MICHAEL J. AHERN
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November 1, 2012

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 (VGT) System;
Docket No. G011/M-12-___

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, 2012

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

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

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

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 System (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, 2012.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

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

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 (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, 2012.

This filing includes the following attachments:

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

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

1. Summary of Filing

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

2. Service

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

3. General Filing Information

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

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

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

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

C. Date of the Filing and Proposed Effective Date

Date of filing: November 1, 2012
Proposed Effective Date: November 1, 2012

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, 2012

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

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

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

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, 2012.

II. DISCUSSION

A. MERC's PNG-VGT Design Day Requirements

MERC's 2012-2013 PNG-VGT design day requirements increased 173 Mcf (or approximately 2.53 percent) from 6,851 Mcf to 7,024 Mcf.

Table 1: MERC's Proposed Reserve Margins
For the 2012-2013 Heating Season
VGT PNG

	Reserve Margin 2012-2013 Heating Season	Reserve Margin 2011-2012 Heating Season	Change
VGT-PNG	2.92%	3.87%	-0.95%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for PNG-VGT for the 2012-2013 heating season is positive.

For the Demand Entitlement filing effective November 1, 2012, the total Design Day requirement for PNG-VGT is 7,024 Dth as calculated in Attachment 1, page 2 and Attachment 3.

For the Demand Entitlement filing effective November 1, 2012, the total Design Day capacity for PNG-VGT is 7,229 Dth as calculated in Attachment 3.

The difference between the total Design Day requirement and total Design Day capacity results in a 2.92% positive reserve margin.

B. Forecast Methodology for MERC Demand Entitlement Nov. 1, 2012

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
2. NMU - Northern Minnesota Utility

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 the following weather stations:

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

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

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

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

Analytical Approach

Summary

1. Obtain daily weather data for each weather station as shown in Attachment 13
2. Obtain daily total throughput volumes by pipeline
3. Perform total throughput peak day regressions
4. Subtract interruptible, transport, and joint interruptible expected peak day load volumes based on monthly billing data
5. Add back Daily Firm Capacity (DFC) customer selections
6. Apply sales forecast growth rates

Detail

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

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

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

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

The Peak Day Process consisted of:

I. Data Preparation

II. Regression Generation of Net Daily Metered Volumes

III. Volume Risk Adjustments

IV. Adjusting the Regression Results to a Firm peak day estimate

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

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

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

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65
Bemidji	2/1/1996	-34	8	99	107
Cloquet	2/2/1996	-31	7	96	103
Fargo	1/18/1996	-16	34	81	109
International Falls	2/2/1996	-34	8	99	107
Minneapolis	2/2/1996	-25	8	90	97
Rochester	2/2/1996	-27	10	92	101
Worthington	1/18/1996	-8	32	73	96
Ortonville	1/14/2009	-21	11	86	96

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

In 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 demand areas and related weather stations. This was the case for a handful of paper mills, direct-connects, taconites, and off-system end users. The rest of the interruptible, transportation, and joint interruptible data was available based on monthly billing cycle data that introduces billing lag, meter read lag (not all meters were read every month, resulting in billing cycle estimates and reversals), and other potential errors into their volumes.

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

II. The **Regression Generation of Net Daily Metered Volumes** consisted of:

- For each of the Demand Areas (Service Area / Pipeline):
    1. Gather the net daily metered volumes and weather station data including AHDD65[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

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.

shifts. Month indicator variables are used to isolate load that changes based on winter month, such as businesses that are open extra hours in December and resume normal operating hours in January.

4. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
5. Summarize the Baseload and Use/AHDD65 from each regression.
6. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 in 20 years (volume weighted if using more than one weather station in a single Demand Area).

III. Volume Risk Adjustments

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

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

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

In order to determine firm peak day load, volumes contained in the daily pipeline meter readings for interruptible, joint interruptible and transportation customers needed to be isolated and removed. While it would have been ideal to have daily billing data for all customers, most

of the interruptible, transportation, and joint interruptible data was, in most cases, only available from monthly billing records[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 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

[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.

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

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

N. Maximum Daily Quantity (MDQ):

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

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

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

C. Apply Sales Forecast Growth Rates

The throughput volumes used in the data regressions were from the last three winters and needed to be adjusted to properly forecast the next year. The Revenue Forecasting Department provided a growth rate for each demand area, which were then applied to the adjusted regression results.

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

NMU-GLGT = Paper Mills

NMU-VGT = Lamb Weston

PNG-NNG = Taconites / Direct Connects

PNG-NNG = OSEU (End Users)

B. Daily Firm Capacity

PNG-VGT

PNG-GLGT

PNG-NNG

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 768 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 768 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 was not able to purchase firm winter only capacity (November 2012 through March 2013) from VGT so PNG-VGT replaced with a Wadena Call Option on VGT for PNG-VGT and NMU (VGT) customers. All VGT

capacity is allocated between PNG and NMU on a prorated share based on design day numbers, which changed the allocated volumes on the other VGT contracts.

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC has contracted for 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.

D. Financial Option Units and Premiums

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2012 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 $46,103 for the 2012-2013 winter. Please see Attachment 5.

iii. MERC entered into 20 contracts (10,000/contract) or 200,000. Total premium per contract is approximately $.2305. 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 16 futures contracts (10,000/contract) or 160,000,

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

E. Gas Supply.

The PNG-VGT 2012-2013 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 2012 through March 2013 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 $3.3965. Please see Attachment 12, page 1 of 3. MERC is projecting the AECO Storage WACOG for PNG-VGT to be approximately $2.1432. 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 $3.6315, 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 $3.32 for 70% of normal winter volumes assuming that the NYMEX prices are above the average strike price plus the physical index basis spread. If the NYMEX prices are below the average 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, 2012. 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 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.

H. Impacts of Telemetry

Based on the requirement that all interruptible and transportation customers on MERC's system must have telemetry, this has led to some customers switching from interruptible to firm. On PNG-VGT, there have been two (2) customers that switched from interruptible to firm service. The switching occurred between July 23, 2012 and August 23, 2012. Since MERC's peak day analysis is based on December through February volumes for the three previous winters, for the most part, these volumes aren't represented in MERC's design day analysis. MERC projected the impact on firm requirements by projecting peak day volumes for the customers that switched. The projected peak day was calculated by taking actual peak day and dividing the volume by twenty (20). MERC is projecting an increase in design day of 70 Mcf. Assuming the projected peak day is accurate, MERC would still have adequate firm entitlement to meet a peak day.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2012. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2012

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Amber S. Lee hereby certifies that on the 1st day of October, 2012, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of the Petition on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

/s/ Amber S. Lee
Amber S. Lee

Subscribed and sworn to before me
this 1st day of October, 2012.

/s/ Paula Bjorkman
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
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Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Amber	Lee	lee.amber@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

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

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES - PNG
DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2012

VGT

Design Day Requirement		7024
Total Entitlement on Peak Day(excl. Peak Shaving)		7229
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 20)	5287
Firm Annual Throughput - Minnesota		622040.1
No. of Firm Customers		4675
DPS Load Factor Calculation		0.322341

MINNESOTA ENERGY RESOURCES - PNG
MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2012
VGT

Pipeline Group	Nov11-Mar Customer Count	1/20 Design DDD	Regression Factors Intercept	Slope	Regressior Total Footnote 1	Regressior Adjustmen Footnote 2	1/20 Requi Regressior Footnote 3	Nov11-Mar Customer Growth	12 Avg. Total
PEAK									
	4675	108.54	1394	70	8945	1921	7024	0	7024
Total	4675								7024
OFF PEAK									
	4675	57	1394	70	5359	983	4376	0	4376
Total	4675								4376

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, 2012

VGT

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
12/13	4675	7024	1.50246
11/12	4672	6851	1.466396
10/11	4675	7292	1.559786
09/10	4408	6891	1.563294
08/09	4635	7420	1.600863
07/08	4586	8135	1.773877
06/07	4523	8112	1.7935
05/04	4502	7598	1.687694
04/03	4471	7423	1.660255

Attachment 2

MINNESOTA ENERGY RESOURCES - PNG
SUMMER/WINTER USAGE - Mcf
PROJECTED 12 MONTHS ENDING JUNE 2013
VGT

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	120002.1	493299.7	613301.8
SVI	38372.3	157952.4	196324.7
SVJ	1707	7031.3	8738.3
LVI	0	0	0
Total	160081.4	658283.4	818364.8

Source: Calendar data from SUMG MERCFcst201204 (4-26-12).xlsx

Attachment 3

MINNESOTA ENERGY RESOURCES - PNG
ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2012
VGT

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
AF0012	4782	-51	4731
AF0014 (Dec-Feb) *	420	-4	416
AF0016	0	0	0
AF0102	766	-9	757
AF0183	1148	-1148	0
Wadena Delivered GDD Call Opti	0	1325	1325
Heating Season Total	7116	-1212	7229
Non-Heating Season Total	5548	-60	5488
Total Entitlement	7116	-1212	7229
Heating Season Forecasted Design Day	6851	173	7024
Non-Heating Season Forecasted Design Day	4204	172	4376
Heating Season Capacity Surplus/Shortage	265	-60	205
Non-Heating Season Capacity Surplus/Shortage	1344	-232	1112
Reserve Margin	0.03868		0.029186

