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 Viking 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 5 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 Entitlement	)	Docket No. _______________
for its Viking 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 Viking Gas Transmission Company (VGT or Viking) system. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2010.

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 Viking 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 Viking Gas Transmission Company (VGT or Viking) 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. <u>Summary of Filing</u>

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

2. <u>Service</u>

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. <u>General Filing Information</u>

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

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 Viking 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 Viking Gas Transmission (VGT or Viking) system. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2010.

II. DISCUSSION

A. MERC's PNG-VGT Design Day Requirements

MERC's 2010-2011 PNG-VGT design day requirements increased 401 Mcf (or approximately 5.82 percent) from 6,891 Mcf to 7,292 Mcf.

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

	Reserve Margin 2010-20112010-2011 Heating Season	Reserve Margin Heating Season	Change
VGT-PNG	19.62%	10.65%	8.97%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for PNG-VGT for the 2010-2011 heating season is positive.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day requirement for PNG-VGT is 7,292 Dth as calculated in Attachment 1, page 2 and Attachment 3.

For the Demand Entitlement filing effective November 1, 2009, the total Design Day capacity for PNG-VGT is 8,723 Dth as calculated in Attachment 3.

The difference between the total Design Day requirement and total Design Day capacity results in a 19.62% positive 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 **<u>Regression Generation of Net Daily Metered Volumes</u>** consisted of:

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

[1] 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.

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[2]. An unfortunate, but unavoidable consequence was that this data was based on monthly billing cycles that introduce billing lag, meter read lag (not all meters were read every month, 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[3], calendar month, (service) area, city, location, zip

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

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

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 on the highest monthly total from the prior winter was then used to calculate the amount to subtract from the results of the data regressions for each demand area:

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

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

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

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

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

NMU-GLGT

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

NMU-VGT

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

PNG-NNG

Taconites / Direct Connects =

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

PNG-NNG

OSEU (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 10. The daily estimate is compared to actual consumption. The actual volumes is 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. The calculated base load natural gas usage at zero heating degree days is 1,142 Dth which includes interruptible and transportation volumes. Since daily volume consumption is not available for all interruptible and transportation customers, MERC is not able to determine an exact number to deduct from the 1,142 Dth to determine the firm base load natural gas consumption at zero (0) HDD.

Average Customer Counts

In the 2007 demand entitlement dockets, MERC agreed to include average customer counts which is provided in Attachment 11.

C. MERC's Specific VGT Proposed Demand-Related Changes

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, there is no change in the amount of firm transportation capacity actually available to MERC-PNG-VGT 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 6, MERC-PNG-VGT proposes a decrease in the Viking Backhaul contract and the NNG Chisago contract that delivers gas into the VGT system for design day deliverability for the upcoming heating season.

MERC also purchased a Wadena Call Option on VGT for PNG-VGT and NMU (VGT) customers. The transaction allows MERC to call on gas up to 1,098 Dth/day from December 1, 2010 through February 28, 2011. The right to call on the gas costs $.03 Dth for the 1,098 Dth/day call rights for the 90 day period (December 1, 2010 through February 28, 2011. The option substituted the need to contract for firm backhaul on VGT to meet the design day. The cost of VGT would have been approximately $12,409 compared to the $2,965 option cost.

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC-PNG-GLGT terminated the Nexen PSO and replaced it with AECO Storage. To deliver the supply from storage to MERC's NMU markets, MERC entered in an AECO/Emerson swap. MERC sells gas at the storage point (AECO) to a supplier and MERC buys an equivalent volume at Emerson/Spruce, which MERC then transports to its PNG-GLGT, PNG-VGT and NMU (GLGT, VGT and Centra) customers. The swap substituted the need to contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce. The cost of TCPL would have been approximately $758,222 compared to the $450,195 to swap the gas.

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

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

ii. Total premium cost to enter into the financial Call Options on behalf of MERC's firm customers amounted to $68,012 for the 2010-2011 winter. Please see Attachment 5.

iii. MERC entered into 17 contracts (10,000/contract) or 170,000. Total premium per contract is approximately $.4001. Please see Attachment 5.

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

v. Please see Attachment 5 for the various contract prices.

vi. MERC entered into 10 futures contracts (10,000/contract) or 100,000,

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. <u>Gas Supply.</u>

The PNG-VGT 2010-2011 Winter Portfolio Plan - Minnesota Energy Resources Corporation for VGT gas supply purchases for the Hedging Plan is in Attachment 9, page 2. This Attachment includes the projected sales number by month for the November 2010 through March 2011 period as well as the planned physical fixed price, financial call options and storage and/or exchange volumes by month.

F. Price Volatility

MERC's 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 $4.9473. Please see Attachment 12, page 1 of 3. MERC is projecting the AECO Storage WACOG for PNG-VGT to be approximately $3.7863. 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 12, 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 12, 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 $4.31 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 and 2, and on page 1 of Attachment 7. MERC has also calculated the rate impact of moving the cost recovery of FDD Storage contracts from the demand cost recovery portion of the monthly PGA to the commodity cost recovery portion of the monthly PGA. Attachment 4, pages 3 and 4, and Attachment 7, page 2, illustrate the rate impact created by this shift in cost recovery.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 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 - VGT

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2010
VGT

Design Day Requirement		7,292
Total Entitlement on Peak Day(excl. Peak Shaving)		8,723
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 7)	5,188
Firm Annual Throughput - Minnesota		579,037
No. of Firm Customers		4,675
DPS Load Factor Calculation		30.58%

MINNESOTA ENERGY RESOURCES - PNG

MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2010
VGT

Pipeline Group	Nov09-Mar 10 Avg. 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									
	4,675	109	768	80	10,329	2,936	7,393	-1.4%	7,292
Total	4,675								7,292
OFF PEAK									
	4,675	57	768	80	6,220	1,881	4,339	-1.4%	4,280
Total	4,675								4,280

Footnote 1: Regression Total is based on total through-put data.
Footnote 2: Regression Adjustment substracts out Interruptible, Transportation and Joint Interruptible volumes and adds Firm Joint volumes.
Footnote 3: Total equals Regression Total minus Regression Adjustment.

