

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2010

NNG

COSTS ASSIGNED IN COMMODITY:

Canadian Contracts		Units (b)	Cost/Unit	Day/Mo	Cost (d)	$/Ccf
Upstream:						
Great Lakes		0	$3.458	12	$0	$0.00000
						$0.00000
Storage:	Contract #					
FDD Withdrawal	118657	4,164,007	$0.0149		$62,044	$0.00029
FDD Injection	118657	4,164,007	$0.0149		$62,044	$0.00029
FDD Withdrawal	121292	356,712	$0.0149		$5,315	$0.00002
FDD Injection	121292	300,000	$0.0149		$4,470	$0.00002
						$0.00063
Call Option Premiums		4,720,000	$0.3975		$1,876,399	$0.00880
Total Commodity Costs					$2,010,272	$0.00943

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	29,675	112495	12	$7.5776	=	$2,698,383	$0.09030
TF12V (Max Rate)	32,290	112495	12	$9.0926	=	$3,523,201	$0.11791
TF5 (Max Rate)	28,785	112495	5	$15.1530	=	$2,180,896	$0.07298
TF12B (Discount-Winter)	5,200	112495	12	$6.4818	=	$404,464	$0.01354
TF5 (Discount-Winter)	0	112495	5	$7.6000	=	$0	$0.00000
TFX5 (Discount)	5,351	112561	5	$4.5600	=	$122,003	$0.00408
TFX12 (Max Rate)	9,651	112486	12	$9.6288	=	$1,115,131	$0.03732
TFX Apr (Max Rate)	1,784	112486	1	$5.6830	=	$10,138	$0.00034
TFX Oct (Max Rate)	1,784	112486	1	$5.6830	=	$10,138	$0.00034
TFX5 (Max Rate)	51,163	112486	5	$15.1530	=	$3,876,365	$0.12972
TFX5 (Discount)	0	112486	5	$13.8736	=	$0	$0.00000
TFX5 (Discount)	1,605	112486	5	$7.6050	=	$61,030	$0.00204
TFX12 (Discount)	1,144	111866	12	$4.8640	=	$66,773	$0.00223
TFX12 (Discount)	7,376	111866	12	$5.4720	=	$484,338	$0.01621
TFX12 (Discount)	10,631	111866	12	$2.2192	=	$283,108	$0.00947
TFX5 (Discount)	338	111866	5	$4.8640	=	$8,220	$0.00028
TFX5 (Discount)	2,180	111866	5	$5.4720	=	$59,645	$0.00200
TFX5 (Discount)	19,788	111866	5	$15.1392	=	$1,497,872	$0.05013
SMS	20,226	112521	12	$2.1800	=	$529,112	$0.01771
Bison	44,589	FT0003	10.5	$17.4800	=	$8,183,865	$0.27388
NBPL	44,589	T8673F	10.5	$6.9920	=	$3,273,546	$0.10955
LS Power	25,951		3	$4.3463	=	$338,369	$0.01132
WINDOM	2,500		12	$0.0000	=	$0	$0.00000
Storage Reservation	67,273	118657	12	$1.7140	=	$1,383,671	$0.04631
Storage Cycle Volume	775,728	118657	5	$0.3567	=	$1,383,511	$0.04630
Storage Reservation	4,949	118657	12	$3.3157	=	$196,913	$0.00659
Storage Cycle Volume	57,074	118657	5	$0.6901	=	$196,934	$0.00659
Storage Reservation	6,187	121292	12	$1.7140	=	$127,254	$0.00426
Storage Cycle Volume	71,342	121292	5	$0.3567	=	$127,238	$0.00426
				TOTAL		$32,142,118	
				Annualized Entitlement		29,881,560	
				Demand Component		$1.07565	$1.07565

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, 2010

NNG

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-08- Oct .08	Last Demand Change G011- M-09- Oct. 09	Most Recent PGA Oct. 2010	Current Proposal Effective Nov.1,2010	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:		**125**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	($4.4813)	$0.4802	7.42%	$0.2915
Demand Cost	$1.1197	$1.0903	$1.0883	$1.0362	$1.4860	$0.3663	$0.3977	43.40%	$0.4498
Commodity Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	$0.1483	$0.1483	0.00%	$0.0000
Total Cost of Gas	$11.4474	$8.6958	$6.4545	$6.7394	$7.4806	($3.9668)	$1.0261	11.00%	$0.7412
Avg Annual Cost	$1,429.40	$1,085.82	$805.96	$841.53	$934.08	($495.32)	$128.13	11.00%	$92.55
Effect of proposed commodity change on average annual bills:									$36.40
Effect of proposed demand change on average annual bills:									$56.16
2) Small Vol. Interruptible: Avg. Annual Use:		**4,080**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	($4.4813)	$0.4802	7.42%	$0.2915
Demand Cost	$0.0000								
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	($0.0753)	($0.0753)	0.00%	$0.0000
Total Cost of Gas	$9.9448	$7.2226	$4.9833	$5.0967	$5.3882	($4.5566)	$0.4049	5.72%	$0.2915
Avg Annual Cost	$40,572.00	$29,466.19	$20,330.47	$20,793.11	$21,982.23	($18,589.77)	$1,651.76	5.72%	$1,189.12
Effect of proposed commodity change on average annual bills:									$1,189.12
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**19,053**		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	($4.4813)	$0.4802	7.42%	$0.2915
Demand Cost									
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	($0.0344)	($0.0344)	0.00%	$0.0000
Total Cost of Gas	$9.0606	$6.3384	$4.0991	$4.2534	$4.5449	($4.5157)	$0.4458	6.85%	$0.2915
Avg Annual Cost	$172,633.79	$120,767.06	$78,101.14	$81,041.05	$86,594.52	($86,039.26)	$8,493.39	6.85%	$5,553.47
Effect of proposed commodity change on average annual bills:									$5,553.47
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,080**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	($4.4813)	$0.4802	7.42%	$0.2915
Demand Cost	$13.4177	$12.0195	$10.3925	$9.3592	$15.8792	$2.4615	$5.4867	69.66%	$6.5200
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	($0.0753)	($0.0753)	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$2.0724	$2.0724	$1.8000	($0.2724)	($0.2724)	-13.14%	($0.2724)
Total Cost of Gas	$9.9448	$7.2226	$4.9833	$5.0967	$5.3882	($4.5566)	$0.4049	5.72%	$0.2915
Total Demand Cost	$15.4901	$14.0919	$12.4649	$11.4316	$17.6792	$2.1891	$5.2143	54.65%	$6.2476
Avg Annual Cost	$40,959.25	$29,818.48	$20,642.09	$21,078.90	$22,424.21	($18,535.04)	$1,782.12	6.38%	$1,345.31
Effect of proposed commodity change on average annual bills:									$1,189.12
Effect of proposed demand change on average annual bills:									$163.00
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	($4.4813)	$0.4802	7.42%	$0.2915
Demand Cost	$13.4177	$12.0195	$10.3925	$9.3592	$15.8792	$2.4615	$5.4867	69.66%	$6.5200
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	($0.0344)	($0.0344)	0.00%	$0.0000
Demand Margin	$0.1658	$1.6579	$1.6579	$1.6579	$1.4000	$1.2342	($0.2579)	-15.56%	($0.2579)
Total Cost of Gas	$9.0606	$6.3384	$4.0991	$4.2534	$4.5449	($4.5157)	$0.4458	6.85%	$0.2915
Total Demand Cost	$13.5835	$13.6774	$12.0504	$11.0171	$17.2792	$3.6957	$5.2288	56.84%	$6.2621
Avg Annual Cost	$135,487.13	$95,094.00	$61,738.52	$63,950.99	$68,746.37	($18,330.52)	$7,007.85	7.50%	$4,795.38
Effect of proposed commodity change on average annual bills:									$4,325.72
Effect of proposed demand change on average annual bills:									$489.00

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

*Implemented with Interim rates

**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

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

NOVEMBER 1, 2010

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					$4.0489

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	29,675	12	$7.5776	=	$2,698,383	$0.01396
	TF12V (Max Rate)	112495	32,290	12	$9.0926	=	$3,523,201	$0.01822
	TF5 (Max Rate)	112495	28,785	5	$15.1530	=	$2,180,896	$0.01128
	TF12B (Discount-Winter)	112495	5,200	12	$6.4818	=	$404,464	$0.00209
	TF5 (Discount-Winter)	112495	0	5	$7.6000	=	$0	$0.00000
	TFX5 (Discount)	112561	5,351	5	$4.5600	=	$122,003	$0.00063
	TFX12 (Max Rate)	112486	9,651	12	$9.6288	=	$1,115,131	$0.00577
	TFX Apr (Max Rate)	112486	1,784	1	$5.6830	=	$10,138	$0.00005
	TFX Oct (Max Rate)	112486	1,784	1	$5.6830	=	$10,138	$0.00005
	TFX5 (Max Rate)	112486	51,163	5	$15.1530	=	$3,876,365	$0.02005
	TFX5 (Discount)	112486	0	5	$13.8736	=	$0	$0.00000
	TFX5 (Discount)	112486	1,605	5	$7.6050	=	$61,030	$0.00032
	TFX12 (Discount)	111866	1,144	12	$4.8640	=	$66,773	$0.00035
	TFX12 (Discount)	111866	7,376	12	$5.4720	=	$484,338	$0.00251
	TFX12 (Discount)	111866	10,631	12	$2.2192	=	$283,108	$0.00146
	TFX5 (Discount)	111866	338	5	$4.8640	=	$8,220	$0.00004
	TFX5 (Discount)	111866	2,180	5	$5.4720	=	$59,645	$0.00031
	TFX5 (Discount)	111866	19,788	5	$15.1392	=	$1,497,872	$0.00775
	SMS	112521	20,226	12	$2.1800	=	$529,112	$0.00274
	Bison	FT0003	44,589	10.5	$17.4800	=	$8,183,865	$0.04233
	NBPL	T8673F	44,589	10.5	$6.9920	=	$3,273,546	$0.01693
	LS Power		25,951	3	$4.3463	=	$338,369	$0.00175
	WINDOM		2,500	12	$0.0000	=	$0	$0.00000
	Total Demand Cost						$28,726,597	**$0.14860**
	Rate Case 2008 volume in Ccf						193,321,000	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.14860**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.42201**
	Total GS-1 Current Cost of Gas/Ccf							**$0.57060**

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	67,273	12	$1.7140	=	$1,383,671	$0.00649
	FDD - Storage Cycle	118657	775,728	5	$0.3567	=	$1,383,511	$0.00649
	FDD - Reservation	118657	4,949	12	$3.3157	=	$196,913	$0.00092
	FDD - Storage Cycle	118657	57,074	5	$0.6901	=	$196,934	$0.00092
	FDD - Reservation	121292	6,187	12	$1.7140	=	$127,254	$0.00060
	FDD - Storage Cycle	121292	71,342	5	$0.3567	=	$127,238	$0.00060
	Firm Deferred Delivery Storage Contracts						$3,415,521	$0.01602

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	21,313,763	x	$4.0489	$86,297,295	213,137,630	$0.40489
Call Option Premium				$232,781	213,137,630	$0.00109
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$89,945,597	213,137,630	**$0.42201**
CURRENT FIRM TRANSPORTATION COST OF GAS (CCF)						$0.75776