*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, 2012

All costs in $/MMBtu	Last Base Cost of Gas G007,G01 MR10-978 Feb. 11	Demand Change G011- M-11-XXX Oct .11**	Last Demand Change G011- M-12-XXX Mar. 12^	VGT Most Recent PGA Oct. 12	Current Proposal Effective Nov.1,201	Result of Proposed Change Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service-Residential: Avg. Annual Use:					82 Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost	1.0565	0.8815	0.7951	0.8288	0.7684	-0.27269	-0.03358	-0.07288	-0.0604
Commodity Margin	1.7746	1.7746	1.7746	1.7746	1.7746	0	0	0	0
Total Cost of Gas	8.3383	6.4251	6.0972	5.8563	5.862022	-0.29698	-0.03857	0.000977	0.005722
Avg Annual Cost	683.7406	526.8582	499.9704	480.2166	480.6858	-0.29698	-0.03857	0.000977	0.469227
Effect of proposed commodity change on average annual bills:									5.422027
Effect of proposed demand change on average annual bills:									-4.9528
2) Small Vol. Interruptible: Avg. Annual Use:					3859 Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost									
Commodity Margin	1.1681	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Total Cost of Gas	6.6753	4.9371	4.6956	4.421	4.487122	-0.3278	-0.0444	0.014956	0.066122
Avg Annual Cost	25759.98	19052.27	18120.32	17060.64	17315.8	-0.3278	-0.0444	0.014956	255.1659
Effect of proposed commodity change on average annual bills:									255.1659
Effect of proposed demand change on average annual bills:									0
3) Large Vol. Interruptible: Avg. Annual Use:					89334 Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost									
Commodity Margin	0.3248	0.3248	0.3248	0.3248	0.3248	0	0	0	0
Total Cost of Gas	5.832	4.0938	3.8523	3.5777	3.643822	-0.3752	-0.05412	0.018482	0.066122
Avg Annual Cost	520995.9	365715.5	344141.4	319610.3	325517.2	-0.3752	-0.05412	0.018482	5906.968
Effect of proposed commodity change on average annual bills:									5906.968
Effect of proposed demand change on average annual bills:									0
4) Small Vol. Firm: Avg. Annual Use:					2860 Mcf				
Agg. Annual CD Units:					15				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost	6.6801	3.4671	3.4671	3.4671	3.4671	-0.48098	-1.3E-16	-1.3E-16	0
Commodity Margin	1.1681	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Demand Margin	1.8	1.8	1.8	1.8	1.8	0	0	0	0
Total Cost of Gas	6.6753	4.9371	4.6956	4.421	4.487122	-0.3278	-0.0444	0.014956	0.066122
Total Demand Cost	8.4801	5.2671	5.2671	5.2671	5.2671	-0.37889	-1.7E-16	-1.7E-16	0
Avg Annual Cost	19218.56	14199.11	13508.42	12723.07	12912.18	-0.32814	-0.04414	0.014864	189.1097
Effect of proposed commodity change on average annual bills:									189.1097
Effect of proposed demand change on average annual bills:									0

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-11-793
*As submitted in Docket No. G007,011/MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781
^$/Mcf Demand Cost rate reflects adjustment to Annual Demand Volumes made on March 1, 2012

MINNESOTA ENERGY RESOURCES-PNG
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA)
Viking Current Cost of Gas

II. VIKING GAS TRANSMISSION'S RATES -- CURRENT COST 41214 CURRENT

Commodity From Schedule D	0.32642	/therm

III. ANNUAL SALES --

Total Annual Sales	8444190	therms
Firm Annual Sales (GS-5)	5774653	therms

IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE 41214 CURRENT

		Monthly Entitlement	Months	Rate $/Dth		Contract Cost	$/therm
A. GS-4	FT-A ZONI AF0012	4731	12	3.4671	=	196834.2	0.034086
	FT-A ZONI AF0014	416	3	3.4671	=	4326.941	0.000749
	FT-A ZONI AF0102	757	12	3.4671	=	31495.14	0.005454
	FT-A ZONI AF0183	0	5	3.7671	=	0	0
	Wadena Delivered GL	1325	3	1.199752		4769.013	0.000826
	Balancing / ML0021	2827	12	1	=	33924	0.005875
	Niska Storage	123573	1	0.95482	=	117990	0.020432
	AECO/Emerson Swap	123573	1	0.439999	=	54372	0.009416
	Total Storage Demand					443711.3	0.076838
	GS-4 Firm Annual Sales in therms				5774653		
	Current Demand Cost of Gas $/therm						0.07684
	Current T-17 Commodity Cost of Gas						0.32642
	Call Option Premium				8444190	46292.98	0.005482
	GS-5 Total Current Commodity Cost of Gas $/therm						0.331902
	Current Total Cost of Gas $/therm						0.408742
B. SVI-4	Current Commodity Cost of Gas/CCf						0.331902
C. SJ-4	Current Demand Cost of Gas/CCf						0.34671
	Current Commodity Cost of Gas/CCf						0.331902
D. LVI-4	Current Commodity Cost of Gas/CCf						0.331902

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, 2012

All costs in $/MMBtu	Last Base Cost of Gas G007,G01 MR10-978 Feb. 11	Demand Change G011- M-11-XXX Oct .11**	Last Demand Change G011- M-12-XXX Mar. 12^	VGT Most Recent PGA Oct. 12	Current Proposal Effective Nov.1,201	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:				82	Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost	1.0565	0.8815	0.7951	0.8288	0.469897	-0.55523	-0.40901	-0.43304	-0.3589
Commodity Margin	1.7746	1.7746	1.7746	1.7746	1.7746	0	0	0	0
Total Cost of Gas	8.3383	6.4251	6.0972	5.8563	5.767638	-0.3083	-0.05405	-0.01514	-0.08866
Avg Annual Cost	683.7406	526.8582	499.9704	480.2166	472.9464	-0.3083	-0.05405	-0.01514	-7.27025
Effect of proposed commodity change on average annual bills:									22.15979
Effect of proposed demand change on average annual bills:									-29.43
2) Small Vol. Interruptible: Avg. Annual Use:				3859	Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost									
Commodity Margin	1.1681	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Total Cost of Gas	6.6753	4.9371	4.6956	4.421	4.691241	-0.29722	-0.00093	0.061127	0.270241
Avg Annual Cost	25759.98	19052.27	18120.32	17060.64	18103.5	-0.29722	-0.00093	0.061127	1042.861
Effect of proposed commodity change on average annual bills:									1042.861
Effect of proposed demand change on average annual bills:									0
3) Large Vol. Interruptible: Avg. Annual Use:				89334	Mcf				
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost									
Commodity Margin	0.3248	0.3248	0.3248	0.3248	0.3248	0	0	0	0
Total Cost of Gas	5.832	4.0938	3.8523	3.5777	3.847941	-0.3402	-0.00113	0.075535	0.270241
Avg Annual Cost	520995.9	365715.5	344141.4	319610.3	343752	-0.3402	-0.00113	0.075535	24141.74
Effect of proposed commodity change on average annual bills:									24141.74
Effect of proposed demand change on average annual bills:									0
4) Small Vol. Firm: Avg. Annual Use:				2860	Mcf				
Agg. Annual CD Units:				15					
Commodity Cost	5.5072	3.769	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost	6.6801	3.4671	3.4671	3.4671	3.4671	-0.48098	-1.3E-16	-1.3E-16	0
Commodity Margin	1.1681	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Demand Margin	1.8	1.8	1.8	1.8	1.8	0	0	0	0
Total Cost of Gas	6.6753	4.9371	4.6956	4.421	4.691241	-0.29722	-0.00093	0.061127	0.270241
Total Demand Cost	8.4801	5.2671	5.2671	5.2671	5.2671	-0.37889	-1.7E-16	-1.7E-16	0
Avg Annual Cost	19218.56	14199.11	13508.42	12723.07	13495.96	-0.29776	-0.00092	0.060747	772.8902
Effect of proposed commodity change on average annual bills:									772.8902
Effect of proposed demand change on average annual bills:									0

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-11-793
*As submitted in Docket No. G007,011/MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781
^$/Mcf Demand Cost rate reflects adjustment to Annual Demand Volumes made on March 1, 2012

MINNESOTA ENERGY RESOURCES-PNG
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA)
VGT
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 (41214 CURRENT