*All requirement adjusted for customer growth

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND PER CUSTOMER

NOVEMBER 1, 2010

VGT

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
10/11	4,675	7,292	1.56
09/10	4,408	6,891	1.56
08/09	4,635	7,420	1.60
07/08	4,586	8,135	1.77
06/07	4,523	8,112	1.79
05/04	4,502	7,598	1.69
04/03	4,471	7,423	1.66

Attachment 2

MINNESOTA ENERGY RESOURCES - PNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2010

VGT

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	160,081	407,566	567,647
SVI	56,249	139,065	195,314
SVJ	3,438	7,952	11,390
LVI	0	0	0
Total	219,768	554,583	774,351

Attachment 3

MINNESOTA ENERGY RESOURCES - PNG

ENTITLEMENT LEVELS

PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2010

VGT

Type of Capacity or Entitlement		Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
AF0012		3,527	0	3,527
AF0014 (Dec-Feb) *		1,098	0	1,098
AF0016		1,000	0	1,000
AF0102		2,000	0	2,000
NNG-TF12 Base	112495	255	(255)	0
NNG-TF12 Variable	112495	178	(178)	0
NNG-TF5 Chisago	112495	105	(105)	0
NNG-TFX 12 Chisago	112486	389	(389)	0
NNG-TFX 5 Chisago	112486	172	(172)	0
Chisago Backhaul*	RF0361	0	0	0
Wadena Delivered Option		0	1,098	1,098
Heating Season Total		7,625	0	8,723
Non-Heating Season Total		7,170	(643)	6,527
Total Entitlement		7,625	0	8,723
Heating Season Forecasted Design Day		6,891	401	7,292
Non-Heating Season Forecasted Design Day		4,228	52	4,280
Heating Season Capacity Surplus/Shortage		734	697	1,431
Non-Heating Season Capacity Surplus/Shortage		2,299	(52)	2,247
Reserve Margin		10.65%		19.62%

*Not included in total firm entitlement

(1) Increase entitlement to ensure adequate reserve margin against design day.

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2010

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-08-XXXX Oct .08	Last Demand Change G011- M-09-XXXX Oct. 09	VGT 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:				**132**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost	$1.2591	$1.2591	$1.0908	$0.9994	$0.8815	-29.99%	-19.18%	-11.79%	($0.1179)
Commodity Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Cost of Gas	$11.1308	$9.8487	$6.3855	$6.5605	$6.3844	-42.64%	-0.02%	-2.68%	($0.1761)
Avg Annual Cost	$1,469.27	$1,300.03	$842.89	$865.99	$842.74	-42.64%	-0.02%	-2.68%	($23.24)
Effect of proposed commodity change on average annual bills:									($7.69)
Effect of proposed demand change on average annual bills:									($15.56)
2) Small Vol. Interruptible: Avg. Annual Use:				**3,499**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost									
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Cost of Gas	$9.4888	$8.2067	$4.9118	$4.9546	$4.8964	-48.40%	-0.31%	-1.18%	($0.0582)
Avg Annual Cost	$33,201.31	$28,715.24	$17,186.39	$17,336.15	$17,132.40	-48.40%	-0.31%	-1.18%	($203.74)
Effect of proposed commodity change on average annual bills:									($203.74)
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:				**113,688**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost									
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$7.3225	$4.0276	$4.1113	$4.0531	-52.90%	0.63%	-1.42%	($0.0582)
Avg Annual Cost	$978,239.76	$832,480.38	$457,889.79	$467,405.47	$460,785.57	-52.90%	0.63%	-1.42%	($6,619.90)
Effect of proposed commodity change on average annual bills:									($6,619.90)
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:				**3,893**	**Mcf**				
Agg. Annual CD Units:				**15**					
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost	$3.4671	$3.4671	$3.4671	$3.4671	$3.4671	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.3592	$1.2434	$1.2434	$1.1681	$1.1681	225.19%	-6.06%	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$2.0724	$1.8000	$1.8000	-13.14%	-13.14%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$8.2067	$4.9118	$4.9546	$4.8964	-43.10%	-0.31%	-1.18%	($0.0582)
Total Demand Cost	$5.5395	$5.5395	$5.5395	$5.2671	$5.2671	-4.92%	-4.92%	0.00%	$0.0000
Avg Annual Cost	$33,580.80	$32,031.78	$19,204.73	$19,367.26	$19,140.58	-43.00%	-0.33%	-1.17%	($226.68)
Effect of proposed commodity change on average annual bills:									($226.68)
Effect of proposed demand change on average annual bills:									$0.00

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
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA)
Viking Current Cost of Gas

II. VIKING GAS TRANSMISSION'S RATES -- CURRENT COST OF GAS EFFECTIVE						**01-Nov-10**	**CURRENT**	
	Commodity From Schedule D					$0.37171	/therm	
III. ANNUAL SALES --								
	Total Annual Sales					8,444,190	therms	
	Firm Annual Sales (GS-5)					6,019,240	therms	
IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE						**01-Nov-10**	**CURRENT**	
			Monthly Entitlemen	**Months**	**Rate $/Dth**		**Contract Cost**	**$/therm**
A. GS-4	FT-A	AF0012	3,527	12	$3.4671	=	$146,742	$0.02438
	FT-A	AF0014 *	1,098	3	$3.4671	=	$11,421	$0.00190
	FT-A	AF0016	1,000	12	$3.4671	=	$41,605	$0.00691
	FT-A	AF0102	2,000	12	$3.4671	=	$83,210	$0.01382
	NNG-TF12 Base	112495	0	12	$7.5776	=	$0	$0.00000
	NNG-TF12 Variable	112495	0	12	$9.0926	=	$0	$0.00000
	NNG-TF5 Chisago	112495	0	5	$15.1530	=	$0	$0.00000
	NNG-TFX 12 Chisago	112486	0	12	$9.6288	=	$0	$0.00000
	NNG-TFX 5 Chisago	112486	0	5	$15.1530	=	$0	$0.00000
	FT-A Backhaul	AF0160	0	4	$3.7671	=	$0	$0.00000
	Wadena Delivered Option		1,098	3	$0.9000	=	$2,965	$0.00049
	Total Demand Cost						$285,942	$0.04750
	Nexen Exchange		0	1	$1.77000	=	$0	$0.00000
	Niska Storage		128,469	1	$1.42643	=	$183,659	$0.03051
	AECO/Emerson Swap		128,464	1	$0.47500	=	$61,020	$0.01014
	Total Storage Demand						$244,679	$0.04065
	Rate Case 2008 Firm Annual Sales in therms						6,019,240	
	Current Demand Cost of Gas $/therm							$0.08815
	Current T-17 Commodity Cost of Gas							$0.37171
	Call Option Premium				$9,433.28	8,444,190		$0.00112
	GS-5 Total Current Commodity Cost of Gas $/therm							$0.37283
	Current Total Cost of Gas $/therm							$0.46098
B. SVI-4	Current Commodity Cost of Gas/CCf							$0.37283
C. SJ-4	Current Demand Cost of Gas/CCf							$0.34671
	Current Commodity Cost of Gas/CCf							$0.37283
D. LVI-4	Current Commodity Cost of Gas/CCf							$0.37283