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C) $1.58792 $1.58792

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, 2010

NNG

COSTS ASSIGNED IN COMMODITY:						
Canadian Contracts		Units (b)	Cost/Unit	Day/Mo	Cost (d)	$/Ccf
Upstream:						
Great Lakes		0	$3.458	12	$0	$0.00000
						$0.00000
Storage:	Contract #					
FDD Withdrawal	118657	4,164,007	$0.0149		$62,044	$0.00029
FDD Injection	118657	4,164,007	$0.0149		$62,044	$0.00029
FDD Withdrawal	121292	356,712	$0.0149		$5,315	$0.00002
FDD Injection	121292	356,712	$0.0149		$5,315	$0.00002
						$0.00063
Call Option Premiums		4,720,000	$0.3975		$1,876,399	$0.00880
Total Commodity Costs					$2,011,117	$0.00944

COSTS ASSIGNED IN JOINT RATE:	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	29,675	112495	12	$7.5776	=	$2,698,383	$0.14916
TF12V (Max Rate)	32,290	112495	12	$9.0926	=	$3,523,201	$0.19475
TF5 (Max Rate)	28,785	112495	5	$15.1530	=	$2,180,896	$0.12055
TF12B (Discount-Winter)	5,200	112495	12	$6.4818	=	$404,464	$0.02236
TF5 (Discount-Winter)	0	112495	5	$7.6000	=	$0	$0.00000
TFX5 (Discount)	5,351	112561	5	$4.5600	=	$122,003	$0.00674
TFX12 (Max Rate)	9,651	112486	12	$9.6288	=	$1,115,131	$0.06164
TFX Apr (Max Rate)	1,784	112486	1	$5.6830	=	$10,138	$0.00056
TFX Oct (Max Rate)	1,784	112486	1	$5.6830	=	$10,138	$0.00056
TFX5 (Max Rate)	51,163	112486	5	$15.1530	=	$3,876,365	$0.21427
TFX5 (Discount)	0	112486	5	$13.8736	=	$0	$0.00000
TFX5 (Discount)	1,605	112486	5	$7.6050	=	$61,030	$0.00337
TFX12 (Discount)	1,144	111866	12	$4.8640	=	$66,773	$0.00369
TFX12 (Discount)	7,376	111866	12	$5.4720	=	$484,338	$0.02677
TFX7 (Discount)	10,631	111866	12	$2.2192	=	$283,108	$0.01565
TFX5 (Discount)	338	111866	5	$4.8640	=	$8,220	$0.00045
TFX5 (Discount)	2,180	111866	5	$5.4720	=	$59,645	$0.00330
TFX5 (Discount)	19,788	111866	5	$15.1392	=	$1,497,872	$0.08280
SMS	20,226	112521	12	$2.1800	=	$529,112	$0.02925
Bison	44,589	FT0003	10.5	$17.4800	=	$8,183,865	$0.45238
NBPL	44,589	T8673F	10.5	$6.9920	=	$3,273,546	$0.18095
LS Power	25,951		3	$4.3463	=	$338,369	$0.01870
WINDOM	2,500		12	$0.0000	=	$0	$0.00000
Storage Reservation	67,273	118657	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	775,728	118657	0	$0.3567	=	$0	$0.00000
Storage Reservation	4,949	118657	0	$3.3157	=	$0	$0.00000
Storage Cycle Volume	57,074	118657	0	$0.6901	=	$0	$0.00000
Storage Reservation	6,187	121292	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	71,342	121292	0	$0.3567	=	$0	$0.00000
				TOTAL		$28,726,597	
				Annualized Entitlement		18,090,750	
				Demand Component		$1.58792	$1.58792

Attachment 5

MINNESOTA ENERGY RESOURCES

NNG Entitlement Allocation

Heating Season 2010-2011

		Total Entitlement Levels	PNG GS	NMU GS	Total
1	Design Day	218,213	194,598	23,615	218,213
2	Customer Requirements moving to Transport	-	-	-	-
3	Adjusted Design Day	218,213	194,598	23,615	218,213
			89.18%	10.82%	100.00%
5	Total Design Day Capacity	261,675	233,627	28,048	261,675
6	Less: Windom	(2,500)	(2,500)		(2,500)
7	Less: LS Power	(29,100)	(25,951)	(3,149)	(29,100)
8	Less: Chisago Delivery to Viking	0	-		-
9	Less: Contract Demand Units	0	0		-
		230,075	205,176	24,899	230,075
	Direct Assigned Entitlement				
10	TF12B (112495)	39,107	34,875	4,232	39,107
11	TF12V (112495)	36,209	32,290	3,919	36,209
12	TF5 (112495)	32,278	28,785	3,493	32,278
13	TFX12 (112486)	10,822	9,651	1,171	10,822
14	TFX April Only (112486)	2,000	1,784	216	2,000
15	TFX October Only (112486)	2,000	1,784	216	2,000
16	TFX5 (112486)	59,171	52,768	6,403	59,171
17	TFX12 (111866)	21,475	19,151	2,324	21,475
18	TFX5 (111866)	25,013	22,306	2,707	25,013
19	TFX5 (112561)	6,000	5,351	649	6,000
20	Bison (FT 0003) *	50,000	44,589	5,411	50,000
21	NBPL (T6873F) *	50,000	44,589	5,411	50,000
22	Total Winter Allocated Entitlement	230,075	205,176	24,899	230,075
23	Windom	2,500	2,500	0	2,500
24	LS Power	29,100	25,951	3,149	29,100
25	Total Design Day Capacity	261,675	233,627	28,048	261,675
26	Contract Demand				-
27	Total Design Day Capacity	261,675	233,627	28,048	261,675
			89.28%	10.72%	100.00%
	Other Entitlements not included in Peak Day Deliverability: allocation based on design day % on line 19				
28	Storage				
29	Storage MSQ - 118657	4,669,321	4,164,007	505,314	4,669,321
30	Storage MSQ - 121292	400,000	356,712	43,288	400,000
31	SMS	22,680	20,226	2,454	22,680
32	Total Entitlement	261,675	233,627	28,048	261,675
33	Design Day	218,213	194,598	23,615	218,213
34	Reserve Margin	43,462	39,029	4,433	43,462
		19.92%	20.06%	18.77%	19.92%

* 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
2010-2011

State	1/20 Design DDD	09/10 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	158,298	26,150	2,217	259,378	64,651	194,727	-0.10%	194,598
NMU	103	17,729	2,495	238	29,075	4,482	24,593	-4.00%	23,615
TOTAL		**176,027**	**28,645**	**2,455**	**288,453**	**69,133**	**219,320**		**218,213**
MERC - Non-Peak Day									
PNG	55	158,298	26,150	2,217	161,224	41,677	119,547	-0.10%	119,468
NMU	55	17,729	2,495	238	17,629	2,892	14,737	-4.00%	14,151
TOTAL		**176,027**	**28,645**	**2,455**	**178,853**	**44,569**	**134,284**		**133,619**

* Adjustment to remove interruptible and transportation volumes and add adjustment to achieve 97.5% confidence level that actual demand under design conditions will not exceed estimate.

Attachment 7

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2010-2011 VS. 2009-2010

	2010-2011 Proposed				2009-2010				Difference			
	NNG Winter	NNG PNG	NNG NMU	NNG Total	NNG Winter	NNG PNG	NNG NMU	NNG Total	Winter	PNG	NMU	Total
TF12(base)	39,107	34,875	4,232	39,107	42,734	35,221	7,513	42,734	(3,627)	(346)	(3,281)	(3,627)
TF12(variable)	36,209	32,290	3,919	36,209	29,826	24,583	5,243	29,826	6,383	7,707	(1,324)	6,383
TF12	75,316	67,165	8,151	75,316	72,560	59,804	12,756	72,560	2,756	7,361	(4,605)	2,756
Peak Capacity	-			-	-			-	-			-
TF5	32,278	28,785	3,493	32,278	31,610	29,619	1,991	31,610	668	(834)	1,502	668
TF Total	107,594	95,950	11,644	107,594	104,170	89,423	14,747	104,170	3,424	6,527	(3,103)	3,424
TFX12	32,297	28,802	3,495	32,297	31,199	31,199	-	31,199	1,098	(2,397)	3,495	1,098
TFX5	90,184	80,424	9,760	90,184	87,706	81,567	6,139	87,706	2,478	(1,143)	3,621	2,478
TFX Total	122,481	109,226	13,255	122,481	118,905	112,766	6,139	118,905	3,576	(3,540)	7,116	3,576
NNG Total	230,075	205,176	24,899	230,075	223,075	202,189	20,886	223,075	7,000	2,987	4,013	7,000
Bison	50,000	44,589	5,411	50,000	-	-	-	-	50,000	44,589	5,411	50,000
NBPL	50,000	44,589	5,411	50,000	-	-	-	-	50,000	44,589	5,411	50,000
Windom	2,500	2,500	-	2,500	2,500	2,500	-	2,500	-	-	-	-
LSP Peaking	29,100	25,951	3,149	29,100	29,100	26,375	2,725	29,100	-	(424)	424	-
									-			
Total	261,675	233,627	28,048	261,675	254,675	231,064	23,611	254,675	7,000	2,563	4,437	7,000

	NNG-Total	
	EF	TOTAL
Design Day	218,213	218,213
Capacity	261,675	261,675
Reserve Margin	43,462	43,462
	19.92%	19.92%

	NNG-PNG	
	EF	TOTAL
Design Day	194,598	194,598
Capacity	233,627	233,627
Reserve Margin	39,029	39,029
	20.06%	20.06%

	NNG-NMU	
	EF	TOTAL
Design Day	23,615	23,615
Capacity	28,048	28,048
Reserve Margin	4,433	4,433
	18.77%	18.77%

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 8

MINNESOTA ENERGY RESOURCES - PNG-NNG

Financial Options

Heating Season 2010-2011

[TRADE SECRET DATA BEGINS

Units - Gas Daily Packages

No Gas Daily Peakers were purchased

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												
9												
10												
11												
12												
13												
14												
15												
16												
17												
Total		18,000		7,419		14,194		6,429		20,968	67,009	2,040,000
		540,000		230,000		440,000		180,000		650,000		2,040,000

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		24,667		32,581		37,742		35,000		26,452	156,441	4,720,000
		740,000		1,010,000		1,170,000		980,000		820,000		4,720,000

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	**$ 0.3146**	**$ 232,781**	**$ 0.3341**	**$ 337,482**	**$ 0.4097**	**$ 479,382**	**$ 0.4618**	**$ 452,553**	**$ 0.4563**	**$ 374,202**	**$ 0.3975**	**$ 1,876,399**

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED*

10/11 Winter Portfolio Plan - MERC NNG-PNG Hedging Plan

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (PNG)

NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

Total	**4,520,719**

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 10
NNG

MINNESOTA ENERGY RESOURCES - PNG

As Proposed **08-**	M-06-1536 Peoples Mn GS	M-07-1405 Peoples Mn GS	M-08-1331 Peoples Mn GS	**M-09- Peoples Mn GS**	**M-10- Peoples Mn GS**	Proposed Change
Design Day	200,484	202,263	225,397	**203,360**	**194,598**	-8,762
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	33.79%	32.16%	30.56%	**31.50%**	**35.92%**	4.42%
Total Design Day Capacity (includes non-recallable capacity	227,526	233,785	233,785	**238,064**	**233,627**	-4,437
Less: Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
Less: LS Power	29,100	26,323	26,323	**26,375**	**25,951**	-424
Less: TF12B	42,170	7,000	7,000	**7,000**	**0**	-7,000
Less: TF5	36,772					0
Less: TFX(5)	73,190					0
Total Design Day Capacity	195,926	197,962	197,962	**202,189**	**205,176**	-2,987
Factors for All Winter Capacity	100.00%	100.00%	100.00%	**100.00%**	**100.00%**	
Allocated Entitlements in PGA						
TF12B	42,170	43,858	29,906	**35,221**	**34,875**	-346
TF12V	34,070	15,946	32,690	**24,583**	**32,290**	7,707
TF5	36,772	29,619	26,827	**29,619**	**28,785**	-834
TFX12	9,724	18,409	29,246	**31,199**	**28,802**	-2,397
TFX(5)	73,190	90,130	79,293	**81,567**	**80,424**	-1,143
TFX(5) (12-V)	0	0	0	**0**	**0**	0
TFX (October Only)	0	0	0	**0**	**1,784**	1,784
TFX (April Only)	0	0	0	**0**	**1,784**	1,784
LS Power	0	26,323	26,323	**26,375**	**25,951**	-424
Bison *	0	0	0	**0**	**44,589**	44,589
NBPL *	0	0	0	**0**	**44,589**	44,589
Peak Capacity	195,926	224,285	224,285	**228,564**	**231,127**	2,563
Total Allocated Entitlements in PGA	195,926	224,285	224,285	228,564	323,872	95,308