Commodity From Schedule D	0.32642	/therm	

III. ANNUAL SALES --

Total Annual Sales	8444190	therms
Firm Annual Sales (GS-5)	5774653	therms

IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE 41214 CURRENT

			Monthly Entitlemen	Months	Rate $/Dth		Contract Cost	$/therm	
A. GS-4	FT-A ZONE	AF0012	4731	12	3.4671	=	196834.2	0.034086	
	FT-A ZONE	AF0014	416	3	3.4671	=	4326.941	0.000749	
	FT-A ZONE	AF0102	757	12	3.4671	=	31495.14	0.005454	
	FT-A ZONE	AF0183	0	5	3.7671	=	0	0	
	Wadena D	ML0021	1325	3	1.199752	=	4769.013	0.000826	
	Balancing Agreement		2827	12	1	=	33924	0.005875	
							271349.3	0.04699	
	Niska Storage		0	1	0.95482	=	0	0	
	AECO/Emerson Swap		0	1	0.439999	=	0	0	
	Total Storage Demand						0	0	
	GS-4 Firm Annual Sales in therms					5774653			
	Current Demand Cost of Gas $/therm							0.04699	0.04699
	Current T-17 Commodity Cost of Gas							0.32642	
	Call Option Premium					8444190	46292.98	0.005482	
	Niska Storage		123573	1	0.95482	=	117990	0.013973	
	AECO/Emerson Swap		123573	1	0.439999	=	54372	0.006439	
	GS-5 Total Current Commodity Cost of Gas $/therm							0.352314	0.352314
	Current Total Cost of Gas $/therm							0.399304	
B. SVI-4	Current Commodity Cost of Gas/CCf							0.352314	
C. SJ-4	Current Demand Cost of Gas/CCf							0.34671	
	Current Commodity Cost of Gas/CCf							0.352314	
D. LVI-4	Current Commodity Cost of Gas/CCf							0.352314	

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 5

MINNESOTA ENERGY RESOURCES - PNG-VGT
Financial Options
Heating Season 2012-2013

[TRADE SECRET DATA BEGINS

Units - Gas Daily Peaker Packages (Physical)

	November Contract Date	Daily Volume	December Contract Date	Daily Volume	January Contract Date	Daily Volume	February Contract Date	Daily Volume	March Contract Date	Daily Volume	Daily Total	Term Total

Premium - Gas Daily Peaker (Monthly Cost)

	November Option Premium	Premium Cost	December Option Premium	Premium Cost	January Option Premium	Premium Cost	February Option Premium	Premium Cost	March Option Premium	Premium Cost	Total Option Premium	Premium Cost

Units - Futures (Daily Volume)

	November Contract Date	Daily Volume	December Contract Date	Daily Volume	January Contract Date	Daily Volume	February Contract Date	Daily Volume	March Contract Date	Daily Volume	Daily Total	Term Total
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
Total		999.9999		967.742		1290.323		1071.429		967.7419	5297.235	160000
		30000		30000		40000		30000		30000		160000

Units - Call Options (Daily Volume)

	November Contract Date	Daily Volume	December Contract Date	Daily Volume	January Contract Date	Daily Volume	February Contract Date	Daily Volume	March Contract Date	Daily Volume	Daily Total	Term Total
1												
2												
3												
4												
5												
6												
7												
Total		1000		1612.903		1612.903		1428.571		967.742	6622.12	200000
		30000		50000		50000		40000		30000		200000

Premium - Call Option (Monthly Cost)

	November Option Premium	Premium Cost	December Option Premium	Premium Cost	January Option Premium	Premium Cost	February Option Premium	Premium Cost	March Option Premium	Premium Cost	Total Option Premium	Premium Cost
1												
2												
3												
4												
5												
6												
7												
Total	0.1659	4975.826	0.191	9550	0.2373	11866.67	0.2807	11229.16	0.2827	8481.207	0.2305	46102.86

Units - Collar Floor (put)
No Puts were purchased.

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 6
VGT

MINNESOTA ENERGY RESOURCES - PNG

2009-10			2010-11		
G011/M-09	Quantity (Mcf)		G011/M-10	Quantity (Mcf)	
FT-A 12 m	6527	2/	FT-A 12 m	6527	
FT-A 3 mo	1098		FT-A 3 mo	1098	
FT-A (5 mo	0	1/	FT-A 5 mo	0	1/
NNG TF 12	1098	1/	FT-A (5 mo	0	1/
TF12 (NNG	432		NNG TF 12	1098	
TF5 (NNG)	105		TF12 (NNG	105	
TFX12 (NN	389		TF5 (NNG)	389	
TFX5 (NNG	172		TFX12 (NN	172	
FT-D 12 m	0		TFX5 (NNG	0	
			FT-D 12 m	0	
			Wadena D	1098	
Total Desig	7625		Total Desig	8723	
Total Viking	7625		Total Viking	8723	
Total Annu	7348		Total Annu	Quantity (Mcf)	
Total Seas	1375		Total Seas	7625	
Percent Se	0.180328		Percent Se	0.874126	

2011-12			2012-13			Change in
G011/M-11	Quantity (Mcf)		G011/M-12	Quantity (Mcf)		Quantity
FT-A 12 m	5548		FT-A 12 m	5488		-60
FT-A 3 mo	420		FT-A 3 mo	416		-4
FT-A 5 mo	1148		FT-A 5 mo	0		-1148
FT-A (5 mo	0	1/	FT-A (5 mo	0	1/	0
NNG TF 12	0	1/	NNG TF 12	0	1/	0
TF12 (NNG	0		TF12 (NNG	0		0
TF5 (NNG)	0		TF5 (NNG)	0		0
TFX12 (NN	0		TFX12 (NN	0		0
TFX5 (NNG	0		TFX5 (NNG	0		0
FT-D 12 m	0		FT-D 12 m	0		0
Wadena D	0		Wadena D	1325		1325
Total Desig	7116		Total Desig	7229		113
Total Viking	7116		Total Viking	7229		113
Total Annu	5548		Total Annu	5488		-60
Total Seas	1568		Total Seas	416		-1152
Percent Se	0.220349		Percent Se	0.057546		-0.1628

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 Se	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand C	1.0565	0.7951	0.8288	0.7684	-0.27269	-0.03358	-0.07288	-0.0604
Commodity	1.7746	1.7746	1.7746	1.7746	0	0	0	0
Total Cost	8.3383	6.0972	5.8563	5.862022	-0.29698	-0.03857	0.000977	0.005722
Average Ai	82	82	82	82				
Average Ai	683.7406	499.9704	480.2166	480.6858	-0.29698	-0.03857	0.000977	0.469227

General Se	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost of Gas								0
Commodity	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Total Cost	6.6753	4.6956	4.421	4.487122	-0.3278	-0.0444	0.014956	0.066122
Average Ai	3859	3859	3859	3859				
Average Ai	25759.98	18120.32	17060.64	17315.8	-0.3278	-0.0444	0.014956	255.1659

Large Volu	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand Cost of Gas								0
Commodity	0.3248	0.3248	0.3248	0.3248	0	0	0	0
Total Cost	5.832	3.8523	3.5777	3.643822	-0.3752	-0.05412	0.018482	0.066122
Average Ai	89334	89334	89334	89334				
Average Ai	520995.9	344141.4	319610.3	325517.2	-0.3752	-0.05412	0.018482	5906.968

Small Volu	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.319022	-0.39733	-0.0591	0.020327	0.066122
Demand C	6.6801	3.4671	3.4671	3.4671	-0.48098	-1.3E-16	-1.3E-16	0
Commodity	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Demand M	1.8	1.8	1.8	1.8	0	0	0	0
Total Comi	6.6753	4.6956	4.421	4.487122	-0.3278	-0.0444	0.014956	0.066122
Total Dema	8.4801	5.2671	5.2671	5.2671	-0.37889	-1.7E-16	-1.7E-16	0
Total Reco	15.1554	9.9627	9.6881	9.754222	-0.35639	-0.02093	0.006825	0.066122
Average Ai	2860	2860	2860	2860				
Average Ai	15	15	15	15				
Average Ai	19218.56	13508.42	12723.07	12912.18	-0.32814	-0.04414	0.014864	189.1097

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Se	0.066122	0.066122	-0.0604	-0.07288	0.005722	0.000977	0.469227
Small Volu	0.066122	0.066122	0	0	0.066122	0.014956	255.1659
Large Volu	0.066122	0.066122	0	0	-0.06612	0.018482	5906.968
Small Volu	0.066122	0.066122	0	-1.7E-16	0	0	189.1097

* Average Annual Bill amount does not include customer charges.
^$/Mcf Demand Cost rate reflects adjustment to Annual Demand Volumes made on March 1, 2012

MINNESOTA ENERGY RESOURCES - PNG

General Se	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand C	1.0565	0.7951	0.8288	0.469897	-0.55523	-0.40901	-0.43304	-0.3589
Commodity	1.7746	1.7746	1.7746	1.7746	0	0	0	0
Total Cost	8.3383	6.0972	5.8563	5.767638	-0.3083	-0.05405	-0.01514	-0.08866
Average Ai	82	82	82	82				
Average Ai	683.7406	499.9704	480.2166	472.9464	-0.3083	-0.05405	-0.01514	-7.27025

General Se	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost of Gas								0
Commodity	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Total Cost	6.6753	4.6956	4.421	4.691241	-0.29722	-0.00093	0.061127	0.270241
Average Ai	3859	3859	3859	3859				
Average Ai	25759.98	18120.32	17060.64	18103.5	-0.29722	-0.00093	0.061127	1042.861

Large Volu	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand Cost of Gas								0
Commodity	0.3248	0.3248	0.3248	0.3248	0	0	0	0
Total Cost	5.832	3.8523	3.5777	3.847941	-0.3402	-0.00113	0.075535	0.270241
Average Ai	89334	89334	89334	89334				
Average Ai	520995.9	344141.4	319610.3	343752	-0.3402	-0.00113	0.075535	24141.74