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

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2010

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-08-XXXX Oct .08	Last Demand Change G011- M-09-XXXX Oct. 09	VGT 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:				**132**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost	$1.2591	$1.2591	$1.0908	$0.9994	$0.4750	-62.27%	-56.45%	-52.47%	($0.5244)
Commodity Margin	$1.6263	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Cost of Gas	$11.1308	$9.8487	$6.3855	$6.5605	$6.2677	-43.69%	-1.85%	-4.46%	($0.2928)
Avg Annual Cost	$1,469.27	$1,300.03	$842.89	$865.99	$827.33	-43.69%	-1.85%	-4.46%	($38.65)
Effect of proposed commodity change on average annual bills:									$30.56
Effect of proposed demand change on average annual bills:									($69.21)
2) Small Vol. Interruptible: Avg. Annual Use:				**3,499**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost									
Commodity Margin	$1.2434	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Cost of Gas	$9.4888	$8.2067	$4.9118	$4.9546	$5.1861	-45.34%	5.59%	4.67%	$0.2315
Avg Annual Cost	$33,201.31	$28,715.24	$17,186.39	$17,336.15	$18,146.28	-45.34%	5.59%	4.67%	$810.13
Effect of proposed commodity change on average annual bills:									$810.13
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:				**113,688**	**Mcf**				
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost									
Commodity Margin	$0.3592	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$7.3225	$4.0276	$4.1113	$4.3428	-49.53%	7.83%	5.63%	$0.2315
Avg Annual Cost	$978,239.76	$832,480.38	$457,889.79	$467,405.47	$493,727.89	-49.53%	7.83%	5.63%	$26,322.42
Effect of proposed commodity change on average annual bills:									$26,322.42
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:				**3,893**	**Mcf**				
Agg. Annual CD Units:				**15**					
Commodity Cost	$8.2454	$6.9633	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost	$3.4671	$3.4671	$3.4671	$3.4671	$3.4671	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.3592	$1.2434	$1.2434	$1.1681	$1.1681	225.19%	-6.06%	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$2.0724	$1.8000	$1.8000	-13.14%	-13.14%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$8.2067	$4.9118	$4.9546	$5.1861	-39.73%	5.59%	4.67%	$0.2315
Total Demand Cost	$5.5395	$5.5395	$5.5395	$5.2671	$5.2671	-4.92%	-4.92%	0.00%	$0.0000
Avg Annual Cost	$33,580.80	$32,031.78	$19,204.73	$19,367.26	$20,268.62	-39.64%	5.54%	4.65%	$901.35
Effect of proposed commodity change on average annual bills:									$901.35
Effect of proposed demand change on average annual bills:									$0.00

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
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA)
Viking Current Cost of Gas
Rate Impacts (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

II. VIKING GAS TRANSMISSION'S RATES -- CURRENT COST OF GAS EFFECTIVE						**01-Nov-10**	**CURRENT**		
	Commodity From Schedule D					$0.37171	/therm		
III. ANNUAL SALES --									
	Total Annual Sales					8,444,190	therms		
	Firm Annual Sales (GS-5)					6,019,240	therms		
IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE						**01-Nov-10**	**CURRENT**		
			Monthly Entitlemen	**Months**	**Rate $/Dth**			**Contract Cost**	**$/therm**
A. GS-4	FT-A	AF0012	3,527	12	$3.4671	=		$146,742	$0.02438
	FT-A	AF0014 *	1,098	3	$3.4671	=		$11,421	$0.00190
	FT-A	AF0016	1,000	12	$3.4671	=		$41,605	$0.00691
	FT-A	AF0102	2,000	12	$3.4671	=		$83,210	$0.01382
	NNG-TF12 Base	112495	0	12	$7.5776	=		$0	$0.00000
	NNG-TF12 Variable	112495	0	12	$9.0926	=		$0	$0.00000
	NNG-TF5 Chisago	112495	0	5	$15.1530	=		$0	$0.00000
	NNG-TFX 12 Chisago	112486	0	12	$9.6288	=		$0	$0.00000
	NNG-TFX 5 Chisago	112486	0	5	$15.1530	=		$0	$0.00000
	FT-A Backhaul	AF0160	0	4	$3.7671	=		$0	$0.00000
	Wadena Delivered Option		1,098	3	$0.9000	=		$2,965	$0.00049
	Total Demand Cost							$285,942	$0.04750
	Nexen Exchange		0	1	$1.77000	=		$0	$0.00000
	Niska Storage		128,469	0	$1.42643	=		$0	$0.00000
	AECO/Emerson Swap		128,464	0	$0.00000	=		$0	$0.00000
	Total Storage Demand							$0	$0.00000
	Rate Case 2008 Firm Annual Sales in therms							6,019,240	
	Current Demand Cost of Gas $/therm								$0.04750
	Current T-17 Commodity Cost of Gas								$0.37171
	Call Option Premium				$9,433.28	8,444,190			$0.00112
	Niska Storage		128,469	1	$1.42643	=		$183,659	$0.02175
	AECO/Emerson Swap		128,464	1	$0.47500	=		$61,020	$0.00723
	GS-5 Total Current Commodity Cost of Gas $/therm								$0.40180
	Current Total Cost of Gas $/therm								$0.44931
B. SVI-4	Current Commodity Cost of Gas/CCf								$0.40180
C. SJ-4	Current Demand Cost of Gas/CCf								$0.34671
	Current Commodity Cost of Gas/CCf								$0.40180
D. LVI-4	Current Commodity Cost of Gas/CCf								$0.40180

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 5

MINNESOTA ENERGY RESOURCES - PNG-VGT

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		667		645		645		357		968	3,244	100,000
		20,000		20,000		20,000		10,000		30,000		100,000

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		1,000		968		1,290		1,429		968	5,654	170,000
		30,000		30,000		40,000		40,000		30,000		170,000

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**	**$ 9,437**	**$ 0.3341**	**$ 10,024**	**$ 0.4097**	**$ 16,389**	**$ 0.4618**	**$ 18,472**	**$ 0.4563**	**$ 13,690**	**$ 0.4001**	**$ 68,012**