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

Direct Assigned Entitlements in PGA						
Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
LS Power	29,100	26,323	26,323	**0**	**0**	0
TFX (October Only)	2,000	1,784	2,000	**2,000**	**0**	-2,000
TFX (April Only)	2,000	1,784	2,000	**2,000**	**0**	-2,000
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	35,600	32,390	32,823	**6,500**	**2,500**	(4,000)
Total Capacity before Peak Shaving	231,526	256,675	257,108	**235,064**	**233,627**	-1,437
LP Peak Shaving	0	0	0	**0**	**0**	0
Total Design Day Capacity	227,526	253,108	253,108	**231,064**	**233,627**	2,563
Total Transp. (with TFX Offpeak less LSP)	198,426	226,785	226,785	**204,689**	**207,676**	2,987
Total Annual Transportation	88,464	80,713	94,342	**93,503**	**98,467**	4,964
Total Seasonal Transportation	139,062	172,395	158,766	**137,561**	**135,160**	-2,401
Total Percent Seasonal	61.1%	68.1%	62.7%	**59.5%**	**57.9%**	-1.68%
LS Power as % of Total DD Capacity	12.8%	10.4%	10.4%	**11.4%**	**11.1%**	-0.31%
Reserve Margin	13.49%	25.14%	12.29%	**13.62%**	**20.06%**	6.43%
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	0	0	0	**0**	**0**	0
Total Design Day Capacity w/ contract demand	227,526	233,785	233,785	**238,064**	**233,627**	-4,437
Factors	33.79%	32.16%	30.56%	**31.50%**	**35.92%**	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	2,000	1,784	2,000	**2,000**	**1,784**	-216
TFX Apr		1,784	1,784	**2,000**	**1,784**	-216
TFX Apr-Oct	0	0	0	**0**	**0**	0
TFX May-Sept	0	0	0	**0**	**0**	0
FDD Storage reservation	69,094	73,022	76,476	**76,628**	**78,409**	1,781
FDD Storage capacity	4,349,321	4,210,037	4,409,251	**4,417,893**	**4,520,719**	102,826
Nexen PSO	0	0	0	**0**	**0**	0
Tenaska PSO New	188,000	170,237	0	**0**	**0**	0
NGPL	0	0	0	**0**	**0**	0
SMS	22,680	20,537	20,537	**20,577**	**20,226**	-351
SBA	0	0	0	**0**		0

MINNESOTA ENERGY RESOURCES - PNG

Rate Impacts
NNG

1) General Service: Avg. Annual Use:				**125 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case^^**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	-53.34%	8.55%	3.34%	$0.1312
Demand Rate	$1.1197	$1.0903	$1.0883	$1.0362	$1.6626	48.49%	52.77%	60.45%	$0.6264
Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Recovery	$11.4474	$8.6958	$6.4545	$6.7394	$7.4970	-34.51%	16.15%	11.24%	$0.7576
Avg. Annual Bill*****	$1,429.40	$1,085.82	$805.95	$841.53	$936.13	-34.51%	16.15%	11.24%	$94.60
Effect of proposed commodity change on average annual bills:									$16.39
Effect of proposed demand change on average annual bills:									$78.22
2) Small Volume Interruptible: Avg. Annual Use:				**4,080 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-07-XXXX**	**Last Demand Change M-08-XXXX**	**Most Recent PGA Oct 1/09**	**Nov1/09 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	-53.34%	8.55%	3.34%	$0.1312
Demand Rate									$0.0000
Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Recovery	$9.9448	$7.2226	$4.9833	$5.0967	$5.2279	-47.43%	4.91%	2.57%	$0.1312
Avg. Annual Bill*****	$40,572.00	$29,466.19	$20,330.47	$20,793.11	$21,328.46	-47.43%	4.91%	2.57%	$535.35
Effect of proposed commodity change on average annual bills:									$535.35
Effect of proposed demand change on average annual bills:									$0.00
3) Large Volume Interruptible: Avg. Annual Use:				**19,053 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-07-XXXX**	**Last Demand Change M-08-XXXX**	**Most Recent PGA Oct 1/09**	**Nov1/09 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	-53.34%	8.55%	3.34%	$0.1312
Demand Rate									$0.0000
Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Recovery	$9.0606	$6.3384	$4.0991	$4.2534	$4.3846	-51.61%	6.97%	3.09%	$0.1312
Avg. Annual Bill*****	$172,633.79	$120,767.06	$78,101.14	$81,041.05	$83,541.25	-51.61%	6.97%	3.09%	$2,500.20
Effect of proposed commodity change on average annual bills:									$2,500.20
Effect of proposed demand change on average annual bills:									$0.00
4) Small Volume Firm: Avg. Annual Use:				**4,080 Mcf**					
Avg. Annual CD Volumes:				**25 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-07-XXXX**	**Last Demand Change M-08-XXXX**	**Most Recent PGA Oct 1/09**	**Nov1/09 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	-53.34%	8.55%	3.34%	$0.1312
Demand Rate	$13.4177	$12.0195	$10.3925	$9.3592	$10.7565	-19.83%	3.50%	14.93%	$1.3973
Comm. Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$2.0724	$2.0724	$2.0724	$1.8000	-13.14%	-13.14%	-13.14%	($0.2724)
Total Commodity Cost	$9.9448	$7.2226	$4.9833	$5.0967	$5.2279	-47.43%	4.91%	2.57%	$0.1312
Total Demand Cost	$15.4901	$14.0919	$12.4649	$11.4316	$12.5565	-18.94%	0.73%	9.84%	$1.1249
Avg. Annual Bill*****	$40,959.25	$29,818.48	$20,642.09	$21,078.90	$21,642.37	-47.16%	4.85%	2.67%	$563.47
Effect of proposed commodity change on average annual bills:									$535.35
Effect of proposed demand change on average annual bills:									$34.93
5) Large Volume Firm: Avg. Annual Use:				**14,841 Mcf**					
Avg. Annual CD Units:				**75 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-07-XXXX**	**Last Demand Change M-08-XXXX**	**Most Recent PGA Oct 1/09**	**Nov1/09 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.0598	-53.34%	8.55%	3.34%	$0.1312
Demand Rate	$13.4177	$12.0195	$10.3925	$9.3592	$10.7565	-19.83%	3.50%	14.93%	$1.3973
Comm. Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
LV Dem. Margin	$0.1658	$1.6579	$1.6579	$1.6579	$1.4000	744.39%	-15.56%	-15.56%	($0.2579)
Total Commodity Cost	$9.0606	$6.3384	$4.0991	$4.2534	$4.3846	-51.61%	6.97%	3.09%	$0.1312
Total Demand Cost	$13.5835	$13.6774	$12.0504	$11.0171	$12.1565	-10.51%	0.88%	10.34%	$1.1394
Avg. Annual Bill*****	$135,487.13	$95,094.00	$61,738.52	$63,950.99	$65,983.91	-51.30%	6.88%	3.18%	$2,032.92

Attachment 11

MINNESOTA ENERGY RESOURCES - PNG

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

1) General Service: Avg. Annual Use:				**125 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case^^**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	-51.50%	12.84%	7.42%	$0.2915
Demand Rate	$1.1197	$1.0903	$1.0883	$1.0362	$1.4860	32.71%	36.54%	43.40%	$0.4498
Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Recovery	$11.4474	$8.6958	$6.4545	$6.7394	$7.4806	-34.65%	15.90%	11.00%	$0.7412
Avg. Annual Bill*	$1,429.40	$1,085.82	$805.95	$841.53	$934.08	-34.65%	15.90%	11.00%	$92.55
Effect of proposed commodity change on average annual bills:									$36.40
Effect of proposed demand change on average annual bills:									$56.16

2) Small Volume Interruptible: Avg. Annual Use:				**4,080 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	-51.50%	12.84%	7.42%	$0.2915
Demand Rate									
Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Recovery	$9.9448	$7.2226	$4.9833	$5.0967	$5.3882	-45.82%	8.12%	5.72%	$0.2915
Avg. Annual Bill*	$40,572.00	$29,466.19	$20,330.47	$20,793.11	$21,982.23	-45.82%	8.12%	5.72%	$1,189.12
Effect of proposed commodity change on average annual bills:									$1,189.12
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use:				**19,053 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	-51.50%	12.84%	7.42%	$0.2915
Demand Rate									
Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Recovery	$9.0606	$6.3384	$4.0991	$4.2534	$4.5449	-49.84%	10.87%	6.85%	$0.2915
Avg. Annual Bill*	$172,633.79	$120,767.06	$78,101.14	$81,041.05	$86,594.52	-49.84%	10.87%	6.85%	$5,553.47
Effect of proposed commodity change on average annual bills:									$5,553.47
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use:				**4,080 Mcf**					
Avg. Annual CD Volumes:				**25 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	-51.50%	12.84%	7.42%	$0.2915
Demand Rate	$13.4177	$12.0195	$10.3925	$9.3592	$15.8792	18.35%	52.79%	69.66%	$6.5200
Comm. Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$2.0724	$2.0724	$2.0724	$1.8000	-13.14%	-13.14%	-13.14%	($0.2724)
Total Commodity Cost	$9.9448	$7.2226	$4.9833	$5.0967	$5.3882	-45.82%	8.12%	5.72%	$0.2915
Total Demand Cost	$15.4901	$14.0919	$12.4649	$11.4316	$17.6792	14.13%	41.83%	54.65%	$6.2476
Avg. Annual Bill*	$40,959.25	$29,818.48	$20,642.09	$21,078.90	$22,424.21	-45.25%	8.63%	6.38%	$1,345.31
Effect of proposed commodity change on average annual bills:									$1,189.12
Effect of proposed demand change on average annual bills:									$163.00

5) Large Volume Firm: Avg. Annual Use:				**14,841 Mcf**					
Avg. Annual CD Units:				**75 Mcf**					
Recovery	**Base Cost of Gas Change G011/MR08-836^**	**Demand Change M-08-XXXX**	**Last Demand Change M-09-XXXX**	**Most Recent PGA Oct 1/10**	**Nov1/10 PGA w/ Proposed Demand Changes****	**% Change From Last Rate Case**	**% Change From Last Demand Filing**	**% Change From Last PGA**	**$ Change From Last PGA**
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9286	$4.2201	-51.50%	12.84%	7.42%	$0.2915
Demand Rate	$13.4177	$12.0195	$10.3925	$9.3592	$15.8792	18.35%	52.79%	69.66%	$6.5200
Comm. Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
LV Dem. Margin	$0.1658	$1.6579	$1.6579	$1.6579	$1.4000	744.39%	-15.56%	-15.56%	($0.2579)
Total Commodity Cost	$9.0606	$6.3384	$4.0991	$4.2534	$4.5449	-49.84%	10.87%	6.85%	$0.2915
Total Demand Cost	$13.5835	$13.6774	$12.0504	$11.0171	$17.2792	27.21%	43.39%	56.84%	$6.2621
Avg. Annual Bill*	$135,487.13	$95,094.00	$61,738.52	$63,950.99	$68,746.37	-49.26%	11.35%	7.50%	$4,795.38
Effect of proposed commodity change on average annual bills:									$4,325.72
Effect of proposed demand change on average annual bills:									$489.00