Small Volu	Base Cost Change G011/MR1	Last Dema Change Mar. 12^	Most Rece PGA Oct. 12	Nov 1/12 P w/ Propose Demand C	% Change From Last Rate Case	% Change From Last Demand Fi	% Change From Last PGA	$ Change From Last PGA
Commodity	5.5072	3.5275	3.2529	3.523141	-0.36027	-0.00124	0.083077	0.270241
Demand C	6.6801	3.4671	3.4671	3.4671	-0.48098	-1.3E-16	-1.3E-16	0
Commodity	1.1681	1.1681	1.1681	1.1681	0	0	0	0
Demand M	1.8	1.8	1.8	1.8	0	0	0	0
Total Comi	6.6753	4.6956	4.421	4.691241	-0.29722	-0.00093	0.061127	0.270241
Total Dema	8.4801	5.2671	5.2671	5.2671	-0.37889	-1.7E-16	-1.7E-16	0
Total Reco	15.1554	9.9627	9.6881	9.958341	-0.34292	-0.00044	0.027894	0.270241
Average Ai	2860	2860	2860	2860				
Average Ai	15	15	15	15				
Average Ai	19218.56	13508.42	12723.07	13495.96	-0.29776	-0.00092	0.060747	772.8902

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Se	0.270241	0.270241	-0.3589	-0.43304	-0.08866	-0.01514	-7.27025
Small Volu	0.270241	0.270241	0	0	0.270241	0.061127	1042.861
Large Volu	0.270241	0.270241	0	0	-0.27024	0.075535	24141.74
Small Volu	0.270241	0.270241	0	-1.7E-16	0	0	772.8902

* Average Annual Bill amount does not include customer charges.
^$/Mcf Demand Cost rate reflects adjustment to Annual Demand Volumes made on March 1, 2012

Atttachment 8
VGT

MINNESOTA ENERGY RESOURCES - PNG

	41183 Entitlement	41214 Entitlement	Entitlement Change	Months	Oct. 2012 Tariff Rate	Oct. 2012 Total Cost	Nov. 2012 Total Cost	Entitlement Change
FT-A (AF0	4782	4731	-51	12	3.4671	198956.1	196834.2	-2121.87
FT-A (AF0	420	416	-4	3	3.4671	4368.546	4326.941	-41.6052
FT-A (AF0	0	0	0	12	3.4671	0	0	0
FT-A (AF0	766	757	-9	12	3.4671	31869.58	31495.14	-374.447
FT-A (AF0	1148	0	-1148	5	3.7671	21623.15	0	-21623.2
Balancing /	2858	2827	-31	12	1	34296	33924	-372
Wadena D	0	1325	1325	3	1.199752	0	4769.013	4769.013
Niska Stor	134401	123573	-10828	1	0.95482	128328.8	117990	-10338.8
AECO/Em	134401	123573	-10828	1	0.439999	59137.31	54372	-4765.31
Total Demand Cost						478579.4	443711.3	-34868.1

MINNESOTA ENERGY RESOURCES - PNG
12/13 Winter Portfolio Plan - MERC VGT-PNG Hedging Plan
[TRADE SECRET DATA BEGINS]

[TRADE SECRET DATA ENDS

MINNESOTA ENERGY RESOURCES
VGT WINTER PLAN (PNG)
NOVEMBER, 2012 THROUGH MARCH, 2013
[TRADE SECRET DATA BEGINS

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

123572.9

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, 2011 through June 30, 2012

			Base	1398
			Variable	70
Date	1 Fargo Adjusted HDD	1 Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put
40725	0	0	701	1398
40726	0	0	592	1398
40727	0	0	477	1398
40728	0	0	533	1398
40729	0	0	823	1398
40730	0	0	793	1398
40731	0	0	798	1398
40732	0	0	684	1398
40733	0	0	596	1398
40734	0	0	575	1398
40735	0	0	884	1398
40736	0	0	857	1398
40737	0	0	868	1398
40738	0	0	847	1398
40739	0	0	694	1398
40740	0	0	573	1398
40741	0	0	550	1398
40742	0	0	783	1398
40743	0	0	750	1398
40744	0	0	753	1398
40745	0	0	801	1398
40746	0	0	657	1398
40747	0	0	587	1398
40748	0	0	579	1398
40749	0	0	778	1398
40750	0	0	746	1398
40751	0	0	788	1398
40752	0	0	811	1398
40753	0	0	669	1398
40754	0	0	601	1398
40755	0	0	535	1398
40756	0	0	785	1398
40757	0	0	800	1398
40758	0	0	802	1398
40759	0	0	827	1398
40760	0	0	707	1398
40761	0	0	636	1398
40762	0	0	606	1398
40763	0	0	806	1398

40764	0	0	857	1398
40765	0	0	815	1398
40766	0	0	844	1398
40767	0	0	728	1398
40768	0	0	615	1398
40769	0	0	576	1398
40770	0	0	783	1398
40771	0	0	839	1398
40772	0	0	795	1398
40773	0	0	804	1398
40774	0	0	762	1398
40775	0	0	653	1398
40776	0	0	603	1398
40777	0	0	769	1398
40778	0	0	768	1398
40779	0	0	847	1398
40780	0	0	834	1398
40781	0	0	737	1398
40782	0	0	615	1398
40783	0	0	611	1398
40784	0	0	865	1398
40785	0	0	825	1398
40786	0	0	800	1398
40787	0	0	792	1398
40788	0	0	754	1398
40789	5.75	5.75	717	1800.5
40790	7.42	7.42	651	1917.4
40791	0	0	654	1398
40792	0	0	877	1398
40793	0	0	850	1398
40794	0	0	842	1398
40795	0	0	758	1398
40796	0	0	635	1398
40797	0	0	626	1398
40798	2.26	2.26	901	1556.2
40799	13.68	13.68	1140	2355.6
40800	22.89	22.89	1652	3000.3
40801	17.12	17.12	1407	2596.4
40802	12.54	12.54	1374	2275.8
40803	6.9	6.9	1070	1881
40804	6.42	6.42	1000	1847.4
40805	0	0	988	1398
40806	12.98	12.98	1296	2306.6
40807	23.94	23.94	1660	3073.8
40808	16.8	16.8	1687	2574
40809	8.88	8.88	1298	2019.6
40810	5.5	5.5	1065	1783
40811	9.72	9.72	1027	2078.4
40812	6.12	6.12	1137	1826.4
40813	0	0	1090	1398
40814	0	0	1045	1398
40815	15.08	15.08	1375	2453.6

40816	15.26	15.26	1353	2466.2
40817	5.85	5.85	1088	1807.5
40818	0	0	816	1398
40819	0	0	1006	1398
40820	0	0	951	1398
40821	0	0	964	1398
40822	0	0	958	1398
40823	0	0	910	1398
40824	8.64	8.64	848	2002.8
40825	7.7	7.7	863	1937
40826	9.81	9.81	1214	2084.7
40827	2.22	2.22	1159	1553.4
40828	6.66	6.66	1322	1864.2
40829	15.54	15.54	1621	2485.8
40830	21.66	21.66	1877	2914.2
40831	18.08	18.08	1693	2663.6
40832	23.6	23.6	1884	3050
40833	23.2	23.2	2254	3022
40834	29.64	29.64	2713	3472.8
40835	32.1	32.1	2794	3645
40836	27.3	27.3	2423	3309
40837	20.14	20.14	2023	2807.8
40838	15.4	15.4	1601	2476
40839	17.12	17.12	1886	2596.4
40840	18.9	18.9	2038	2721
40841	20.8	20.8	2267	2854
40842	28.62	28.62	2499	3401.4
40843	28.08	28.08	2684	3363.6
40844	28.08	28.08	2566	3363.6
40845	27.75	27.75	2231	3340.5
40846	30.52	30.52	2480	3534.4
40847	20.34	20.34	2322	2821.8
40848	25.53	25.53	2604	3185.1
40849	30.24	30.24	3094	3514.8
40850	27.6	27.6	2775	3330
40851	21.25	21.25	2426	2885.5
40852	18.3	18.3	1900	2679
40853	31.2	31.2	2804	3582
40854	33.79	33.79	3322	3763.3
40855	31.61	31.61	3190	3610.7
40856	36.58	36.58	3606	3958.6
40857	35.84	35.84	3505	3906.8
40858	23.76	23.76	2709	3061.2
40859	21.8	21.8	2306	2924
40860	30.52	30.52	3040	3534.4
40861	35.64	35.64	3321	3892.8
40862	42.12	42.12	4063	4346.4
40863	54.88	54.88	4932	5239.6
40864	49.22	49.22	4411	4843.4
40865	44.69	44.69	4150	4526.3
40866	64.4	64.4	5113	5906
40867	58.86	58.86	4826	5518.2