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED**

MINNESOTA ENERGY RESOURCES - PNG

2007-08 G011/M-06-XXXX	Quantity (Mcf)		2008-09 G011/M-07-XXXX	Quantity (Mcf)	
FT-A 12 months	3,527	2/	FT-A 12 months	6,527	2/
FT-A 3 months	1,098		FT-A 3 months	1,098	
FT-A (5 month backhaul)	915	1/	FT-A (5 month backhaul)	0	1/
NNG TF 12 mos. (backhaul)	1,098	1/	NNG TF 12 mos. (backhaul)	1,098	1/
TF12 (NNG)	1,108		TF12 (NNG)	172	
TF5 (NNG)	905		TF5 (NNG)	389	
FT-D 12 months	3,000		TFX12 (NNG)	432	
			TFX5 (NNG)	105	
			FT-D 12 months	0	
Total Design Day Capacity	8,540		Total Design Day Capacity	7,625	
Total Viking Transportation	8,540		Total Viking Transportation	7,625	
Total Annual Transportation	7,635		Total Annual Transportation	7,131	
Total Seasonal Transport	2,003		Total Seasonal Transport	1,592	
Percent Seasonal on Viking	23.5%		Percent Seasonal on Viking	20.9%	

2009-10 G011/M-08-XXXX	Quantity (Mcf)		2010-11 G011/M-09-XXXX	Quantity (Mcf)		Change in Quantity
FT-A 12 months	6,527		FT-A 12 months	6,527		0
FT-A 3 months	1,098		FT-A 3 months	1,098		0
FT-A (5 month backhaul)	0	1/	FT-A (5 month backhaul)	0	1/	0
NNG TF 12 mos. (backhaul)	1,098	1/	NNG TF 12 mos. (backhaul)	1,098	1/	0
TF12 (NNG)	432		TF12 (NNG)	0		(432)
TF5 (NNG)	105		TF5 (NNG)	0		(105)
TFX12 (NNG)	389		TFX12 (NNG)	0		(389)
TFX5 (NNG)	172		TFX5 (NNG)	0		(172)
FT-D 12 months	0		FT-D 12 months	0		0
Wadena Delivered Option	0		Wadena Delivered Option	1,098		1,098
Total Design Day Capacity	7,625		Total Design Day Capacity	8,723		1,098
Total Viking Transportation	7,625		Total Viking Transportation	8,723		1,098
Total Annual Transportation	7,348		Total Annual Transportation	7,625		277
Total Seasonal Transport	1,375		Total Seasonal Transport	2,196		821
Percent Seasonal on Viking	18.0%		Percent Seasonal on Viking	25.2%		7.14%

1/ The amount is excluded from the design day capacity since it is a backhaul to transport gas to Viking.

MINNESOTA ENERGY RESOURCES - PNG

General Service	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost of Gas	$1.2591	$1.0908	$0.9994	$0.8815	-29.99%	-19.18%	-11.79%	($0.1179)
Commodity Margin	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Cost of Gas	$11.1308	$6.3855	$6.5605	$6.3844	-42.64%	-0.02%	-2.68%	($0.1761)
Average Annual Usage (Mcf)	132	132	132	132				
Average Annual Total Cost of Gas	$1,469.27	$842.89	$865.99	$842.74	-42.64%	-0.02%	-2.68%	($23.24)

General Service	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost of Gas								$0.0000
Commodity Margin	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Cost of Gas	$9.4888	$4.9118	$4.9546	$4.8964	-48.40%	-0.31%	-1.18%	($0.0582)
Average Annual Usage (Mcf)	3,499	3,499	3,499	3,499				
Average Annual Total Cost of Gas	$33,201.31	$17,186.39	$17,336.15	$17,132.40	-48.40%	-0.31%	-1.18%	($203.74)

Large Volume Interruptible	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost of Gas								$0.0000
Commodity Margin	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$4.0276	$4.1113	$4.0531	-52.90%	0.63%	-1.42%	($0.0582)
Average Annual Usage (Mcf)	113,688	113,688	113,688	113,688				
Average Annual Total Cost of Gas	$978,239.76	$457,889.79	$467,405.47	$460,785.57	-52.90%	0.63%	-1.42%	($6,619.90)

Small Volume Firm/Interruptible	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$3.7283	-54.78%	1.63%	-1.54%	($0.0582)
Demand Cost of Gas	$3.4671	$3.4671	$3.4671	$3.4671	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.3592	$1.2434	$1.1681	$1.1681	225.19%	-6.06%	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$1.8000	$1.8000	-13.14%	-13.14%	0.00%	$0.0000
Total Commodity Cost	$8.6046	$4.9118	$4.9546	$4.8964	-43.10%	-0.31%	-1.18%	($0.0582)
Total Demand Cost	$5.5395	$5.5395	$5.2671	$5.2671	-4.92%	-4.92%	0.00%	$0.0000
Total Recovery	$14.1441	$10.4513	$10.2217	$10.1635	-28.14%	-2.75%	-0.57%	($0.0582)
Average Annual Usage (Mcf)*	3,893	3,893	3,893	3,893				
Average Annual CD units (Mcf)	15	15	15	15				
Average Annual Commodity Bill^	$33,580.80	$19,204.73	$19,367.26	$19,140.58	-43.00%	-0.33%	-1.17%	($226.68)

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Service	($0.0582)	-5.82%	($0.1179)	-11.79%	($0.1761)	-2.68%	($23.24)
Small Volume Interruptible	($0.0582)	-5.82%	$0.0000	0.00%	($0.0582)	-1.18%	($203.74)
Large Volume Interruptible	($0.0582)	-5.82%	$0.0000	0.00%	$0.0582	-1.42%	($6,619.90)
Small Volume Firm	($0.0582)	-5.82%	$0.0000	0.00%	$0.0000	0.00%	($226.68)

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

MINNESOTA ENERGY RESOURCES - PNG

General Service	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost of Gas	$1.2591	$1.0908	$0.9994	$0.4750	-62.27%	-56.45%	-52.47%	($0.5244)
Commodity Margin	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Cost of Gas	$11.1308	$6.3855	$6.5605	$6.2677	-43.69%	-1.85%	-4.46%	($0.2928)
Average Annual Usage (Mcf)	132	132	132	132				
Average Annual Total Cost of Gas	$1,469.27	$842.89	$865.99	$827.33	-43.69%	-1.85%	-4.46%	($38.65)

General Service	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost of Gas								$0.0000
Commodity Margin	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
Total Cost of Gas	$9.4888	$4.9118	$4.9546	$5.1861	-45.34%	5.59%	4.67%	$0.2315
Average Annual Usage (Mcf)	3,499	3,499	3,499	3,499				
Average Annual Total Cost of Gas	$33,201.31	$17,186.39	$17,336.15	$18,146.28	-45.34%	5.59%	4.67%	$810.13

Large Volume Interruptible	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost of Gas								$0.0000
Commodity Margin	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Cost of Gas	$8.6046	$4.0276	$4.1113	$4.3428	-49.53%	7.83%	5.63%	$0.2315
Average Annual Usage (Mcf)	113,688	113,688	113,688	113,688				
Average Annual Total Cost of Gas	$978,239.76	$457,889.79	$467,405.47	$493,727.89	-49.53%	7.83%	5.63%	$26,322.42