***** 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	$0.2915	7.42%	29.15%	$0.4498	43.40%	0.7412		11.00%
Sm Vol Inter. Service	$0.2915	7.42%	29.15%	$0.0000	0.00%	0.2915		5.72%
Lrg Vol Inter. Service	$0.2915	7.42%	29.15%	$0.0000	0.00%	0.2915		6.85%
Sm Vol Joint Service	$0.2915	7.42%	29.15%	$6.5200	69.66%	0.2915	***	5.72%
Lrg Vol Joint Service	$0.2915	7.42%	29.15%	$6.5200	69.66%	0.2915	***	6.85%

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

Attachment 12

MINNESOTA ENERGY RESOURCES - PNG

Change in Costs due to November 1, 2010 Change in Entitlement Levels and Related Demand Costs

NNG

	Contract	Oct-10 PGA	Nov-10 Entitlement	Entitlement Change	Months	Oct-10 Rate/MCF	Oct-10 Total Cost	Entitlement Total Cost	Entitlement Change
TF-12-B (Max Rate)	112495	30,021	29,675	(346)	12	$ 7.5776	$2,729,840	$2,698,383	($31,456)
TF-12-B (Discount)	112495	5,200	5,200	0	12	$ 6.4818	$404,591	$404,464	($127)
TF-12-V (Max Rate)	112495	24,583	32,290	7,707	12	$ 9.0926	$2,682,276	$3,523,201	$840,925
TF-5 (Max Rate)	112495	29,619	28,785	(834)	5	$ 15.1530	$2,244,084	$2,180,896	($63,188)
TF-5 (Discount)	112495	0	0	0	5	$ 7.6050	$0	$0	$0
TFX-12 (Max Rate)	112486	9,724	9,651	(73)	12	$ 9.6288	$1,123,569	$1,115,131	($8,439)
TFX-12 (Discount)	111866	414	1,144	730	12	$ 4.8640	$24,178	$66,773	$42,595
TFX-12 (Discount)	111866	9,140	7,376	(1,764)	12	$ 5.4720	$598,524	$484,338	($114,186)
TFX-12 (Discount)	111866	11,921	10,631	(1,290)	12	$ 2.2192	$317,633	$283,108	($34,525)
TFX-5 (Max Rate)	112486	48,754	51,163	2,409	5	$ 15.1530	$3,693,847	$3,876,365	$182,518
TFX-5 (Discount)	112486	0	0	0	5	$ 13.8736	$0	$0	$0
TFX-5 (Discount)	112486	1,800	1,605	(195)	5	$ 7.6050	$68,445	$61,030	($7,415)
TFX-5 (Discount)	111866	122	338	216	5	$ 4.8640	$2,969	$8,220	$5,251
TFX-5 (Discount)	111866	2,702	2,180	(522)	5	$ 5.4720	$73,724	$59,645	($14,079)
TFX-5 (Discount)	111866	22,189	19,788	(2,401)	5	$ 15.1392	$1,680,539	$1,497,872	($182,667)
TFX-5 (Discount)	112561	6,000	5,351	(649)	5	$ 4.5600	$136,800	$122,003	($14,797)
TFX-7 (Discount)	111866	0	0	0	7	$ 2.2192	$0	$0	$0
TFX Oct (Max Rate)	112486	2,000	1,784	(216)	1	$ 5.6830	$11,366	$10,138	($1,228)
TFX Apr (Max Rate)	112486	2,000	1,784	(216)	1	$ 5.6830	$11,366	$10,138	($1,228)
SMS Charge		20,577	20,226	(351)	12	$ 2.1800	$538,304	$529,112	($9,192)
LS Power		26,375	25,951	(424)	3	$ 4.3463	$343,903	$338,369	($5,534)
WINDOM		2,500	2,500	0	12	$ -	$0	$0	$0
Bison		0	44,589	44,589	10.5	$ 17.4800	$0	$8,183,865	$8,183,865
NBPL		0	44,589	44,589	10.5	$ 6.9920	$0	$3,273,546	$3,273,546
FDD: Storage Reservation		71,593	73,460	1,867	12	$ 1.7140	$1,472,516	$1,510,925	$38,410
FDD: Storage Reservation		5,035	4,949	(86)	12	$ 3.3157	$200,353	$196,913	($3,440)
FDD: Storage Cycle Volume		825,512	847,070	21,558	5	$ 0.3567	$1,472,301	$1,510,749	$38,449
FDD: Storage Cycle Volume		58,067	57,074	(993)	5	$ 0.6901	$200,359	$196,934	($3,425)
Total Demand Cost							$20,031,484	$32,142,118	$12,110,634

Costs Assigned In Commodity: Upstream	Oct-10 PGA	Nov-10 Entitlement	Entitlement Change	Months	Oct-10 Rate/MCF	Oct-10 Total Cost	Entitlement Total Cost	Entitlement Change
Great Lakes	0	0	0	12	$3.458	$0	$0	$0
			0				$0	$0
Surcharges:			0				$0	$0
			0				$0	$0
Storage			0				$0	$0
FDD Withdrawal	4,417,893	4,520,719	102,826	1	$0.0149	$65,827	$67,359	$1,532
FDD Injection	4,417,893	4,520,719	102,826	1	$0.0149	$65,827	$67,359	$1,532
							$0	$0
							$0	$0
Producer Demand Payments/Option Premium						$2,672,469	$1,876,399	($796,070)
Total Commodity Costs						$2,804,122	$2,011,117	($793,005)

Attachment 13

MINNESOTA ENERGY RESOURCES - PNG

Daily Total Throughput Data - July 1, 2009 through June 30, 2010

NNG

Base	30,580
Variable	2,337

Date	3.46% Cloquet Adjusted HDD	32.86% Minneapolis Adjusted HDD	63.68% Rochester Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/09	10	1	7	5	35,372	41,898
7/2/09	8	0	0	0	32,412	31,259
7/3/09	3	0	0	0	28,159	30,835
7/4/09	3	0	0	0	26,730	30,837
7/5/09	3	0	0	0	30,652	30,842
7/6/09	4	0	0	0	39,321	30,923
7/7/09	6	0	0	0	38,299	31,089
7/8/09	7	0	4	3	35,012	37,793
7/9/09	0	0	0	0	36,389	30,580
7/10/09	0	0	0	0	35,593	30,580
7/11/09	7	0	0	0	28,552	31,114
7/12/09	7	0	0	0	29,826	31,180
7/13/09	4	0	0	0	34,950	30,913
7/14/09	7	0	0	0	36,895	31,109
7/15/09	9	0	1	1	35,933	32,971
7/16/09	14	1	5	4	36,847	39,475
7/17/09	12	6	8	7	34,430	47,517
7/18/09	14	4	10	8	31,135	49,385
7/19/09	6	0	4	3	31,347	37,320
7/20/09	0	0	0	0	34,810	30,580
7/21/09	4	0	1	1	35,711	32,476
7/22/09	4	0	0	0	36,133	30,916
7/23/09	0	0	0	0	35,927	30,580
7/24/09	0	0	0	0	32,834	30,580
7/25/09	2	0	0	0	28,980	30,756
7/26/09	0	0	0	0	30,789	30,580
7/27/09	0	0	0	0	40,415	30,580
7/28/09	9	0	3	2	38,241	36,247
7/29/09	4	0	0	0	36,442	30,923
7/30/09	9	0	4	3	36,598	37,818
7/31/09	2	0	0	0	32,016	30,758
8/1/09	11	1	6	4	31,230	40,589
8/2/09	8	0	0	0	31,932	31,233
8/3/09	4	0	0	0	34,277	30,929
8/4/09	8	0	2	2	35,898	34,382
8/5/09	8	0	0	0	35,710	31,266
8/6/09	2	0	0	0	33,746	30,747
8/7/09	5	0	0	0	31,960	31,009
8/8/09	3	0	0	0	28,922	30,832
8/9/09	1	0	0	0	31,611	30,666
8/10/09	1	0	0	0	41,042	30,665
8/11/09	0	0	0	0	39,316	30,580
8/12/09	0	0	0	0	43,032	30,580
8/13/09	0	0	0	0	37,421	30,580
8/14/09	0	0	0	0	32,483	30,580
8/15/09	0	0	0	0	33,116	30,580
8/16/09	0	0	0	0	31,943	30,580
8/17/09	3	0	1	1	37,039	32,439
8/18/09	4	0	0	0	36,905	30,926

9/26/09	5	0	2	2	33,443	34,257
9/27/09	12	5	7	6	37,522	45,710
9/28/09	22	19	19	19	53,154	75,058
9/29/09	25	19	20	20	54,356	76,706
9/30/09	24	16	15	15	51,916	66,745
10/1/09	22	19	18	18	63,750	73,775
10/2/09	25	20	19	19	62,626	75,786
10/3/09	21	18	20	19	61,162	75,860
10/4/09	22	19	22	21	65,007	80,351
10/5/09	20	19	20	20	69,988	76,932
10/6/09	28	24	25	25	79,915	88,104
10/7/09	23	14	13	14	69,352	63,074
10/8/09	31	27	26	27	86,588	92,906
10/9/09	35	31	31	31	90,493	102,890
10/10/09	42	37	37	37	100,141	116,633
10/11/09	34	32	32	32	92,381	105,525
10/12/09	40	35	36	36	114,505	113,850
10/13/09	35	31	33	32	106,438	106,300
10/14/09	33	29	29	29	101,109	99,172
10/15/09	32	30	33	32	93,467	105,293
10/16/09	33	27	27	27	82,952	94,605
10/17/09	29	24	26	26	76,289	90,191
10/18/09	21	14	19	17	62,217	70,873
10/19/09	23	13	10	11	63,591	56,698
10/20/09	26	17	15	16	70,035	68,076
10/21/09	35	26	24	25	86,584	88,159
10/22/09	34	29	29	29	95,420	99,404
10/23/09	35	32	34	33	97,523	108,151
10/24/09	28	24	24	24	67,698	86,605
10/25/09	29	21	21	22	75,527	80,900
10/26/09	32	24	29	27	96,051	94,233
10/27/09	23	20	23	22	89,817	82,187
10/28/09	26	19	18	18	87,402	73,604
10/29/09	20	12	9	11	75,464	55,277
10/30/09	25	20	22	21	83,876	80,313
10/31/09	34	28	30	29	98,605	98,667
11/1/09	32	19	19	19	83,348	76,138
11/2/09	37	29	30	30	114,909	100,570
11/3/09	32	26	28	27	114,375	94,202
11/4/09	34	30	31	31	119,997	102,193
11/5/09	31	23	20	22	96,093	80,968
11/6/09	20	12	13	13	66,231	60,585
11/7/09	21	13	11	12	70,835	58,208
11/8/09	27	15	13	14	72,341	64,248
11/9/09	27	20	18	19	93,990	74,316
11/10/09	20	15	19	18	95,805	72,628
11/11/09	20	17	19	19	97,497	73,909
11/12/09	20	17	22	20	96,637	77,343
11/13/09	22	18	18	18	88,544	72,632
11/14/09	36	29	31	30	109,937	101,304
11/15/09	34	27	30	29	115,641	98,201
11/16/09	33	28	27	28	123,697	95,158
11/17/09	32	28	26	27	123,418	93,632
11/18/09	29	23	22	23	105,959	83,343
11/19/09	25	22	22	22	104,578	82,952
11/20/09	32	24	24	24	105,888	86,538
11/21/09	30	25	27	26	95,526	92,434
11/22/09	20	13	13	13	81,709	62,091
11/23/09	23	19	18	18	92,649	73,090
11/24/09	27	24	22	23	97,490	83,932
11/25/09	39	33	33	33	113,145	107,856
11/26/09	43	38	41	40	116.671	123.969