40868	45.51	45.51	4035	4583.7
40869	33.6	33.6	3668	3750
40870	28	28	2923	3358
40871	24.61	24.61	2638	3120.7
40872	30.51	30.51	2774	3533.7
40873	42.48	42.48	3572	4371.6
40874	42.9	42.9	3844	4401
40875	36.3	36.3	3871	3939
40876	42.12	42.12	3912	4346.4
40877	45.6	45.6	4095	4590
40878	51.98	51.98	4897	5036.6
40879	38.61	38.61	4012	4100.7
40880	42.51	42.51	4098	4373.7
40881	57.72	57.72	4760	5438.4
40882	61.04	61.04	5973	5670.8
40883	52.2	52.2	5012	5052
40884	46.33	46.33	4590	4641.1
40885	62.15	62.15	5859	5748.5
40886	59.4	59.4	5511	5556
40887	38.85	38.85	3770	4117.5
40888	37.4	37.4	3497	4016
40889	44.69	44.69	4061	4526.3
40890	37.08	37.08	3564	3993.6
40891	36.63	36.63	3739	3962.1
40892	46.87	46.87	5067	4678.9
40893	50.29	50.29	4605	4918.3
40894	39.6	39.6	3882	4170
40895	29.38	29.38	3414	3454.6
40896	44.69	44.69	4619	4526.3
40897	37.74	37.74	3922	4039.8
40898	42.18	42.18	4146	4350.6
40899	43.29	43.29	4253	4428.3
40900	45.1	45.1	4368	4555
40901	39.9	39.9	3496	4191
40902	32.77	32.77	3197	3691.9
40903	40.8	40.8	3458	4254
40904	55.59	55.59	4705	5289.3
40905	39.24	39.24	3714	4144.8
40906	42	42	3814	4338
40907	38.88	38.88	3645	4119.6
40908	39.9	39.9	3661	4191
40909	59	59	4935	5528
40910	62.16	62.16	5382	5749.2
40911	42.56	42.56	4662	4377.2
40912	34.24	34.24	3960	3794.8
40913	24.64	24.64	3111	3122.8
40914	35.03	35.03	3472	3850.1
40915	39.22	39.22	3498	4143.4
40916	38.42	38.42	3322	4087.4
40917	26.16	26.16	3523	3229.2
40918	32.19	32.19	3420	3651.3
40919	62.4	62.4	6179	5766

40920	72.32	72.32	6901	6460.4
40921	62.64	62.64	5671	5782.8
40922	42.12	42.12	4398	4346.4
40923	47.56	47.56	4255	4727.2
40924	71.92	71.92	6442	6432.4
40925	70.62	70.62	7144	6341.4
40926	77.97	77.97	7798	6855.9
40927	75.6	75.6	7541	6690
40928	62.4	62.4	6720	5766
40929	58.8	58.8	5569	5514
40930	46.2	46.2	4544	4632
40931	61.6	61.6	5501	5710
40932	52.17	52.17	4782	5049.9
40933	39.44	39.44	4476	4158.8
40934	39.96	39.96	4297	4195.2
40935	48.72	48.72	4531	4808.4
40936	58.86	58.86	4910	5518.2
40937	61.6	61.6	5156	5710
40938	36.72	36.72	4148	3968.4
40939	41.04	41.04	4225	4270.8
40940	38.85	38.85	3882	4117.5
40941	39.78	39.78	3909	4182.6
40942	40.17	40.17	3965	4209.9
40943	41.34	41.34	3783	4291.8
40944	38.15	38.15	3793	4068.5
40945	57.12	57.12	4746	5396.4
40946	56.18	56.18	5730	5330.6
40947	49.5	49.5	5098	4863
40948	61.88	61.88	5970	5729.6
40949	73.26	73.26	7139	6526.2
40950	62.64	62.64	6164	5782.8
40951	52.8	52.8	4904	5094
40952	42.12	42.12	4874	4346.4
40953	38.48	38.48	4113	4091.6
40954	39.59	39.59	4225	4169.3
40955	38.5	38.5	4006	4093
40956	45.36	45.36	4422	4573.2
40957	39.96	39.96	3895	4195.2
40958	31.32	31.32	3263	3590.4
40959	35.97	35.97	3915	3915.9
40960	48.84	48.84	4417	4816.8
40961	48.88	48.88	4509	4819.6
40962	45.36	45.36	4340	4573.2
40963	62.16	62.16	5488	5749.2
40964	55.5	55.5	4608	5283
40965	58.5	58.5	4694	5493
40966	54.57	54.57	5009	5217.9
40967	41.4	41.4	4368	4296
40968	41.07	41.07	3980	4272.9
40969	41.07	41.07	4031	4272.9
40970	53.82	53.82	4741	5165.4
40971	62.06	62.06	5312	5742.2

40972	55.12	55.12	4768	5256.4
40973	41.76	41.76	4197	4321.2
40974	38.28	38.28	3427	4077.6
40975	49.02	49.02	4988	4829.4
40976	50.4	50.4	5277	4926
40977	43.29	43.29	4643	4428.3
40978	27	27	2700	3288
40979	16.1	16.1	2116	2525
40980	23.98	23.98	3110	3076.6
40981	12.98	12.98	2239	2306.6
40982	22.47	22.47	2398	2970.9
40983	14.98	14.98	2484	2446.6
40984	2.3	2.3	1361	1559
40985	0	0	1062	1398
40986	0	0	1034	1398
40987	6.78	6.78	1361	1872.6
40988	16.96	16.96	1983	2585.2
40989	11.44	11.44	1787	2198.8
40990	4.28	4.28	1535	1697.6
40991	8.4	8.4	1287	1986
40992	26.68	26.68	2074	3265.6
40993	27.84	27.84	2428	3346.8
40994	18.9	18.9	3167	2721
40995	26.91	26.91	2794	3281.7
40996	27.5	27.5	3099	3323
40997	28.62	28.62	3164	3401.4
40998	14.69	14.69	2055	2426.3
40999	5.45	5.45	1661	1779.5
41000	2.26	2.26	1347	1556.2
41001	20.52	20.52	2152	2834.4
41002	19.08	19.08	2122	2733.6
41003	12.21	12.21	1950	2252.7
41004	11.9	11.9	2080	2231
41005	21.78	21.78	1657	2922.6
41006	23.2	23.2	2153	3022
41007	34.2	34.2	2265	3792
41008	37.74	37.74	3776	4039.8
41009	34.32	34.32	3661	3800.4
41010	16.95	16.95	2931	2584.5
41011	15.96	15.96	1926	2515.2
41012	9.63	9.63	2223	2072.1
41013	22.14	22.14	1230	2947.8
41014	33.04	33.04	2753	3710.8
41015	24.64	24.64	3347	3122.8
41016	18.87	18.87	2173	2718.9
41017	20.33	20.33	2499	2821.1
41018	21.2	21.2	2286	2882
41019	19.89	19.89	1912	2790.3
41020	17.44	17.44	2344	2618.8
41021	9.81	9.81	1974	2084.7
41022	4.44	4.44	1586	1708.8
41023	6.96	6.96	1305	1885.2

41024	21.47	21.47	1558	2900.9
41025	19.04	19.04	2042	2730.8
41026	21.66	21.66	2267	2914.2
41027	16.38	16.38	2184	2544.6
41028	7.63	7.63	1688	1932.1
41029	1.1	1.1	1469	1475
41030	3.24	3.24	1414	1624.8
41031	5.55	5.55	1176	1786.5
41032	8.8	8.8	1220	2014
41033	4.32	4.32	1451	1700.4
41034	2.18	2.18	1173	1550.6
41035	10.53	10.53	1221	2135.1
41036	14.82	14.82	1610	2435.4
41037	12.84	12.84	1801	2296.8
41038	0	0	1425	1398
41039	10.53	10.53	1211	2135.1
41040	9.81	9.81	1476	2084.7
41041	0	0	1025	1398
41042	0	0	888	1398
41043	6.96	6.96	1043	1885.2
41044	7.7	7.7	1291	1937
41045	0	0	1089	1398
41046	0	0	1006	1398
41047	4.6	4.6	796	1720
41048	6.54	6.54	900	1855.8
41049	1.12	1.12	946	1476.4
41050	0	0	1007	1398
41051	3.27	3.27	958	1626.9
41052	6.6	6.6	1076	1860
41053	13.32	13.32	1191	2330.4
41054	9.2	9.2	1041	2042
41055	0	0	949	1398
41056	7.84	7.84	664	1946.8
41057	18.4	18.4	876	2686
41058	16.64	16.64	1585	2562.8
41059	8.4	8.4	1371	1986
41060	5.4	5.4	1167	1776
41061	0	0	956	1398
41062	0	0	757	1398
41063	0	0	735	1398
41064	0	0	966	1398
41065	0	0	902	1398
41066	0	0	905	1398
41067	0	0	882	1398
41068	0	0	780	1398
41069	0	0	670	1398
41070	10.71	10.71	768	2147.7
41071	8.64	8.64	1237	2002.8
41072	0	0	1099	1398
41073	0	0	1046	1398
41074	0	0	968	1398
41075	0	0	794	1398

41076	0	0	740	1398
41077	0	0	719	1398
41078	1.11	1.11	945	1475.7
41079	0	0	1010	1398
41080	0	0	1014	1398
41081	0	0	929	1398
41082	0	0	764	1398
41083	0	0	661	1398
41084	0	0	692	1398
41085	0	0	901	1398
41086	0	0	858	1398
41087	0	0	899	1398
41088	0	0	850	1398
41089	0	0	693	1398
41090	0	0	637	1398
Totals	7668.75	7668.75	868060	1048481