Small Volume Firm/Interruptible	Base Cost of Gas Change G011/MR08-836^	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$8.2454	$3.6684	$3.7865	$4.0180	-51.27%	9.53%	6.11%	$0.2315
Demand Cost of Gas	$3.4671	$3.4671	$3.4671	$3.4671	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.3592	$1.2434	$1.1681	$1.1681	225.19%	-6.06%	0.00%	$0.0000
Demand Margin	$2.0724	$2.0724	$1.8000	$1.8000	-13.14%	-13.14%	0.00%	$0.0000
Total Commodity Cost	$8.6046	$4.9118	$4.9546	$5.1861	-39.73%	5.59%	4.67%	$0.2315
Total Demand Cost	$5.5395	$5.5395	$5.2671	$5.2671	-4.92%	-4.92%	0.00%	$0.0000
Total Recovery	$14.1441	$10.4513	$10.2217	$10.4532	-26.09%	0.02%	2.27%	$0.2315
Average Annual Usage (Mcf)*	3,893	3,893	3,893	3,893				
Average Annual CD units (Mcf)	15	15	15	15				
Average Annual Commodity Bill^	$33,580.80	$19,204.73	$19,367.26	$20,268.62	-39.64%	5.54%	4.65%	$901.35

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Service	$0.2315	23.15%	($0.5244)	-52.47%	($0.2928)	-4.46%	($38.65)
Small Volume Interruptible	$0.2315	23.15%	$0.0000	0.00%	$0.2315	4.67%	$810.13
Large Volume Interruptible	$0.2315	23.15%	$0.0000	0.00%	($0.2315)	5.63%	$26,322.42
Small Volume Firm	$0.2315	23.15%	$0.0000	0.00%	$0.0000	0.00%	$901.35

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

MINNESOTA ENERGY RESOURCES - PNG

	Oct-10 Entitlement	Nov-10 Entitlement	Entitlement Change	Months	Oct. 2010 Tariff Rate	Oct. 2010 Total Cost	Nov. 2010 Total Cost	Entitlement Change
FT-A (AF0012)	3,527	3,527	0	12	$3.4671	$146,742	$146,742	$0
FT-A (AF0014)	1,098	1,098	0	3	$3.4671	$11,421	$11,421	$0
FT-A (AF0016)	1,000	1,000	0	12	$3.4671	$41,605	$41,605	$0
FT-A (AF0102)	2,000	2,000	0	12	$3.4671	$83,210	$83,210	$0
TF-12 (NNG) (112495)	255	0	-255	12	$7.5776	$23,149	$0	-$23,149
TFX-12 (NNG) (112495)	105	0	-105	12	$15.1530	$19,053	$0	-$19,053
TF-5 (NNG) (112495)	389	0	-389	5	$9.6288	$18,713	$0	-$18,713
TFX-5 (NNG) (112486)	172	0	-172	5	$15.1530	$13,049	$0	-$13,049
Chisago Backhaul	915	0	-915	5	$3.7671	$17,234	$0	-$17,234
Wadena Delivered Optio	0	1,098	1,098	3	$0.9000	$0	$2,965	$2,965
Nexen PSO	152,888	0	-152,888	1	$1.7700	$270,612	$0	-$270,612
Niska Storage	0	128,469	128,469	1	$1.4264	$0	$183,659	$183,659
AECO/Emerson Swap	0	128,464	128,464	1	$0.4750	$0	$61,020	$61,020
Total Demand Cost						$644,788	$530,622	-$114,166

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES - PNG

10/11 Winter Portfolio Plan - MERC VGT-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

VGT WINTER PLAN (PNG)

NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

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

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 10
VGT

MINNESOTA ENERGY RESOURCES - PNG

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

Base	1,142
Variable	78

Date	15.00% Bemidji Adjusted HDD	85.00% Fargo Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put
7/1/09	0	0	0	716	1,142
7/2/09	8	0	1	604	1,233
7/3/09	9	5	6	525	1,592
7/4/09	3	0	0	497	1,179
7/5/09	0	0	0	593	1,142
7/6/09	0	0	0	780	1,142
7/7/09	2	0	0	816	1,167
7/8/09	7	0	1	810	1,222
7/9/09	2	0	0	850	1,167
7/10/09	1	0	0	719	1,154
7/11/09	0	0	0	574	1,142
7/12/09	5	0	1	680	1,198
7/13/09	2	0	0	791	1,170
7/14/09	0	0	0	865	1,142
7/15/09	0	0	0	949	1,142
7/16/09	2	0	0	1,013	1,166
7/17/09	0	0	0	838	1,142
7/18/09	2	0	0	667	1,167
7/19/09	7	0	1	684	1,226
7/20/09	0	0	0	867	1,142
7/21/09	0	0	0	858	1,142
7/22/09	0	0	0	824	1,142
7/23/09	0	0	0	782	1,142
7/24/09	0	0	0	663	1,142
7/25/09	0	0	0	549	1,142
7/26/09	0	0	0	601	1,142
7/27/09	0	0	0	793	1,142
7/28/09	0	0	0	805	1,142
7/29/09	0	0	0	817	1,142
7/30/09	0	0	0	822	1,142
7/31/09	0	0	0	730	1,142
8/1/09	0	0	0	610	1,142
8/2/09	0	0	0	623	1,142
8/3/09	0	0	0	813	1,142
8/4/09	0	0	0	827	1,142
8/5/09	0	0	0	814	1,142
8/6/09	0	0	0	785	1,142
8/7/09	2	0	0	677	1,167
8/8/09	4	2	2	556	1,330
8/9/09	0	0	0	597	1,142
8/10/09	0	0	0	771	1,142
8/11/09	3	0	0	727	1,181
8/12/09	0	0	0	719	1,142
8/13/09	0	0	0	723	1,142
8/14/09	0	0	0	635	1,142
8/15/09	4	0	1	555	1,190
8/16/09	0	0	0	650	1,142
8/17/09	0	0	0	1,012	1,142