1/3/10	82	70	75	73	196,587	202,116
1/4/10	75	71	79	76	202,423	208,472
1/5/10	68	64	73	70	190,900	194,723
1/6/10	65	60	63	62	173,170	175,494
1/7/10	75	70	74	73	184,301	200,379
1/8/10	74	72	80	77	186,939	210,559
1/9/10	69	72	78	76	182,132	207,765
1/10/10	61	57	63	61	158,817	173,601
1/11/10	56	56	60	58	161,541	167,031
1/12/10	55	55	60	58	151,445	166,086
1/13/10	48	46	47	47	128,045	139,445
1/14/10	52	44	46	46	127,180	137,255
1/15/10	54	45	48	47	126,702	140,470
1/16/10	41	41	48	46	113,720	137,494
1/17/10	38	41	49	46	121,130	137,561
1/18/10	44	43	50	48	143,985	142,372
1/19/10	51	48	51	50	144,758	147,765
1/20/10	50	45	47	47	129,622	139,477
1/21/10	45	40	40	40	118,984	124,900
1/22/10	40	38	41	40	111,667	123,926
1/23/10	36	34	35	35	99,319	111,780
1/24/10	43	40	43	42	110,722	128,767
1/25/10	62	58	60	59	154,749	169,099
1/26/10	70	64	70	68	177,600	189,240
1/27/10	78	68	73	71	183,473	197,418
1/28/10	77	67	72	70	189,826	194,640
1/29/10	72	64	66	66	173,394	184,001
1/30/10	70	57	62	60	153,223	171,807
1/31/10	71	57	60	59	158,350	169,005
2/1/10	64	56	54	55	154,645	159,118
2/2/10	63	56	61	59	156,112	169,628
2/3/10	58	55	59	57	142,206	164,806
2/4/10	45	42	42	42	120,720	128,433
2/5/10	47	40	44	43	112,560	130,359
2/6/10	48	48	49	49	120,113	144,374
2/7/10	50	50	53	52	126,622	152,340
2/8/10	52	47	49	49	138,800	144,196
2/9/10	60	55	61	59	145,270	169,159
2/10/10	60	55	66	62	157,460	176,283
2/11/10	57	51	59	56	146,665	161,352
2/12/10	57	50	57	55	138,047	159,044
2/13/10	53	51	61	58	139,169	165,558
2/14/10	58	53	60	58	134,862	165,571
2/15/10	52	46	50	49	134,116	145,233
2/16/10	48	44	49	48	126,246	141,621
2/17/10	45	44	56	52	129,164	151,453
2/18/10	45	45	55	51	135,113	149,629
2/19/10	44	46	49	48	119,796	142,165
2/20/10	45	42	50	47	117,403	141,516
2/21/10	46	42	53	49	123,984	146,039
2/22/10	49	48	56	53	133,847	154,094
2/23/10	66	60	67	64	160,942	181,181
2/24/10	62	55	63	61	162,707	172,024
2/25/10	60	51	55	53	147,851	155,494
2/26/10	47	46	54	51	130,694	149,742
2/27/10	41	40	48	45	112,978	136,180
2/28/10	46	38	44	42	109,006	128,194
3/1/10	43	37	46	43	114,458	130,926
3/2/10	38	34	43	40	109,799	123,002
3/3/10	37	35	43	40	110,146	124,167
3/4/10	37	36	44	41	105,348	125,998
3/5/10	33	34	42	39	97.568	121.413

4/12/10	21	9	11	11	45,745	55,998
4/13/10	26	7	5	6	38,388	45,124
4/14/10	17	0	0	1	35,028	31,926
4/15/10	12	7	7	7	38,144	47,175
4/16/10	23	17	20	19	45,616	74,535
4/17/10	22	14	16	15	42,407	66,106
4/18/10	22	9	12	11	40,159	56,998
4/19/10	21	7	13	11	41,326	56,712
4/20/10	16	7	7	8	40,604	48,369
4/21/10	33	17	15	16	46,244	69,119
4/22/10	22	10	9	10	41,180	53,120
4/23/10	8	7	8	8	36,693	48,811
4/24/10	22	12	10	11	35,553	57,357
4/25/10	25	13	16	16	46,681	67,133
4/26/10	24	15	18	17	52,021	70,412
4/27/10	26	15	21	19	59,510	75,413
4/28/10	19	5	5	5	49,055	42,559
4/29/10	22	0	0	1	40,877	32,359
4/30/10	18	7	8	8	35,187	49,190
5/1/10	19	10	13	12	35,071	58,986
5/2/10	18	10	11	11	39,137	56,735
5/3/10	27	17	16	16	49,831	69,017
5/4/10	21	2	1	2	43,472	35,746
5/5/10	26	20	18	19	52,112	74,830
5/6/10	23	17	16	17	50,346	69,253
5/7/10	36	27	27	27	65,251	94,296
5/8/10	30	24	27	26	60,141	91,393
5/9/10	22	14	17	16	47,970	68,151
5/10/10	20	19	21	20	59,900	77,032
5/11/10	26	23	24	24	70,306	86,288
5/12/10	20	19	21	20	63,849	77,108
5/13/10	25	17	19	18	58,220	72,996
5/14/10	20	6	8	8	37,908	48,598
5/15/10	12	1	7	5	30,580	43,403
5/16/10	6	1	5	4	32,436	40,000
5/17/10	10	0	3	2	35,565	36,109
5/18/10	9	2	5	4	37,258	40,733
5/19/10	5	0	0	0	37,534	31,005
5/20/10	6	0	0	0	36,007	31,094
5/21/10	11	4	6	6	32,741	44,368
5/22/10	6	0	0	0	29,178	31,104
5/23/10	0	0	0	0	31,178	30,580
5/24/10	5	0	0	0	41,115	31,009
5/25/10	0	0	0	0	37,201	30,580
5/26/10	6	0	0	0	36,531	31,094
5/27/10	2	0	0	0	35,112	30,745
5/28/10	6	0	0	0	29,639	31,089
5/29/10	2	0	0	0	25,553	30,751
5/30/10	7	0	0	0	25,339	31,180
5/31/10	2	0	0	0	30,154	30,751
6/1/10	8	0	0	0	35,196	31,191
6/2/10	13	2	5	5	36,636	41,137
6/3/10	3	0	0	0	35,540	30,832
6/4/10	7	0	0	0	31,659	31,163
6/5/10	7	2	0	1	28,701	32,787
6/6/10	19	0	3	3	30,513	36,856
6/7/10	5	0	0	0	34,232	31,005
6/8/10	13	0	1	1	38,326	33,270
6/9/10	11	0	1	1	31,920	33,151
6/10/10	13	2	2	3	38,004	36,707
6/11/10	13	0	0	0	35,395	31,638
6/12/10	10	6	3	5	31.476	41.111

MINNESOTA ENERGY RESOURCES - PNG

Customer Counts by PGAC Class - July 1, 2009 through June 30, 2010

Rate Class	Tariff Rate Designation	Jul-09 Average Customers	Aug-09 Average Customers	Sep-09 Average Customers	Oct-09 Average Customers	Nov-09 Average Customers	Dec-09 Average Customers	Jan-10 Average Customers	Feb-10 Average Customers	Mar-10 Average Customers	Apr-10 Average Customers	May-10 Average Customers	Jun-10 Average Customers
Residential w/ Heat	MN001/007/008	141,945	141,177	141,270	141,649	142,733	143,117	143,734	144,154	143,668	143,852	143,785	143,669
Residential w/o Heat	MN002/009/010	952	934	937	943	951	963	955	969	962	962	970	952
Commercial-SV	MN050/053/054/ 070/076/078	5,969	5,905	5,900	5,896	5,964	6,023	6,066	6,060	6,050	6,059	6,465	6,419
Commercial-LV	MN056/060/063/ 064/065/071/077	7,744	7,721	7,691	7,702	7,779	7,751	7,900	7,855	7,835	7,863	7,374	7,340
SV-Joint	MN104	0	0	0	0	3	1	1	1	1	1	1	1
SV-Interruptible	MN125/128/135	341	338	338	341	338	349	341	337	342	340	270	332
LV-Interruptible	MN200/201/207	40	41	39	39	41	39	39	37	38	38	36	36
LV-Interruptible-ML	MN220/221	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN590	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN509/514/589	3	3	4	3	4	7	8	7	7	7	6	5
Transport	MN518	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN502/507/82L	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN500/574/81L	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN501/506/522/ 523/80L	15	24	15	14	15	15	15	18	16	16	18	18
Transport	MN/504/505/539	12	13	13	13	13	13	25	12	17	18	13	13
Transport	MN/512	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/515	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/517	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/519	0	0	0	0	0	0	0	0	0	0	0	0
Transport	MN/535	0	0	0	0	0	0	0	0	0	0	0	0
Total		157,021	156,156	156,207	156,600	157,841	158,278	159,084	159,450	158,936	159,156	158,938	158,785

MINNESOTA ENERGY RESOURCES - PNG

Projected Fixed Cost - November 2009 through March 2010

Futures Contracts WACOG

NNG-PNG
Fixed Price

Nov-10 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/18/10	103,846	$ 4.9860	$ 517,777	$ 3.4398	$ 357,209	$ 160,568
06/18/10	13,846	$ 5.4020	$ 74,797	$ 3.4398	$ 47,628	$ 27,169
06/18/10	96,923	$ 5.4040	$ 523,772	$ 3.4398	$ 333,395	$ 190,377
07/08/10	96,923	$ 4.8260	$ 467,751	$ 3.4398	$ 333,395	$ 134,356
08/05/10	83,077	$ 4.8000	$ 398,769	$ 3.4398	$ 285,767	$ 113,002
09/27/10	76,154	$ 3.8710	$ 294,792	$ 3.4398	$ 261,953	$ 32,838
10/05/10	20,769	$ 3.7240	$ 77,345	$ 3.4398	$ 71,442	$ 5,903
10/05/10	48,462	$ 3.7250	$ 180,519	$ 3.4398	$ 166,698	$ 13,822
Total	540,000		$ 2,535,522		$ 1,857,487	$ 678,035
WACOG			$ 4.6954		$ 3.4398	$ 1.2556

Dec-10 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/20/10	5,750	$ 5.1600	$ 29,670	$ 3.9575	$ 22,756	$ 6,914
05/20/10	5,750	$ 5.1610	$ 29,676	$ 3.9575	$ 22,756	$ 6,920
05/20/10	11,500	$ 5.1620	$ 59,363	$ 3.9575	$ 45,511	$ 13,852
05/20/10	5,750	$ 5.1630	$ 29,687	$ 3.9575	$ 22,756	$ 6,932
05/20/10	23,000	$ 5.1640	$ 118,772	$ 3.9575	$ 91,023	$ 27,749
06/29/10	63,250	$ 5.2840	$ 334,213	$ 3.9575	$ 250,313	$ 83,900
07/29/10	40,250	$ 5.1650	$ 207,891	$ 3.9575	$ 159,290	$ 48,601
08/06/10	28,750	$ 4.9940	$ 143,578	$ 3.9575	$ 113,779	$ 29,799
09/14/10	23,000	$ 4.3490	$ 100,027	$ 3.9575	$ 91,023	$ 9,004
10/07/10	23,000	$ 4.0600	$ 93,380	$ 3.9575	$ 91,023	$ 2,357
	230,000		$ 1,146,257		$ 910,230	$ 236,027
			$ 4.9837		$ 3.9575	$ 1.0262