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

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

Attachment 11
VGT

MINNESOTA ENERGY RESOURCES - PNG
Customer Counts by PGAC Class - July 1, 2011 through June 30, 2012

Rate Class	Tariff Rate Designatio	40725 Average Customers	40757 Average Customers	40789 Average Customers	40821 Average Customers	40853 Average Customers	40885 Average Customers	40917 Average Customers	40949 Average Customers	40982 Average Customers	41014 Average Customers	41046 Average Customers	41078 Average Customers
Residentia	MN004	3762	3733	3753	3791	3828	3882	3920	3906	3929	3915	3925	3877
Residentia	MN003	71	69	69	70	70	72	71	72	71	72	71	68
Commercia	MN051/07	323	316	317	319	321	331	337	338	335	342	379	376
Commercia	MN073	10	9	9	10	10	10	10	10	10	10	9	9
Industrial-S	MN758	0	0	0	0	0	1	0	1	1	1	1	1
Industrial-L	MN061	366	364	363	363	368	365	366	367	371	369	328	328
SV-Interrup	MN705/12(	18	17	16	15	16	18	18	14	18	18	18	18
LV-Interrup	MN723	1	1	1	1	1	1	1	1	1	1	1	1
Transport	MN786/70/	5	5	5	5	3	2	5	5	5	5	5	5
Total		4556	4514	4533	4574	4617	4682	4728	4714	4741	4733	4737	4683

MINNESOTA ENERGY RESOURCES - PNG
Projected Fixed Cost - November 2012 through March 2013

Futures Contracts WACOG

VGT							30								31							31
	41223							41249								41280						
Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Und Market		Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Und Market		Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
41054	4239.129	2.996	12700.43	3.776	16006.95	-3306.52		41058	5915.494	3.176	18787.61	4.088	24182.54	-5394.93		41059	824.7426	3.264	2691.96	4.1895	3455.259	-763.299
41054	1630.434	2.997	4886.411	3.776	6156.519	-1270.11		41089	4225.353	3.329	14066.2	4.088	17273.24	-3207.04		05/3012/	1649.485	3.265	5385.569	4.1895	6910.518	-1524.95
41088	5869.566	3.017	17708.48	3.776	22163.48	-4455		41089	1690.142	3.331	5629.862	4.088	6909.299	-1279.44		0530/12	5360.824	3.266	17508.45	4.1895	22459.17	-4950.72
41121	4891.305	3.313	16204.89	3.776	18469.57	-2264.67		41120	5915.494	3.6	21295.78	4.088	24182.54	-2886.76		41088	824.7426	3.425	2824.743	4.1895	3455.259	-630.516
41121	652.173	3.314	2161.301	3.776	2462.605	-301.304		41143	4647.886	3.288	15282.25	4.088	19000.56	-3718.31		41088	3298.97	3.427	11305.57	4.1895	13821.04	-2515.46
41136	4565.217	2.988	13640.87	3.776	17238.26	-3597.39		41172	4225.353	3.248	13723.95	4.088	17273.24	-3549.3		41088	3298.97	3.428	11308.87	4.1895	13821.04	-2512.17
41173	4239.129	3.065	12992.93	3.776	16006.95	-3014.02		41205	3380.28	3.863	13058.02	4.088	13818.59	-760.563		41117	7010.309	3.573	25047.83	4.1895	29369.69	-4321.86
41190	3913.044	3.408	13335.65	3.776	14775.65	-1440										41144	6597.938	3.426	22604.53	4.1895	27642.06	-5037.53
																41171	5773.195	3.39	19571.13	4.1895	24186.8	-4615.67
																41207	5360.824	3.904	20928.66	4.1895	22459.17	-1530.52
Total	30000		93630.97		113280	-19649		30000			101843.7		122640	-20796.3		40000			139177.3		167580	-28402.7
WACOG			3.121033		3.776	-0.65497					3.394789		4.088	-0.69321					3.479433		4.1895	-0.71007

						28							31								
	41316						41339							Total							
Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Und Market	Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market		Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
41058	6600	3.34	22044	4.1825	27604.5	-5560.5	41059	2608.697	3.258	8499.133	4.0675	10610.87	-2111.74		20188.06	3.20601	64723.14	4.054878	81860.13	-17137
41089	600.0008	3.484	2090.403	4.1825	2509.503	-419.101	41059	3260.868	3.26	10630.43	4.0675	13263.58	-2633.15		11366.14	3.260474	37059.01	4.057082	46113.36	-9054.35
41089	6000	3.485	20910	4.1825	25095	-4185	41087	5869.565	3.461	20314.56	4.0675	23874.45	-3559.89		24790.1	3.310651	82071.36	4.054095	100501.4	-18430
41109	600.0008	3.526	2115.603	4.1825	2509.503	-393.901	41116	5543.479	3.612	20023.05	4.0675	22548.1	-2525.05		17775.02	3.514148	62464.07	4.00365	71164.97	-8700.91
41109	6000	3.528	21168	4.1825	25095	-3927	41145	4891.304	3.362	16444.56	4.0675	19895.38	-3450.81		19490.33	3.404851	66361.68	4.118687	80274.58	-13912.9
41138	600.0008	3.405	2043.003	4.1825	2509.503	-466.501	41170	4239.129	3.416	14480.87	4.0675	17242.66	-2761.79		16928.67	3.260596	55197.55	4.021858	68084.7	-12887.1
41138	4200	3.406	14305.2	4.1825	17566.5	-3261.3	41207	3586.957	3.882	13924.57	4.0675	14589.95	-665.381		22416.68	3.538819	79328.56	4.075166	91351.68	-12023.1
41169	3000.001	3.46	10380	4.1825	12547.51	-2167.5									13510.98	3.428336	46320.19	4.068188	54965.22	-8645.03
41204	2400	3.926	9422.402	4.1825	10038	-615.6									8173.196	3.547393	28993.53	4.187445	34224.8	-5231.27
															5360.824	3.904	20928.66	4.1895	22459.17	-1530.52
Total	30000		104478.6		125475	-20996.4		30000		104317.2		122025	-17707.8		160000		543447.7		651000	-107552
WACOG			3.48262		4.1825	-0.69988				3.477239		4.0675	-0.59026				3.396548		4.06875	-0.6722

MINNESOTA ENERGY RESOURCES - PNG
Projected Storage Cost - November 2012 through March 2013

Month/ Year	K#118657 NNG Storage	Storage K#123780 LS Power	Storage K#123781 LS Power	Total NNG Storage	WACOG Projected K#118657 NNG WACOG	Projected K#123780 NNG WACOG	Projected K#123781 NNG WACOG	K#118657 NNG Storage Cost	K#123780 NNG Storage Cost	K#123781 NNG Storage Cost	Total NNG Storage Cost	GLGT/VGT Centra AECO Sto	GLGT/VGT Centra AECO Sto WACOG	GLGT/VGT Centra AECO Storage Cost
41219	455259	65027.38	17340.64	537627	2.8422	2.8422	2.8422	1293937	184820.8	49285.56	1528044	85304	2.1432	182823.5
41250	1143984	163402.1	43573.91	1350960	2.8422	2.8422	2.8422	3251431	464421.6	123845.8	3839699	229242	2.1432	491311.5
41282	1143984	163402.1	43573.91	1350960	2.8422	2.8422	2.8422	3251431	464421.6	123845.8	3839699	229242	2.1432	491311.5
41314	1017303	163402.1	43573.91	1224279	2.8422	2.8422	2.8422	2891379	464421.6	123845.8	3479646	214452	2.1432	459613.5
41343	455259	65027.38	17340.64	537627	2.8422	2.8422	2.8422	1293937	184820.8	49285.56	1528044	96345	2.1432	206486.6
Total	4215789	620261.2	165403	5001453	2.8422	2.8422	85.9424	11982116	1762906	470108.4	14215130	854585	2.1432	1831547
										2.8422			2.1432	

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson Indexes Price	Emerson Indexes Cost	Total AECO Sto Volumes	Total AECO Sto WACOG	Total AECO Sto Cost	Total Emerson WACOG	Total Emerson Cost
41219	537627	3.72	1999973	85304	3.75	319890	85304	2.1432	182823.5	3.75	319890
41250	1350960	4.011	5418701	229242	4.0885	937255.9	229242	2.1432	491311.5	4.0885	937255.9
41282	1350960	4.1055	5546366	229242	4.203	963504.1	229242	2.1432	491311.5	4.203	963504.1
41314	1224279	4.109	5030563	214452	4.189	898339.4	214452	2.1432	459613.5	4.189	898339.4
41343	537627	4.0345	2169056	96345	4.0695	392076	96345	2.1432	206486.6	4.0695	392076
Total	5001453	4.03176	20164659	854585	4.108503	3511065	854585	2.1432	1831547	4.108503	3511065

Max NNG Storage (Storage plan withdrawals through Ap	5001453	5619321	10/31/11 Storage Balance - NNG	5619321	1 5001453
Max AECO Storage	854585		10/31/11 Storage Balance - AEC	947820	