9/25/09	6	0	1	770	1,206
9/26/09	0	0	0	612	1,142
9/27/09	14	13	13	955	2,162
9/28/09	14	8	9	1,667	1,828
9/29/09	21	19	19	1,616	2,615
9/30/09	22	13	14	1,607	2,233
10/1/09	19	18	18	2,017	2,549
10/2/09	15	10	11	1,872	1,963
10/3/09	24	18	19	1,678	2,609
10/4/09	19	9	11	1,677	1,965
10/5/09	15	10	11	2,192	2,008
10/6/09	13	6	7	2,338	1,668
10/7/09	16	12	12	2,352	2,099
10/8/09	14	10	11	2,974	1,976
10/9/09	20	18	18	2,959	2,571
10/10/09	26	24	24	3,179	3,039
10/11/09	20	21	21	3,033	2,801
10/12/09	8	8	8	3,491	1,751
10/13/09	13	23	21	2,978	2,798
10/14/09	24	23	23	3,097	2,968
10/15/09	26	21	22	2,937	2,870
10/16/09	26	23	23	2,863	2,946
10/17/09	27	18	19	2,610	2,650
10/18/09	19	16	17	1,844	2,432
10/19/09	23	19	19	2,275	2,658
10/20/09	30	27	27	2,562	3,255
10/21/09	31	28	28	2,875	3,339
10/22/09	26	24	25	2,959	3,062
10/23/09	21	19	19	2,704	2,643
10/24/09	24	24	24	2,152	3,020
10/25/09	22	21	22	2,310	2,828
10/26/09	33	33	33	2,729	3,679
10/27/09	40	36	37	2,331	3,989
10/28/09	31	28	28	2,286	3,350
10/29/09	27	24	24	2,264	3,037
10/30/09	10	11	11	3,191	1,986
10/31/09	26	24	24	2,651	3,029
11/1/09	25	18	19	2,614	2,621
11/2/09	16	11	12	3,615	2,056
11/3/09	9	11	11	3,140	1,988
11/4/09	12	13	13	3,185	2,144
11/5/09	12	11	11	2,872	1,989
11/6/09	22	28	27	2,156	3,275
11/7/09	34	43	42	1,950	4,416
11/8/09	48	49	49	2,431	4,937
11/9/09	50	46	46	2,475	4,764
11/10/09	46	44	44	2,191	4,575
11/11/09	40	38	38	1,880	4,139
11/12/09	35	34	34	2,057	3,801
11/13/09	35	29	30	2,427	3,482
11/14/09	42	43	43	2,731	4,506
11/15/09	45	40	41	2,939	4,336
11/16/09	47	41	42	3,084	4,410
11/17/09	53	48	48	3,062	4,912
11/18/09	47	44	45	3,019	4,636
11/19/09	52	50	50	3,025	5,036
11/20/09	61	60	60	3,027	5,831
11/21/09	56	52	53	2,337	5,252
11/22/09	46	40	41	2,644	4,351
11/23/09	39	36	36	2,741	3,960
11/24/09	49	43	44	3,098	4,582
11/25/09	46	40	41	3.629	4.351

1/2/10	71	66	67	6,993	6,374
1/3/10	69	72	71	6,773	6,705
1/4/10	88	83	84	6,597	7,702
1/5/10	78	73	74	6,147	6,878
1/6/10	61	70	69	6,355	6,498
1/7/10	69	72	72	7,669	6,748
1/8/10	68	67	67	7,200	6,397
1/9/10	67	69	68	6,074	6,482
1/10/10	63	67	67	5,436	6,334
1/11/10	62	60	60	5,435	5,847
1/12/10	87	84	84	4,832	7,731
1/13/10	88	90	89	4,385	8,117
1/14/10	92	92	92	4,567	8,324
1/15/10	87	94	93	3,871	8,377
1/16/10	80	70	72	3,530	6,736
1/17/10	55	50	51	3,536	5,120
1/18/10	58	51	52	4,326	5,179
1/19/10	62	50	52	4,945	5,165
1/20/10	50	54	53	4,809	5,304
1/21/10	46	54	52	4,484	5,235
1/22/10	60	64	64	4,000	6,114
1/23/10	85	84	84	3,364	7,707
1/24/10	84	84	84	4,245	7,722
1/25/10	83	83	83	6,213	7,607
1/26/10	79	83	82	6,535	7,577
1/27/10	72	77	77	6,878	7,109
1/28/10	65	63	63	6,854	6,064
1/29/10	80	71	73	6,371	6,815
1/30/10	63	51	52	5,944	5,228
1/31/10	40	40	40	6,009	4,240
2/1/10	66	65	65	6,025	6,222
2/2/10	83	82	82	5,932	7,535
2/3/10	77	77	77	5,354	7,139
2/4/10	72	69	69	4,645	6,555
2/5/10	49	50	50	3,951	5,014
2/6/10	37	43	42	4,118	4,402
2/7/10	49	54	53	4,494	5,275
2/8/10	38	44	43	4,974	4,532
2/9/10	34	32	32	5,864	3,673
2/10/10	34	35	35	5,580	3,884
2/11/10	41	45	45	4,939	4,626
2/12/10	54	57	57	4,462	5,560
2/13/10	58	60	60	4,554	5,834
2/14/10	67	62	63	5,245	6,058
2/15/10	61	56	56	5,161	5,540
2/16/10	47	54	53	5,345	5,242
2/17/10	57	59	58	5,237	5,694
2/18/10	72	71	71	4,970	6,699
2/19/10	64	64	64	4,470	6,106
2/20/10	58	64	63	4,287	6,057
2/21/10	65	66	66	4,520	6,269
2/22/10	64	63	63	4,837	6,073
2/23/10	61	61	61	6,474	5,918
2/24/10	44	49	48	5,832	4,907
2/25/10	64	69	68	5,176	6,469
2/26/10	75	86	84	4,544	7,698
2/27/10	73	79	78	4,327	7,228
2/28/10	77	73	74	4,264	6,912
3/1/10	68	73	72	3,977	6,751
3/2/10	57	58	58	3,850	5,645
3/3/10	46	47	47	3,802	4,782
3/4/10	37	41	40	3,672	4,279