Jan-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/21/10	63,768	$ 5.3350	$ 340,203	$ 4.1429	$ 264,185	$ 76,018
05/21/10	6,377	$ 5.3370	$ 34,033	$ 4.1429	$ 26,418	$ 7,615
06/28/10	6,377	$ 5.6450	$ 35,997	$ 4.1429	$ 26,418	$ 9,579
06/28/10	25,507	$ 5.6460	$ 144,014	$ 4.1429	$ 105,674	$ 38,340
06/28/10	63,768	$ 5.6490	$ 360,226	$ 4.1429	$ 264,185	$ 96,041
07/29/10	38,261	$ 5.2910	$ 202,438	$ 4.1429	$ 158,511	$ 43,927
07/29/10	6,377	$ 5.2920	$ 33,746	$ 4.1429	$ 26,418	$ 7,328
07/29/10	6,377	$ 5.2930	$ 33,752	$ 4.1429	$ 26,418	$ 7,334
07/29/10	31,884	$ 5.2940	$ 168,794	$ 4.1429	$ 132,092	$ 36,702
08/10/10	19,130	$ 4.9870	$ 95,403	$ 4.1429	$ 79,255	$ 16,148
08/10/10	6,377	$ 4.9880	$ 31,808	$ 4.1429	$ 26,418	$ 5,389
08/10/10	12,754	$ 4.9890	$ 63,628	$ 4.1429	$ 52,837	$ 10,791
08/10/10	31,884	$ 4.9900	$ 159,101	$ 4.1429	$ 132,092	$ 27,009
09/27/10	51,014	$ 4.3120	$ 219,974	$ 4.1429	$ 211,348	$ 8,627
09/27/10	12,754	$ 4.3130	$ 55,006	$ 4.1429	$ 52,837	$ 2,169
10/07/10	25,507	$ 4.2450	$ 108,278	$ 4.1429	$ 105,674	$ 2,604
10/07/10	31,884	$ 4.2460	$ 135,380	$ 4.1429	$ 132,092	$ 3,287
	440,000		$ 2,221,783		$ 1,822,875	$ 398,908
			$ 5.0495		$ 4.1429	$ 0.9066

Feb-10 (28)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/24/10	11,250	$ 5.2550	$ 59,119	$ 4.1796	$ 47,020	$ 12,098
05/24/10	5,625	$ 5.2560	$ 29,565	$ 4.1796	$ 23,510	$ 6,055
05/24/10	22,500	$ 5.2570	$ 118,282	$ 4.1796	$ 94,041	$ 24,242
06/10/10	50,625	$ 5.5990	$ 283,449	$ 4.1796	$ 211,591	$ 71,858
07/29/10	33,750	$ 5.2390	$ 176,816	$ 4.1796	$ 141,061	$ 35,755
08/09/10	22,500	$ 4.9990	$ 112,477	$ 4.1796	$ 94,041	$ 18,437
09/29/10	16,875	$ 4.3150	$ 72,816	$ 4.1796	$ 70,530	$ 2,285
10/07/10	16,875	$ 4.2630	$ 71,938	$ 4.1796	$ 70,530	$ 1,408
Total	180,000		$ 924,463		$ 752,324	$ 172,139
WACOG			$ 5.1359		$ 4.1796	$ 0.9563

Mar-11 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/14/10	89,894	$ 5.4850	$ 493,066	$ 4.0526	$ 364,301	$ 128,765
05/14/10	20,745	$ 5.4880	$ 113,847	$ 4.0526	$ 84,069	$ 29,777
06/21/10	131,383	$ 5.5150	$ 724,577	$ 4.0526	$ 532,440	$ 192,137
07/29/10	55,319	$ 5.1410	$ 284,396	$ 4.0526	$ 224,185	$ 60,210
07/29/10	69,149	$ 5.1420	$ 355,564	$ 4.0526	$ 280,232	$ 75,332
08/19/10	13,830	$ 4.7080	$ 65,111	$ 4.0526	$ 56,046	$ 9,064
08/19/10	13,830	$ 4.7090	$ 65,124	$ 4.0526	$ 56,046	$ 9,078
08/19/10	76,064	$ 4.7100	$ 358,261	$ 4.0526	$ 308,255	$ 50,006
09/27/10	89,894	$ 4.2640	$ 383,306	$ 4.0526	$ 364,301	$ 19,005
10/07/10	76,064	$ 4.2350	$ 322,130	$ 4.0526	$ 308,255	$ 13,876
10/07/10	13,830	$ 4.2390	$ 58,624	$ 4.0526	$ 56,046	$ 2,578
	650,000		$ 3,224,007		$ 2,634,177	$ 589,830
			$ 4.9600		$ 4.0526	$ 0.9074

Total

	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	274,508	$ 5.2452	$ 1,439,835	$ 3.8450	$ 1,055,471	$ 384,364
	52,343	$ 5.3860	$ 281,918	$ 3.9047	$ 204,382	$ 77,536
	268,683	$ 5.4413	$ 1,461,992	$ 3.8402	$ 1,031,806	$ 430,186
	234,124	$ 5.1652	$ 1,209,297	$ 3.8339	$ 897,601	$ 311,696
	272,744	$ 5.1702	$ 1,410,147	$ 3.8947	$ 1,062,267	$ 347,880
	213,995	$ 4.7152	$ 1,009,031	$ 3.8359	$ 820,864	$ 188,167
	98,101	$ 4.6577	$ 456,922	$ 3.9116	$ 383,727	$ 73,195
	176,527	$ 4.4642	$ 788,048	$ 3.8843	$ 685,680	$ 102,368
	144,778	$ 4.5043	$ 652,128	$ 4.0574	$ 587,417	$ 64,711
	118,194	$ 4.3227	$ 510,914	$ 4.0487	$ 478,533	$ 32,381
	20,207	$ 4.4754	$ 90,432	$ 4.0811	$ 82,465	$ 7,967
	12,754	$ 4.9890	$ 63,628	$ 4.1429	$ 52,837	$ 10,791
	31,884	$ 4.9900	$ 159,101	$ 4.1429	$ 132,092	$ 27,009
	51,014	$ 4.3120	$ 219,974	$ 4.1429	$ 211,348	$ 8,627
	12,754	$ 4.3130	$ 55,006	$ 4.1429	$ 52,837	$ 2,169
	25,507	$ 4.2450	$ 108,278	$ 4.1429	$ 105,674	$ 2,604
	31,884	$ 4.2460	$ 135,380	$ 4.1429	$ 132,092	$ 3,287
	2,040,000		$ 10,052,032		$ 7,977,093	$ 2,071,651
			$ 4.9275		$ 3.9103	$ 1.0155

MINNESOTA ENERGY RESOURCES - PNG

Projected Storage/Exchange Volumes Cost - November 2010 through March 2011

Month/ Year	K#118657 NNG Storage	Storage K#121292 LS Power	Total NNG Storage	WACOG Projected K#118657 NNG WACOG	Projected K#121292 NNG WACOG	K#118657 NNG Storage Cost	K#121292 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-10	455,259	39,000	494,259	$ 4.0923	$ 4.0923	$ 1,863,052	$ 159,599	$ 2,022,651	94,773	$ 3.7863	$ 358,837
Dec-10	1,143,984	98,000	1,241,984	$ 4.0923	$ 4.0923	$ 4,681,515	$ 401,044	$ 5,082,559	260,095	$ 3.7863	$ 984,793
Jan-11	1,143,984	98,000	1,241,984	$ 4.0923	$ 4.0923	$ 4,681,515	$ 401,044	$ 5,082,559	260,095	$ 3.7863	$ 984,793
Feb-11	1,143,984	98,000	1,241,984	$ 4.0923	$ 4.0923	$ 4,681,515	$ 401,044	$ 5,082,559	234,925	$ 3.7863	$ 889,492
Mar-11	455,259	39,000	494,259	$ 4.0923	$ 4.0923	$ 1,863,052	$ 159,599	$ 2,022,651	97,932	$ 3.7863	$ 370,798
Total	4,342,470	372,000	4,714,470	$ 4.0923	$ 4.0923	$ 17,770,648	$ 1,522,332	$ 19,292,980	947,820	$ 3.7863	$ 3,588,712
								$ 4.0923			$ 3.7863

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	AECO Storage LDS + Basis	AECO Storage LDS + Cost		Total AECO Storage Volumes	Total AECO Storage WACOG	Total AECO Storage Cost	Total AECO Storage Market WACOG	Total AECO Storage Market Cost
Nov-10	494,259	$ 3.6890	$ 1,823,321	94,773	$ 3.7065	$ 351,276		94,773	$ 3.7863	$ 358,837	$ 3.7065	$ 351,276
Dec-10	1,241,984	$ 4.0684	$ 5,052,852	260,095	$ 4.1445	$ 1,077,964		260,095	$ 3.7863	$ 984,793	$ 4.1445	$ 1,077,964
Jan-11	1,241,984	$ 4.3351	$ 5,384,181	260,095	$ 4.2080	$ 1,094,480		260,095	$ 3.7863	$ 984,793	$ 4.2080	$ 1,094,480
Feb-11	1,241,984	$ 4.3571	$ 5,411,451	234,925	$ 4.2170	$ 990,679		234,925	$ 3.7863	$ 889,492	$ 4.2170	$ 990,679
Mar-11	494,259	$ 4.2157	$ 2,083,645	97,932	$ 4.1795	$ 409,307		97,932	$ 3.7863	$ 370,798	$ 4.1795	$ 409,307
Total	4,714,470	$ 4.1904	$ 19,755,450	947,820	$ 4.1397	$ 3,923,705		947,820	$ 3.7863	$ 3,588,712	$ 4.1397	$ 3,923,705

Max NNG Storage (Storage plan withdrawals through Apr 1(	4,714,470	5,069,321	10/31/09 Storage Balance - NNG (estimate)	5,069,321	100.00%	4,714,470
Max Nexen Emerson	947,820		10/31/09 PSO Balance - Nexen Emersor	947,820		