Month/ Year	K#118657 NNG Storage	Storage K#123780 LS Power	Storage K#123781 LS Power	Total NNG Storage	NNG PNG Volumes	NNG NMU Volumes	NNG Total Volumes	Projected K#118657 NNG WACOG	Projected K#123780 NNG WACOG	Projected K#123781 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
41219	455259	65027.38	17340.64	537627	478092	59535	537627	2.8422	2.8422	2.8422	1358833	169210.4	1528044	3.72	1778502	221470.2	1999973
41250	1143984	163402.1	43573.91	1350960	1201359	149600.8	1350960	2.8422	2.8422	2.8422	3414503	425195.3	3839699	4.011	4816652	600048.6	5418701
41282	1143984	163402.1	43573.91	1350960	1201359	149600.8	1350960	2.8422	2.8422	2.8422	3414503	425195.3	3839699	4.1055	4932181	614185.9	5546366
41314	1017303	163402.1	43573.91	1224279	1088707	135572.5	1224279	2.8422	2.8422	2.8422	3094322	385324.3	3479646	4.109	4473495	557067.5	5030563
41343	455259	65027.38	17340.64	537627	478092	59535	537627	2.8422	2.8422	2.8422	1358833	169210.4	1528044	4.0345	1928862	240194	2169056
Total	4215789	620261.2	165403	5001453	4447609	553844	5001453	2.8422	2.8422	2.8422	12640995	1574136	14215130	4.03176	17931693	2232966	20164659
											2.8422	2.8422		4.03176	4.03176	4.03176	

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total AECO Sto Volumes	GLGT/VGT Centra AECO Sto WACOG	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Storage Cost
41219	85304	12351.49	24049.04	12434.87	19722.89	16745.71	85304	2.1432	26471.72	51541.9	26650.42	42270.09	35889.41	182823.5
41250	229242	33192.83	64628.27	33416.9	53002.37	45001.64	229242	2.1432	71138.87	138511.3	71619.09	113594.7	96447.52	491311.5
41282	229242	33192.83	64628.27	33416.9	53002.37	45001.64	229242	2.1432	71138.87	138511.3	71619.09	113594.7	96447.52	491311.5
41314	214452	31051.33	60458.65	31260.94	49582.81	42098.27	214452	2.1432	66549.2	129575	66998.45	106265.9	90225.02	459613.5
41343	96345	13950.16	27161.74	14044.33	22275.64	18913.13	96345	2.1432	29897.99	58213.03	30099.81	47741.16	40534.61	206486.6
Total	854585	123738.6	240926	124573.9	197586.1	167760.4	854585	2.1432	265196.6	516352.5	266986.9	423466.5	359544.1	1831547
		0.144794	0.281922	0.145771	0.231207	0.196306	1		2.1432	2.1432	2.1432	2.1432	2.1432	2.1432

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total AECO Storage Volumes	Projected Emerson Index Price	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Cost
41219	85304	12351.49	24049.04	12434.87	19722.89	16745.71	85304	3.75	46318.1	90183.9	46630.77	73960.82	62796.41	319890
41250	229242	33192.83	64628.27	33416.9	53002.37	45001.64	229242	4.0885	135708.9	264232.7	136625	216700.2	183989.2	937255.9
41282	229242	33192.83	64628.27	33416.9	53002.37	45001.64	229242	4.203	139509.4	271632.6	140451.2	222768.9	189141.9	963504.1
41314	214452	31051.33	60458.65	31260.94	49582.81	42098.27	214452	4.189	130074	253261.3	130952.1	207702.4	176349.7	898339.4
41343	96345	13950.16	27161.74	14044.33	22275.64	18913.13	96345	4.0695	56770.18	110534.7	57153.41	90650.73	76966.97	392076
Total	854585	123738.6	240926	124573.9	197586.1	167760.4	854585	4.108503	508380.6	989845.2	511812.5	811783.1	689244.2	3511065
		0.144794	0.281922	0.145771	0.231207	0.196306	1		4.108503	4.108503	4.108503	4.108503	4.108503	4.108503

MINNESOTA ENERGY RESOURCES - PNG
Protected Call Option Costs - November 2012 through March 2013

Call/Put Options WACOG

Contract = 10000

Call/Put Options

41219

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41060		16	160000	3	480000	3	480000	3.4	544000	-64000	0.267	42720	522720
2	41085		17	170000	3.25	552500	3.25	552500	3.4	578000	-25500	0.248	42160	594660
3	41114		19	190000	3.5	665000	3.4	646000	3.4	646000	0	0.209	39710	685710
4	41148		21	210000	3	630000	3	630000	3.4	714000	-84000	0.177	37170	667170
5	41180		21	210000	3.5	735000	3.4	714000	3.4	714000	0	0.068	14280	728280
6	41197		21	210000	3.5	735000	3.4	714000	3.4	714000	0	0.07	14700	728700
7			0	0	0	0	0	0	3.4	0	0	0	0	0
8			0	0	0	0	0	0	3.4	0	0	0	0	0
9			0	0	0	0	0	0	3.4	0	0	0	0	0
10			0	0	0	0	0	0	3.4	0	0	0	0	0
Total			115	1150000		3797500		3736500		3910000	-173500		190740	3927240
				3.30217		3.24913		3.4		-0.15087			0.16586	3.41499
NNG-PNC	84	0.73043	84	840000	3.30217	2773826	3.24913	2729270	3.4	2856000	-126730	0.16586	139323	2868593
NNG-NNI	10	0.08696	10	100000	3.30217	330217	3.24913	324913	3.4	340000	-15087	0.16586	16586.1	341499
GLGT-PN	3	0.02609	3	30000	3.30217	99065.2	3.24913	97473.9	3.4	102000	-4526.09	0.16586	4975.83	102450
GLGT-NN	6	0.05217	6	60000	3.30217	198130	3.24913	194948	3.4	204000	-9052.17	0.16586	9951.65	204899
VGT-PNG	3	0.02609	3	30000	3.30217	99065.2	3.24913	97473.9	3.4	102000	-4526.09	0.16586	4975.83	102450
VGT-NML	5	0.04348	5	50000	3.30217	165109	3.24913	162457	3.4	170000	-7543.48	0.16586	8293.04	170750
Centra	4	0.03478	4	40000	3.30217	132087	3.24913	129965	3.4	136000	-4034.78	0.16586	6634.43	136600
Total	115	1	115	1150000	3.30217	3797500	3.24913	3736500	3.4	3910000	-173500	0.16586	190740	3927240

41249

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41053		26	260000	3.5	910000	3.5	910000	3.803	988780	-78780	0.285	74100	984100
2	41086		28	280000	3.5	980000	3.5	980000	3.803	1064840	-84840	0.27	75600	1056600
3	41115		29	290000	3.75	1087500	3.75	1087500	3.803	1102870	-15370	0.19	55100	1142600
4	41149		31	310000	3.25	1007500	3.25	1007500	3.803	1178030	-171430	0.196	60760	1068260
5	41180		31	310000	3.75	1162500	3.75	1162500	3.803	1178030	-15530	0.141	43710	1206210
6	41197		31	310000	3.5	1085000	3.5	1085000	3.803	1178030	-93030	0.13	40300	1125300
7			0	0	0	0	0	0	3.803	0	0	0	0	0
8			0	0	0	0	0	0	3.803	0	0	0	0	0
9			0	0	0	0	0	0	3.803	0	0	0	0	0
10			0	0	0	0	0	0	3.803	0	0	0	0	0
Total			177	1770000		6427500		6364460		6731310	-366850		338070	6702530
				3.63136		3.59574				3.803	-0.20726		0.191	3.78674
NNG-PNC	130	0.73446	130	1300000	3.63136	4720763	3.59574	4674462	3.803	4943900	-269438	0.191	248300	4922762
NNG-NNI	15	0.08475	15	150000	3.63136	544703	3.59574	539361	3.803	570450	-31089	0.191	28650	568011
GLGT-PN	5	0.02825	5	50000	3.63136	181568	3.59574	179787	3.803	190150	-10363	0.191	9550	189337
GLGT-NN	9	0.05085	9	90000	3.63136	326822	3.59574	323617	3.803	342270	-18653.4	0.191	17190	340807
VGT-PNG	5	0.02825	5	50000	3.63136	181568	3.59574	179787	3.803	190150	-10363	0.191	9550	189337
VGT-NML	7	0.03955	7	70000	3.63136	254195	3.59574	251702	3.803	266210	-14508.2	0.191	13370	265072
Centra	6	0.0339	6	60000	3.63136	217881	3.59574	215744	3.803	228180	-12435.6	0.191	11460	227204
Total	177	1	177	1770000	3.63136	6427500	3.59574	6364460	3.803	6731310	-366850	0.191	338070	6702530