4/11/10	24	21	21	1,476	2,802
4/12/10	19	18	18	1,849	2,568
4/13/10	19	17	17	1,561	2,493
4/14/10	19	15	15	1,274	2,333
4/15/10	14	8	9	1,820	1,854
4/16/10	10	12	11	1,876	2,018
4/17/10	20	20	20	1,427	2,698
4/18/10	29	31	30	1,332	3,500
4/19/10	24	24	24	1,459	3,026
4/20/10	32	27	28	1,354	3,336
4/21/10	25	21	21	1,640	2,808
4/22/10	23	19	20	1,428	2,692
4/23/10	8	5	5	1,036	1,550
4/24/10	33	32	32	1,448	3,638
4/25/10	24	19	20	1,489	2,699
4/26/10	30	28	28	1,551	3,358
4/27/10	30	25	25	1,421	3,121
4/28/10	20	14	14	1,287	2,273
4/29/10	21	20	20	1,691	2,735
4/30/10	28	25	25	1,643	3,118
5/1/10	22	20	20	1,879	2,734
5/2/10	22	18	19	2,132	2,601
5/3/10	21	15	16	2,286	2,395
5/4/10	10	5	5	1,831	1,563
5/5/10	17	11	12	2,438	2,072
5/6/10	6	6	6	2,284	1,586
5/7/10	20	16	17	2,831	2,436
5/8/10	24	30	29	2,107	3,385
5/9/10	30	29	29	1,612	3,411
5/10/10	22	14	15	2,131	2,314
5/11/10	11	9	9	2,599	1,879
5/12/10	11	8	9	2,186	1,817
5/13/10	21	17	17	2,386	2,497
5/14/10	30	22	23	1,276	2,961
5/15/10	20	18	18	931	2,564
5/16/10	25	21	21	1,021	2,819
5/17/10	9	8	8	1,070	1,779
5/18/10	10	8	8	938	1,802
5/19/10	9	5	5	938	1,547
5/20/10	0	0	0	911	1,142
5/21/10	20	8	9	849	1,882
5/22/10	11	10	10	718	1,950
5/23/10	20	15	15	788	2,346
5/24/10	6	2	3	862	1,364
5/25/10	10	5	5	913	1,571
5/26/10	19	19	19	904	2,636
5/27/10	16	9	10	833	1,894
5/28/10	11	7	7	706	1,702
5/29/10	9	4	5	599	1,542
5/30/10	17	4	6	687	1,632
5/31/10	11	1	3	717	1,343
6/1/10	13	6	7	943	1,659
6/2/10	21	15	16	925	2,404
6/3/10	6	1	2	904	1,290
6/4/10	5	1	2	775	1,272
6/5/10	26	21	22	716	2,869
6/6/10	18	16	16	790	2,429
6/7/10	17	14	15	888	2,278
6/8/10	22	15	16	940	2,360
6/9/10	17	16	16	1,029	2,377
6/10/10	13	9	10	1,047	1,917
6/11/10	11	6	7	822	1.683

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	MN004	3,801	3,724	3,747	3,821	3,866	3,894	3,886	3,891	3,890	4,148	4,169	4,09[illegible]
Residential w/o Heat	MN003	74	72	71	71	72	74	72	73	73	73	79	7[illegible]
Commercial-SV	MN051/072	301	293	301	296	300	299	305	305	303	312	316	33[illegible]
Commercial-LV	MN073	8	8	8	8	8	8	8	8	8	8	10	[illegible]
Industrial-SV	MN058	0	0	0	0	0	0	0	0	0	0	0	[illegible]
Industrial-LV	MN061	395	382	379	379	382	384	384	384	384	392	416	55[illegible]
SV-Interruptible	MN105/126	19	22	23	23	23	23	23	23	23	23	27	2[illegible]
LV-Interruptible	MN223	0	0	0	0	0	0	0	0	0	0	0	[illegible]
Transport	MN/586/MN70A/76A	5	5	5	5	3	6	5	2	4	5	5	[illegible]
Total		4,603	4,506	4,534	4,603	4,654	4,688	4,683	4,686	4,685	4,961	5,022	5,09[illegible]

MINNESOTA ENERGY RESOURCES - PNG

Projected Fixed Cost - November 2010 through March 2011

Futures Contracts WACOG
VGT

Nov-10 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/18/10	3,846	$ 4.9860	$ 19,177	$ 3.4412	$ 13,235	$ 5,942
06/18/10	513	$ 5.4020	$ 2,770	$ 3.4412	$ 1,765	$ 1,006
06/18/10	3,590	$ 5.4040	$ 19,399	$ 3.4412	$ 12,353	$ 7,046
07/08/10	3,590	$ 4.8260	$ 17,324	$ 3.4412	$ 12,353	$ 4,971
08/05/10	3,077	$ 4.8000	$ 14,769	$ 3.4412	$ 10,588	$ 4,181
09/27/10	2,821	$ 3.8710	$ 10,918	$ 3.4412	$ 9,706	$ 1,212
10/05/10	769	$ 3.7240	$ 2,865	$ 3.4412	$ 2,647	$ 218
10/05/10	1,795	$ 3.7250	$ 6,686	$ 3.4412	$ 6,176	$ 509
Total	20,000		$ 93,908		$ 68,824	$ 25,084
WACOG			$ 4.6954		$ 3.4412	$ 1.2542

Dec-10 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/20/10	500	$ 5.1600	$ 2,580	$ 3.9089	$ 1,954	$ 626
05/20/10	500	$ 5.1610	$ 2,580	$ 3.9089	$ 1,954	$ 626
05/20/10	1,000	$ 5.1620	$ 5,162	$ 3.9089	$ 3,909	$ 1,253
05/20/10	500	$ 5.1630	$ 2,581	$ 3.9089	$ 1,954	$ 627
05/20/10	2,000	$ 5.1640	$ 10,328	$ 3.9089	$ 7,818	$ 2,510
06/29/10	5,500	$ 5.2840	$ 29,062	$ 3.9089	$ 21,499	$ 7,563
07/29/10	3,500	$ 5.1650	$ 18,077	$ 3.9089	$ 13,681	$ 4,396
08/06/10	2,500	$ 4.9940	$ 12,485	$ 3.9089	$ 9,772	$ 2,713
09/14/10	2,000	$ 4.3490	$ 8,698	$ 3.9089	$ 7,818	$ 880
10/07/10	2,000	$ 4.0600	$ 8,120	$ 3.9089	$ 7,818	$ 302
Total	20,000		$ 99,674		$ 78,178	$ 21,497
WACOG			$ 4.9837		$ 3.9089	$ 1.0748

Jan-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/21/10	2,899	$ 5.3350	$ 15,464	$ 4.0860	$ 11,843	$ 3,620
05/21/10	290	$ 5.3370	$ 1,547	$ 4.0860	$ 1,184	$ 363
06/28/10	290	$ 5.6450	$ 1,636	$ 4.0860	$ 1,184	$ 452
06/28/10	1,159	$ 5.6460	$ 6,546	$ 4.0860	$ 4,737	$ 1,809
06/28/10	2,899	$ 5.6490	$ 16,374	$ 4.0860	$ 11,843	$ 4,531
07/29/10	1,739	$ 5.2910	$ 9,202	$ 4.0860	$ 7,106	$ 2,096
07/29/10	290	$ 5.2920	$ 1,534	$ 4.0860	$ 1,184	$ 350
07/29/10	290	$ 5.2930	$ 1,534	$ 4.0860	$ 1,184	$ 350
07/29/10	1,449	$ 5.2940	$ 7,672	$ 4.0860	$ 5,922	$ 1,751
08/10/10	870	$ 4.9870	$ 4,337	$ 4.0860	$ 3,553	$ 784
08/10/10	290	$ 4.9880	$ 1,446	$ 4.0860	$ 1,184	$ 261
08/10/10	580	$ 4.9890	$ 2,892	$ 4.0860	$ 2,369	$ 524
08/10/10	1,449	$ 4.9900	$ 7,232	$ 4.0860	$ 5,922	$ 1,310
09/27/10	2,319	$ 4.3120	$ 9,999	$ 4.0860	$ 9,475	$ 524
09/27/10	580	$ 4.3130	$ 2,500	$ 4.0860	$ 2,369	$ 132
10/07/10	1,449	$ 4.2450	$ 6,152	$ 4.0860	$ 5,922	$ 230
10/07/10	1,159	$ 4.2460	$ 4,923	$ 4.0860	$ 4,737	$ 186
Total	20,000		$ 100,990		$ 81,719	$ 19,271
WACOG			$ 5.0495		$ 4.0860	$ 0.9635