Month/ Year	K#118657 NNG Storage	Storage K#121292 LS Power	Total NNG Storage	NNG PNG Volumes	NNG NMU Volumes	NNG Total Volumes	Projected K#118657 NNG WACOG	Projected K#121292 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-10	455,259	39,000	494,259	429,894	44,865	474,759	$ 4.0923	$ 4.0923	$ 1,759,251	$ 183,601	$ 1,942,852	$ 3.6890	$ 1,585,879	$ 165,507	$ 1,751,386
Dec-10	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.0684	$ 4,394,846	$ 458,656	$ 4,853,502
Jan-11	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.3351	$ 4,683,028	$ 488,731	$ 5,171,759
Feb-11	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.3571	$ 4,706,747	$ 491,207	$ 5,197,953
Mar-11	455,259	39,000	494,259	429,894	44,865	474,759	$ 4.0923	$ 4.0923	$ 1,759,251	$ 183,601	$ 1,942,852	$ 4.2157	$ 1,812,301	$ 189,137	$ 2,001,438
Total	4,342,470	372,000	4,714,470	4,100,529	427,941	4,528,470	$ 4.0923	$ 4.0923	$ 16,780,555	$ 1,751,259	$ 18,531,814	$ 4.1904	$ 17,182,800	$ 1,793,238	$ 18,976,038
									$ 4.0923	$ 4.0923	$ 3.9308		$ 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 Nexen Cost
Nov-10	94,773	15,429	27,626	12,846	21,064	17,808	94,773	$ 3.7863	$ 58,420	$ 104,600	$ 48,637	$ 79,753	$ 67,427	$ 358,837
Dec-10	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 3.7863	$ 160,327	$ 287,063	$ 133,481	$ 218,875	$ 185,048	$ 984,793
Jan-11	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 3.7863	$ 160,327	$ 287,063	$ 133,481	$ 218,875	$ 185,048	$ 984,793
Feb-11	234,925	38,246	68,480	31,842	52,213	44,144	234,925	$ 3.7863	$ 144,811	$ 259,283	$ 120,563	$ 197,694	$ 167,140	$ 889,492
Mar-11	97,932	15,944	28,547	13,274	21,766	18,402	97,932	$ 3.7863	$ 60,367	$ 108,086	$ 50,259	$ 82,411	$ 69,675	$ 370,798
Total	947,820	154,307	276,286	128,469	210,657	178,101	947,820	$ 3.7863	$ 584,251	$ 1,046,095	$ 486,421	$ 797,607	$ 674,339	$ 3,588,712
		16.28%	29.15%	13.55%	22.23%	18.79%	100.00%		$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total Nexen Volumes	Projected AECO Index Price	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total Nexen Cost
Nov-10	94,773	15,429	27,626	12,846	21,064	17,808	94,773	$ 3.7065	$ 57,189	$ 102,396	$ 47,613	$ 78,073	$ 66,007	$ 351,276
Dec-10	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 4.1445	$ 175,495	$ 314,222	$ 146,109	$ 239,582	$ 202,555	$ 1,077,964
Jan-11	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 4.2080	$ 178,184	$ 319,036	$ 148,348	$ 243,253	$ 205,659	$ 1,094,480
Feb-11	234,925	38,246	68,480	31,842	52,213	44,144	234,925	$ 4.2170	$ 161,285	$ 288,779	$ 134,278	$ 220,183	$ 186,154	$ 990,679
Mar-11	97,932	15,944	28,547	13,274	21,766	18,402	97,932	$ 4.1795	$ 66,636	$ 119,311	$ 55,478	$ 90,970	$ 76,911	$ 409,307
Total	947,820	154,307	276,286	128,469	210,657	178,101	947,820	$ 4.1397	638,788	1,143,744	531,826	872,061	737,286	3,923,705
		16.28%	29.15%	13.55%	22.23%	18.79%	100.00%		$ 4.1397	$ 4.1397	$ 4.1397	$ 4.1397	$ 4.1397	$ 4.1397

MINNESOTA ENERGY RESOURCES - PNG

Projected Call Option Costs - November 2010 through March 2011

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-10

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/25/10		13	130,000	$ 5.0000	$ 650,000	$ 3.6290	$ 521,170	$ 3.6290	$ 521,170	$ -	$ 0.4350	$ 56,550	$ 577,720
2	06/29/10		15	150,000	$ 5.0000	$ 750,000	$ 3.6290	$ 601,350	$ 3.6290	$ 601,350	$ -	$ 0.5550	$ 83,250	$ 684,600
3	07/02/10		15	150,000	$ 5.0000	$ 750,000	$ 3.6290	$ 601,350	$ 3.6290	$ 601,350	$ -	$ 0.5600	$ 84,000	$ 685,350
4	08/19/10		20	200,000	$ 4.5000	$ 900,000	$ 3.6290	$ 801,800	$ 3.6290	$ 801,800	$ -	$ 0.2800	$ 56,000	$ 857,800
5	09/29/10		20	200,000	$ 4.0000	$ 800,000	$ 3.6290	$ 800,000	$ 3.6290	$ 801,800	$ (1,800)	$ 0.1540	$ 30,800	$ 830,800
6	10/05/10		19	190,000	$ 4.0000	$ 760,000	$ 3.6290	$ 760,000	$ 3.6290	$ 761,710	$ (1,710)	$ 0.0540	$ 10,260	$ 770,260
7														
8														
9														
10														
Total			102	1,020,000		$ 4,610,000		$ 4,085,670		$ 4,089,180	$ (3,510)		$ 320,860	$ 4,406,530
						$ 4.5196		$ 4.0056		$ 4.0090	$ (0.0034)		$ 0.3146	$ 4.3201
NNG-PNG	74	72.55%	74	740,010	$ 4.5196	$ 3,344,555	$ 4.0056	$ 2,964,154	$ 4.0090	$ 2,966,700	$ (2,547)	$ 0.3146	$ 232,784	$ 3,196,938
NNG-NMU	9	8.82%	9	89,964	$ 4.5196	$ 406,602	$ 4.0056	$ 360,356	$ 4.0090	$ 360,666	$ (310)	$ 0.3146	$ 28,300	$ 388,656
GLGT-PNG	3	2.94%	3	29,988	$ 4.5196	$ 135,534	$ 4.0056	$ 120,119	$ 4.0090	$ 120,222	$ (103)	$ 0.3146	$ 9,433	$ 129,552
GLGT-NMU	5	4.90%	5	49,980	$ 4.5196	$ 225,890	$ 4.0056	$ 200,198	$ 4.0090	$ 200,370	$ (172)	$ 0.3146	$ 15,722	$ 215,920
VGT-PNG	3	2.94%	3	29,988	$ 4.5196	$ 135,534	$ 4.0056	$ 120,119	$ 4.0090	$ 120,222	$ (103)	$ 0.3146	$ 9,433	$ 129,552
VGT-NMU	4	3.92%	4	39,984	$ 4.5196	$ 180,712	$ 4.0056	$ 160,158	$ 4.0090	$ 160,296	$ (138)	$ 0.3146	$ 12,578	$ 172,736
Centra	4	3.92%	4	39,984	$ 4.5196	$ 180,712	$ 4.0056	$ 160,158	$ 4.0090	$ 160,296	$ (138)	$ 0.3146	$ 12,578	$ 172,736
Total	102	100.0%	102	1,019,898	$ 4.5196	$ 4,609,539	$ 4.0056	$ 4,085,261	$ 4.0090	$ 4,088,771	$ (3,510)	$ 0.3146	$ 320,828	$ 4,406,089

Dec-10

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/27/10		21	210,000	$ 5.5000	$ 1,155,000	$ 3.9920	$ 894,600	$ 3.9920	$ 894,600	$ -	$ 0.4600	$ 96,600	$ 991,200
2	06/17/10		21	210,000	$ 6.0000	$ 1,260,000	$ 3.9920	$ 894,600	$ 3.9920	$ 894,600	$ -	$ 0.5300	$ 111,300	$ 1,005,900
3	07/13/10		21	210,000	$ 5.5000	$ 1,155,000	$ 3.9920	$ 894,600	$ 3.9920	$ 894,600	$ -	$ 0.3900	$ 81,900	$ 976,500
4	08/24/10		25	250,000	$ 4.5000	$ 1,125,000	$ 3.9920	$ 1,065,000	$ 3.9920	$ 1,065,000	$ -	$ 0.3600	$ 90,000	$ 1,155,000
5	09/17/10		26	260,000	$ 4.5000	$ 1,170,000	$ 3.9920	$ 1,107,600	$ 3.9920	$ 1,107,600	$ -	$ 0.2780	$ 72,280	$ 1,179,880
6	10/07/10		28	280,000	$ 4.5000	$ 1,260,000	$ 3.9920	$ 1,192,800	$ 3.9920	$ 1,192,800	$ -	$ 0.0800	$ 22,400	$ 1,215,200
7														
8														
9														
10														
Total			142	1,420,000		$ 7,125,000		$ 6,049,200		$ 6,049,200	$ -		$ 474,480	$ 6,523,680
						$ 5.0176		$ 4.2600		$ 4.2600	$ -		$ 0.3341	$ 4.5941
NNG-PNG	101	71.13%	101	1,010,046	$ 5.0176	$ 5,068,013	$ 4.2600	$ 4,302,796	$ 4.2600	$ 4,302,796	$ -	$ 0.3341	$ 337,498	$ 4,640,294
NNG-NMU	14	9.86%	14	140,012	$ 5.0176	$ 702,525	$ 4.2600	$ 596,451	$ 4.2600	$ 596,451	$ -	$ 0.3341	$ 46,784	$ 643,235
GLGT-PNG	4	2.82%	4	40,044	$ 5.0176	$ 200,925	$ 4.2600	$ 170,587	$ 4.2600	$ 170,587	$ -	$ 0.3341	$ 13,380	$ 183,968
GLGT-NMU	9	6.34%	9	90,028	$ 5.0176	$ 451,725	$ 4.2600	$ 383,519	$ 4.2600	$ 383,519	$ -	$ 0.3341	$ 30,082	$ 413,601
VGT-PNG	3	2.11%	3	29,962	$ 5.0176	$ 150,338	$ 4.2600	$ 127,638	$ 4.2600	$ 127,638	$ -	$ 0.3341	$ 10,012	$ 137,650
VGT-NMU	6	4.23%	6	60,066	$ 5.0176	$ 301,388	$ 4.2600	$ 255,881	$ 4.2600	$ 255,881	$ -	$ 0.3341	$ 20,071	$ 275,952
Centra	5	3.52%	5	49,984	$ 5.0176	$ 250,800	$ 4.2600	$ 212,932	$ 4.2600	$ 212,932	$ -	$ 0.3341	$ 16,702	$ 229,634
Total	142	100.0%	142	1,420,142	$ 5.0176	$ 7,125,713	$ 4.2600	$ 6,049,805	$ 4.2600	$ 6,049,805	$ -	$ 0.3341	$ 474,527	$ 6,524,332

Jan-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	05/27/10		22	220,000	$ 5.5000	$ 1,210,000	$ 4.2630	$ 975,700	$ 4.2630	$ 975,700	$ -	$ 0.5950	$ 130,900	$ 1,106,600
2	06/29/10		25	250,000	$ 5.5000	$ 1,375,000	$ 4.2630	$ 1,108,750	$ 4.2630	$ 1,108,750	$ -	$ 0.6250	$ 156,250	$ 1,265,000
3	07/07/10		27	270,000	$ 5.5000	$ 1,485,000	$ 4.2630	$ 1,197,450	$ 4.2630	$ 1,197,450	$ -	$ 0.6100	$ 164,700	$ 1,362,150
4	08/31/10		28	280,000	$ 5.0000	$ 1,400,000	$ 4.2630	$ 1,241,800	$ 4.2630	$ 1,241,800	$ -	$ 0.3000	$ 84,000	$ 1,325,800
5	09/17/10		29	290,000	$ 5.0000	$ 1,450,000	$ 4.2630	$ 1,286,150	$ 4.2630	$ 1,286,150	$ -	$ 0.2230	$ 64,670	$ 1,350,820
6	10/07/10		31	310,000	$ 4.5000	$ 1,395,000	$ 4.2630	$ 1,374,850	$ 4.2630	$ 1,374,850	$ -	$ 0.2040	$ 63,240	$ 1,438,090
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Total	Total		162	1,620,000		$ 8,315,000		$ 7,184,700		$ 7,184,700	$ -		$ 663,760	$ 7,848,460
						$ 5.1327		$ 4.4350		$ 4.4350	$ -		$ 0.4097	$ 4.8447
NNG-PNG	117	72.22%	117	1,169,964	$ 5.1327	$ 6,005,093	$ 4.4350	$ 5,188,790	$ 4.4350	$ 5,188,790	$ -	$ 0.4097	$ 479,367	$ 5,668,158
NNG-NMU	14	8.64%	14	139,968	$ 5.1327	$ 718,416	$ 4.4350	$ 620,758	$ 4.4350	$ 620,758	$ -	$ 0.4097	$ 57,349	$ 678,107
GLGT-PNG	5	3.09%	5	50,058	$ 5.1327	$ 256,934	$ 4.4350	$ 222,007	$ 4.4350	$ 222,007	$ -	$ 0.4097	$ 20,510	$ 242,517
GLGT-NMU	9	5.56%	9	90,072	$ 5.1327	$ 462,314	$ 4.4350	$ 399,469	$ 4.4350	$ 399,469	$ -	$ 0.4097	$ 36,905	$ 436,374
VGT-PNG	4	2.47%	4	40,014	$ 5.1327	$ 205,381	$ 4.4350	$ 177,462	$ 4.4350	$ 177,462	$ -	$ 0.4097	$ 16,395	$ 193,857
VGT-NMU	7	4.32%	7	69,984	$ 5.1327	$ 359,208	$ 4.4350	$ 310,379	$ 4.4350	$ 310,379	$ -	$ 0.4097	$ 28,674	$ 339,053
Centra	6	3.70%	6	59,940	$ 5.1327	$ 307,655	$ 4.4350	$ 265,834	$ 4.4350	$ 265,834	$ -	$ 0.4097	$ 24,559	$ 290,393
Total	162	100.0%	162	1,620,000	$ 5.1327	$ 8,315,000	$ 4.4350	$ 7,184,700	$ 4.4350	$ 7,184,700	$ -	$ 0.4097	$ 663,760	$ 7,848,460