41280

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41053		29	290000	3.75	1087500	3.75	1087500	3.932	1140280	-52780	0.26	75400	1162900
2	41082		15	150000	3.75	562500	3.75	562500	3.932	589800	-27300	0.238	35700	598200
3	41082		16	160000	3.75	600000	3.75	600000	3.932	629120	-29120	0.24	38400	638400
4	41106		32	320000	3.5	1120000	3.5	1120000	3.932	1258240	-138240	0.33	105600	1225600
5	41195		32	320000	3.5	1120000	3.5	1120000	3.932	1258240	-138240	0.33	105600	1225600
6	41197		32	320000	3.75	1200000	3.75	1200000	3.932	1258240	-58240	0.182	58240	1258240
7			0	0	0	0	0	0	3.932	0	0	0	0	0
8			0	0	0	0	0	0	3.932	0	0	0	0	0
9			0	0	0	0	0	0	3.932	0	0	0	0	0
10			0	0	0	0	0	0	3.932	0	0	0	0	0
Total			192	1920000		7125000		7101880		7549440	-447560		455680	7557560
				3.71094		3.6989				3.932	-0.2331		0.23733	3.93623
NNG-PNC	140	0.72917	140	1400000	3.71094	5195313	3.6989	5178454	3.932	5504800	-326346	0.23733	332267	5510721
NNG-NNI	17	0.08854	17	170000	3.71094	630859	3.6989	628812	3.932	668440	-39627.7	0.23733	40346.7	669159
GLGT-PN	5	0.02604	5	50000	3.71094	185547	3.6989	184945	3.932	196600	-11655.2	0.23733	11866.7	196811
GLGT-NN	10	0.05208	10	100000	3.71094	371094	3.6989	369890	3.932	393200	-23310.4	0.23733	23733.3	393623
VGT-PNG	5	0.02604	5	50000	3.71094	185547	3.6989	184945	3.932	196600	-11655.2	0.23733	11866.7	196811
VGT-NML	8	0.04167	8	80000	3.71094	296875	3.6989	295912	3.932	314560	-18648.3	0.23733	18986.7	314898
Centra	7	0.03646	7	70000	3.71094	259766	3.6989	258923	3.932	275240	-16317.3	0.23733	16613.3	275536
Total	192	1	192	1920000	3.71094	7125000	3.6989	7101880	3.932	7549440	-447560	0.23733	455680	7557560

41311

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41062		33	330000	3.75	1237500	3.75	1237500	3.935	1298550	-61050	0.185	61050	1298550
2	41085		34	340000	3.75	1275000	3.75	1275000	3.935	1337390	-62390	0.185	62900	1337390
3	41103		26	260000	3.75	975000	3.935	1023100	-48100	0.31	80600	1055600
4	41151		26	260000	3.5	910000	3.935	1023100	-113100	0.251	65260	975260
5	41177		27	270000	3.75	1012500	3.75	1012500	3.935	1062450	-49950	0.215	58050	1070550
6	41206		29	290000	4	1160000	3.935	1141150	3.935	1141150	0	0.259	75110	1216260
7			0	0	0	0	0	0	3.935	0	0	0	0	0
8			0	0	0	0	0	0	3.935	0	0	0	0	0
9			0	0	0	0	0	0	3.935	0	0	0	0	0
10			0	0	0	0	0	0	3.935	0	0	0	0	0
Total			155	1550000		5760000		5741150		6096250	-358100		435130	6176280
				3.71613		3.70397				3.935	-0.23103		0.28073	3.98447
NNG-PNC	113	0.72903	113	1130000	3.71613	4199226	3.70397	4185484	3.935	4446550	-261066	0.28073	317224	4502707
NNG-NNI	13	0.08387	13	130000	3.71613	483097	3.70397	481516	3.935	511550	-30034.2	0.28073	36494.8	518011
GLGT-PN	4	0.02581	4	40000	3.71613	148645	3.70397	148159	3.935	157400	-9241.29	0.28073	11229.2	159388
GLGT-NN	8	0.05161	8	80000	3.71613	297290	3.70397	296317	3.935	314800	-18482.6	0.28073	22458.3	318776
VGT-PNG	4	0.02581	4	40000	3.71613	148645	3.70397	148159	3.935	157400	-9241.29	0.28073	11229.2	159388
VGT-NML	7	0.04516	7	70000	3.71613	260129	3.70397	259278	3.935	275450	-16172.3	0.28073	19651	278929
Centra	6	0.03871	6	60000	3.71613	222968	3.70397	222238	3.935	236100	-13861.9	0.28073	16843.7	239082
Total	155	1	155	1550000	3.71613	5760000	3.70397	5741150	3.935	6096250	-358100	0.28073	435130	6176280

41339

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41062		17	170000	3.75	637500	3.75	637500	3.905	663850	-26350	0.33	56100	693950
2	41085		17	170000	3.5	595000	3.5	595000	3.905	663850	-68850	0.285	48450	643450
3	41109		19	190000	3.75	712500	3.75	712500	3.905	741950	-29450	0.29	55100	767600
4	41151		21	210000	3.5	735000	3.5	735000	3.905	820050	-85050	0.275	57750	792750
5	41177		21	210000	3.75	787500	3.75	787500	3.905	820050	-32550	0.23	48300	835800
6	41206		21	210000	4	840000	3.905	820050	3.905	820050	0	0.298	62580	882630
7			0	0	0	0	0	0	3.905	0	0	0	0	0
8			0	0	0	0	0	0	3.905	0	0	0	0	0
9			0	0	0	0	0	0	3.905	0	0	0	0	0
10			0	0	0	0	0	0	3.905	0	0	0	0	0
Total			116	1160000		4307500		4287550		4529800	-242250		327940	4615490
				3.71336		3.69616				3.905	-0.20884		0.28271	3.97887
NNG-PNC	85	0.73276	85	850000	3.71336	3156358	3.69616	3141739	3.905	3319250	-177511	0.28271	240301	3382040
NNG-NNI	10	0.08621	10	100000	3.71336	371336	3.69616	369616	3.905	390500	-20883.6	0.28271	28270.7	397887
GLGT-PN	3	0.02586	3	30000	3.71336	111401	3.69616	110885	3.905	117150	-6265.09	0.28271	8481.21	119366
GLGT-NN	6	0.05172	6	60000	3.71336	222802	3.69616	221770	3.905	234300	-12530.2	0.28271	16962.4	238732
VGT-PNG	3	0.02586	3	30000	3.71336	111401	3.69616	110885	3.905	117150	-6265.09	0.28271	8481.21	119366
VGT-NML	5	0.0431	5	50000	3.71336	185668	3.69616	184808	3.905	195250	-10441.8	0.28271	14135.3	198944
Centra	4	0.03448	4	40000	3.71336	148534	3.69616	147847	3.905	156200	-8353.45	0.28271	11308.3	159155
Total	116	1	116	1160000	3.71336	4307500	3.69616	4287550	3.905	4529800	-242250	0.28271	327940	4615490

Total

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settl Cost	Over/(Und Market	Premium Per Unit	Premium Cost	Total Cost
1	41053		111	1110000	3.4833	3867500	3.4833	3867500	3.83743	4261960	-394460	0.3606	329035	4590535
2	41085		101	1010000	3.4926	3530000	3.4926	3530000	3.83596	3848860	-318860	0.3615	307835	3837835
3	41114		109	1090000	3.70642	4040000	3.68899	4021000	3.80095	4143040	-122040	0.24671	268910	4289910
4	41151		131	1310000	3.36099	4402500	3.36099	4402500	3.81246	4994320	-591820	0.24927	326540	4729040
5	41177		132	1320000	3.64962	4817500	3.63371	4796500	3.81339	5033670	-237170	0.1742	229940	5026440
6	41206		137	1370000	3.86131	5290000	3.77165	5167160	3.81682	5228040	-61880	0.18189	249190	5416350
7			34	340000	4	1360000	3.932	1336880	3.932	1336880	0	0.197	66980	1403860
8			0	0	0	0	0	0	0	0	0	0	0	0
9			0	0	0	0	0	0	0	0	0	0	0	0
10			0	0	0	0	0	0	0	0	0	0	0	0
Total			755	7550000		2.7E+07		2.7E+07		2.9E+07	-1588260		1747560	2.9E+07
				3.63146		3.60683				3.81719	-0.21037		0.23146	3.83829
NNG-PNC	552	0.73113	552	5520000	3.63146	2E+07	3.60683	2E+07	3.81719	2.1E+07	-1161218	0.23146	1277666	2.1E+07
NNG-NNI	65	0.08609	65	650000	3.63146	2360447	3.60683	2344437	3.81719	2481175	-136738	0.23146	150452	2494889
GLGT-PN	20	0.02649	20	200000	3.63146	726291	3.60683	721365	3.81719	763438	-42073.1	0.23146	46293	767658
GLGT-NN	39	0.05166	39	390000	3.63146	1416268	3.60683	1406662	3.81719	1488705	-82042.6	0.23146	90271.3	1496934
VGT-PNG	20	0.02649	20	200000	3.63146	726291	3.60683	721365	3.81719	763438	-42073.1	0.23146	46293	767658
VGT-NML	32	0.04238	32	320000	3.63146	1162066	3.60683	1154184	3.81719	1221501	-67317	0.23146	74068.8	1228253
Centra	27	0.03576	27	270000	3.63146	980493	3.60683	973843	3.81719	1030642	-56798.7	0.23146	62495.5	1036339
Total	755	1	755	7550000	3.63146	2.7E+07	3.60683	2.7E+07	3.81719	2.9E+07	-1588260	0.23146	1747560	2.9E+07