Feb-10 (28)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/24/10	625	$ 5.2550	$ 3,284	$ 4.0812	$ 2,551	$ 734
05/24/10	312	$ 5.2560	$ 1,642	$ 4.0812	$ 1,275	$ 367
05/24/10	1,250	$ 5.2570	$ 6,571	$ 4.0812	$ 5,102	$ 1,470
06/10/10	2,812	$ 5.5990	$ 15,747	$ 4.0812	$ 11,478	$ 4,269
07/29/10	1,875	$ 5.2390	$ 9,823	$ 4.0812	$ 7,652	$ 2,171
08/09/10	1,250	$ 4.9990	$ 6,249	$ 4.0812	$ 5,102	$ 1,147
09/29/10	937	$ 4.3150	$ 4,045	$ 4.0812	$ 3,826	$ 219
10/07/10	937	$ 4.2630	$ 3,997	$ 4.0812	$ 3,826	$ 170
Total	10,000		$ 51,359		$ 40,812	$ 10,547
WACOG			$ 5.1359		$ 4.0812	$ 1.0547

Mar-11 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/14/10	4,149	$ 5.4850	$ 22,757	$ 3.9859	$ 16,537	$ 6,220
05/14/10	957	$ 5.4880	$ 5,254	$ 3.9859	$ 3,816	$ 1,438
06/21/10	6,064	$ 5.5150	$ 33,442	$ 3.9859	$ 24,170	$ 9,272
07/29/10	2,553	$ 5.1410	$ 13,126	$ 3.9859	$ 10,177	$ 2,949
07/29/10	3,191	$ 5.1420	$ 16,411	$ 3.9859	$ 12,721	$ 3,690
08/19/10	638	$ 4.7080	$ 3,005	$ 3.9859	$ 2,544	$ 461
08/19/10	638	$ 4.7090	$ 3,006	$ 3.9859	$ 2,544	$ 462
08/19/10	3,511	$ 4.7100	$ 16,535	$ 3.9859	$ 13,993	$ 2,542
09/27/10	4,149	$ 4.2640	$ 17,691	$ 3.9859	$ 16,537	$ 1,154
10/07/10	3,511	$ 4.2350	$ 14,868	$ 3.9859	$ 13,993	$ 875
10/07/10	638	$ 4.2390	$ 2,706	$ 3.9859	$ 2,544	$ 162
Total	30,000		$ 148,800		$ 119,576	$ 29,224
WACOG			$ 4.9600		$ 3.9859	$ 0.9741

Total

	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
	12,019	$ 5.2637	$ 63,262	$ 3.8375	$ 46,121	$ 17,141
	2,573	$ 5.3621	$ 13,795	$ 3.8852	$ 9,995	$ 3,800
	12,193	$ 5.4300	$ 66,210	$ 3.8314	$ 46,717	$ 19,493
	10,615	$ 5.2120	$ 55,325	$ 3.8342	$ 40,700	$ 14,625
	13,042	$ 5.1913	$ 67,705	$ 3.8815	$ 50,623	$ 17,082
	11,948	$ 4.8909	$ 58,436	$ 3.8464	$ 45,957	$ 12,479
	6,135	$ 4.8130	$ 29,527	$ 3.8930	$ 23,883	$ 5,644
	9,033	$ 4.5652	$ 41,237	$ 3.8694	$ 34,952	$ 6,285
	7,598	$ 4.4828	$ 34,062	$ 3.9847	$ 30,277	$ 3,785
	6,380	$ 4.2826	$ 27,324	$ 3.9754	$ 25,364	$ 1,960
	928	$ 4.4729	$ 4,152	$ 4.0171	$ 3,729	$ 423
	580	$ 4.9890	$ 2,892	$ 4.0860	$ 2,369	$ 524
	1,449	$ 4.9900	$ 7,232	$ 4.0860	$ 5,922	$ 1,310
	2,319	$ 4.3120	$ 9,999	$ 4.0860	$ 9,475	$ 524
	580	$ 4.3130	$ 2,500	$ 4.0860	$ 2,369	$ 132
	1,449	$ 4.2450	$ 6,152	$ 4.0860	$ 5,922	$ 230
	1,159	$ 4.2460	$ 4,923	$ 4.0860	$ 4,737	$ 186
	100,000		$ 494,732		$ 389,109	$ 105,437
			$ 4.9473		$ 3.8911	$ 1.0544

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
Nov-10	494,259	$ 3.6890	$ 1,823,321	94,773	$ 3.7065	$ 351,276
Dec-10	1,241,984	$ 4.0684	$ 5,052,852	260,095	$ 4.1445	$ 1,077,964
Jan-11	1,241,984	$ 4.3351	$ 5,384,181	260,095	$ 4.2080	$ 1,094,480
Feb-11	1,241,984	$ 4.3571	$ 5,411,451	234,925	$ 4.2170	$ 990,679
Mar-11	494,259	$ 4.2157	$ 2,083,645	97,932	$ 4.1795	$ 409,307
Total	4,714,470	$ 4.1904	$ 19,755,450	947,820	$ 4.1397	$ 3,923,705

Total AECO Storage Volumes	Total AECO Storage WACOG	Total AECO Storage Cost	Total AECO Storage Market WACOG	Total AECO Storage Market Cost
94,773	$ 3.7863	$ 358,837	$ 3.7065	$ 351,276
260,095	$ 3.7863	$ 984,793	$ 4.1445	$ 1,077,964
260,095	$ 3.7863	$ 984,793	$ 4.2080	$ 1,094,480
234,925	$ 3.7863	$ 889,492	$ 4.2170	$ 990,679
97,932	$ 3.7863	$ 370,798	$ 4.1795	$ 409,307
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
7														
8														
9														
10														
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
7														
8														
9														
10														
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
7														
8														
9														
10														
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
7														
8														
9														
10														
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