Feb-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	05/27/10		17	170,000	$ 5.5000	$ 935,000	$ 4.3020	$ 755,140	$ 4.3020	$ 755,140	$ -	$ 0.6250	$ 106,250	$ 861,390
2	06/22/10		22	220,000	$ 5.5000	$ 1,210,000	$ 4.3020	$ 977,240	$ 4.3020	$ 977,240	$ -	$ 0.7200	$ 158,400	$ 1,135,640
3	07/07/10		24	240,000	$ 5.5000	$ 1,320,000	$ 4.3020	$ 1,066,080	$ 4.3020	$ 1,066,080	$ -	$ 0.6400	$ 153,600	$ 1,219,680
4	08/31/10		24	240,000	$ 5.0000	$ 1,200,000	$ 4.3020	$ 1,066,080	$ 4.3020	$ 1,066,080	$ -	$ 0.3350	$ 80,400	$ 1,146,480
5	09/17/10		25	250,000	$ 5.0000	$ 1,250,000	$ 4.3020	$ 1,110,500	$ 4.3020	$ 1,110,500	$ -	$ 0.2700	$ 67,500	$ 1,178,000
6	10/07/10		25	250,000	$ 4.5000	$ 1,125,000	$ 4.3020	$ 1,110,500	$ 4.3020	$ 1,110,500	$ -	$ 0.2660	$ 66,500	$ 1,177,000
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Total			137	1,370,000		$ 7,040,000		$ 6,085,540		$ 6,085,540	$ -		$ 632,650	$ 6,718,190
						$ 5.1387		$ 4.4420		$ 4.4420	$ -		$ 0.4618	$ 4.9038
NNG-PNG	98	71.53%	98	979,961	$ 5.1387	$ 5,035,712	$ 4.4420	$ 4,352,987	$ 4.4420	$ 4,352,987	$ -	$ 0.4618	$ 452,535	$ 4,805,521
NNG-NMU	12	8.76%	12	120,012	$ 5.1387	$ 616,704	$ 4.4420	$ 533,093	$ 4.4420	$ 533,093	$ -	$ 0.4618	$ 55,420	$ 588,513
GLGT-PNG	4	2.92%	4	40,004	$ 5.1387	$ 205,568	$ 4.4420	$ 177,698	$ 4.4420	$ 177,698	$ -	$ 0.4618	$ 18,473	$ 196,171
GLGT-NMU	8	5.84%	8	80,008	$ 5.1387	$ 411,136	$ 4.4420	$ 355,396	$ 4.4420	$ 355,396	$ -	$ 0.4618	$ 36,947	$ 392,342
VGT-PNG	4	2.92%	4	40,004	$ 5.1387	$ 205,568	$ 4.4420	$ 177,698	$ 4.4420	$ 177,698	$ -	$ 0.4618	$ 18,473	$ 196,171
VGT-NMU	6	4.38%	6	60,006	$ 5.1387	$ 308,352	$ 4.4420	$ 266,547	$ 4.4420	$ 266,547	$ -	$ 0.4618	$ 27,710	$ 294,257
Centra	5	3.65%	5	50,005	$ 5.1387	$ 256,960	$ 4.4420	$ 222,122	$ 4.4420	$ 222,122	$ -	$ 0.4618	$ 23,092	$ 245,214
Total	137	100.0%	137	1,370,000	$ 5.1387	$ 7,040,000	$ 4.4420	$ 6,085,540	$ 4.4420	$ 6,085,540	$ -	$ 0.4618	$ 632,650	$ 6,718,190

Mar-11

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	05/25/10		14	140,000	$ 5.5000	$ 770,000	$ 4.2470	$ 612,220	$ 4.2470	$ 612,220	$ -	$ 0.5600	$ 78,400	$ 690,620
2	06/17/10		19	190,000	$ 6.0000	$ 1,140,000	$ 4.2470	$ 830,870	$ 4.2470	$ 830,870	$ -	$ 0.6550	$ 124,450	$ 955,320
3	07/13/10		17	170,000	$ 5.5000	$ 935,000	$ 4.2470	$ 743,410	$ 4.2470	$ 743,410	$ -	$ 0.5500	$ 93,500	$ 836,910
4	08/25/10		21	210,000	$ 4.5000	$ 945,000	$ 4.2470	$ 918,330	$ 4.2470	$ 918,330	$ -	$ 0.4850	$ 101,850	$ 1,020,180
5	09/15/10		22	220,000	$ 5.0000	$ 1,100,000	$ 4.2470	$ 962,060	$ 4.2470	$ 962,060	$ -	$ 0.2900	$ 63,800	$ 1,025,860
6	10/07/10		22	220,000	$ 4.5000	$ 990,000	$ 4.2470	$ 962,060	$ 4.2470	$ 962,060	$ -	$ 0.2850	$ 62,700	$ 1,024,760
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Total			115	1,150,000		$ 5,880,000		$ 5,028,950		$ 5,028,950	$ -		$ 524,700	$ 5,553,650
						$ 5.1130		$ 4.3730		$ 4.3730	$ -		$ 0.4563	$ 4.8293
NNG-PNG	82	71.30%	82	819,950	$ 5.1130	$ 4,192,440	$ 4.3730	$ 3,585,641	$ 4.3730	$ 3,585,641	$ -	$ 0.4563	$ 374,111	$ 3,959,752
NNG-NMU	10	8.70%	10	100,050	$ 5.1130	$ 511,560	$ 4.3730	$ 437,519	$ 4.3730	$ 437,519	$ -	$ 0.4563	$ 45,649	$ 483,168
GLGT-PNG	4	3.48%	4	40,020	$ 5.1130	$ 204,624	$ 4.3730	$ 175,007	$ 4.3730	$ 175,007	$ -	$ 0.4563	$ 18,260	$ 193,267
GLGT-NMU	7	6.09%	7	70,035	$ 5.1130	$ 358,092	$ 4.3730	$ 306,263	$ 4.3730	$ 306,263	$ -	$ 0.4563	$ 31,954	$ 338,217
VGT-PNG	3	2.61%	3	30,015	$ 5.1130	$ 153,468	$ 4.3730	$ 131,256	$ 4.3730	$ 131,256	$ -	$ 0.4563	$ 13,695	$ 144,950
VGT-NMU	5	4.35%	5	50,025	$ 5.1130	$ 255,780	$ 4.3730	$ 218,759	$ 4.3730	$ 218,759	$ -	$ 0.4563	$ 22,824	$ 241,584
Centra	4	3.48%	4	40,020	$ 5.1130	$ 204,624	$ 4.3730	$ 175,007	$ 4.3730	$ 175,007	$ -	$ 0.4563	$ 18,260	$ 193,267
Total	115	100.0%	115	1,150,115	$ 5.1130	$ 5,880,588	$ 4.3730	$ 5,029,453	$ 4.3730	$ 5,029,453	$ -	$ 0.4563	$ 524,752	$ 5,554,205

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			87	870,000	$ 5.4253	$ 4,720,000	$ 4.3205	$ 3,758,830	$ 4.3205	$ 3,758,830	$ -	$ 0.5387	$ 468,700	$ 4,227,530
2			102	1,020,000	$ 5.6225	$ 5,735,000	$ 4.3263	$ 4,412,810	$ 4.3263	$ 4,412,810	$ -	$ 0.6212	$ 633,650	$ 5,046,460
3			104	1,040,000	$ 5.4279	$ 5,645,000	$ 4.3297	$ 4,502,890	$ 4.3297	$ 4,502,890	$ -	$ 0.5555	$ 577,700	$ 5,080,590
4			118	1,180,000	$ 4.7203	$ 5,570,000	$ 4.3161	$ 5,093,010	$ 4.3161	$ 5,093,010	$ -	$ 0.3494	$ 412,250	$ 5,505,260
5			122	1,220,000	$ 4.7295	$ 5,770,000	$ 4.3166	$ 5,266,310	$ 4.3181	$ 5,268,110	$ (1,800)	$ 0.2451	$ 299,050	$ 5,565,360
6			125	1,250,000	$ 4.4240	$ 5,530,000	$ 4.3202	$ 5,400,210	$ 4.3215	$ 5,401,920	$ (1,710)	$ 0.1801	$ 225,100	$ 5,625,310
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Total			658	6,580,000		$ 32,970,000		$ 28,434,060		$ 28,437,570	$ (3,510)		$ 2,616,450	$ 31,050,510
						$ 5.0106		$ 4.3213		$ 4.3218	$ (0.0005)		$ 0.3976	$ 4.7189
NNG-PNG	472	71.73%	472	4,720,031	$ 5.0106	$ 23,650,370	$ 4.3213	$ 20,396,604	$ 4.3218	$ 20,399,122	$ (2,518)	$ 0.3976	$ 1,876,858	$ 22,273,462
NNG-NMU	59	8.97%	59	590,029	$ 5.0106	$ 2,956,420	$ 4.3213	$ 2,549,682	$ 4.3218	$ 2,549,997	$ (315)	$ 0.3976	$ 234,617	$ 2,784,299
GLGT-PNG	20	3.04%	20	200,032	$ 5.0106	$ 1,002,288	$ 4.3213	$ 864,395	$ 4.3218	$ 864,502	$ (107)	$ 0.3976	$ 79,540	$ 943,936
GLGT-NMU	38	5.78%	38	379,995	$ 5.0106	$ 1,904,018	$ 4.3213	$ 1,642,067	$ 4.3218	$ 1,642,270	$ (203)	$ 0.3976	$ 151,100	$ 1,793,167
VGT-PNG	17	2.58%	17	170,027	$ 5.0106	$ 851,945	$ 4.3213	$ 734,736	$ 4.3218	$ 734,827	$ (91)	$ 0.3976	$ 67,609	$ 802,345
VGT-NMU	28	4.26%	28	279,979	$ 5.0106	$ 1,402,874	$ 4.3213	$ 1,209,869	$ 4.3218	$ 1,210,019	$ (149)	$ 0.3976	$ 111,330	$ 1,321,199
Centra	24	3.65%	24	239,973	$ 5.0106	$ 1,202,416	$ 4.3213	$ 1,036,990	$ 4.3218	$ 1,037,118	$ (128)	$ 0.3976	$ 95,422	$ 1,132,412
Total	658	100.0%	658	6,580,066	$ 5.0106	$ 32,970,330	$ 4.3213	$ 28,434,344	$ 4.3218	$ 28,437,854	$ (3,510)	$ 0.3976	$ 2,616,476	$ 31,050,821