MICHAEL J. AHERN
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November 1, 2011

VIA ELECTRONIC FILING

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

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–PNG for Approval of a Change in Demand Entitlement for its 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, 2011

To: Service List

RE: Minnesota Energy Resources Corporation-PNG Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-PNG has filed a petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement.

To obtain copies, or if you have any questions, please contact:

Gregory J. Walters
Minnesota Energy Resources Corporation
3460 Technology Drive NW
Rochester, MN 55901
507-529-5100.

Please note that this filing is also available through the eDockets system maintained by the Minnesota Department of Commerce and the Minnesota Public Utilities Commission. You can access this document by going to eDockets through the websites of the Department of Commerce or the Public Utilities Commission or going to the eDockets homepage at:

https://www.edockets.state.mn.us/EFiling/home.jsp

Once on the eDockets homepage, this document can be accessed through the Search Documents link and by entering the date of the filing.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its 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 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, 2011.

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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its 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 (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, 2011.

This filing includes the following attachments:

Attachment 1: Notice of Availability.

Attachment 2: One paragraph summary of the filing in accordance with Minn. R. 7829.1300, subp. 1.

Attachment 3: Petition for Change in Demand with Attachments.

Attachment 4: Affidavit of Service and Service List.

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

1. Summary of Filing

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

2. Service

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

3. General Filing Information

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

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

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

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

C. Date of the Filing and Proposed Effective Date

Date of filing: November 1, 2011
Proposed Effective Date: November 1, 2011

D. Statute Controlling Schedule for Processing the Filing

Minnesota Statutes and related rules do not provide an explicit time frame for action by the Commission. Under Minn. R. 7829.1400, initial comments are due within 30 days of filing, with reply comments due 10 days thereafter.

E. Utility Employee Responsible for the Filing

Gregory J. Walters
3460 Technology Drive NW
Rochester, MN 55901
(507) 529-5100

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

DATED: November 1, 2011

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy
Resources Corporation

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Phyllis A. Reha	Commissioner
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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its 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, 2011.

II. DISCUSSION

A. MERC's PNG-VGT Design Day Requirements

MERC's 2011-2012 PNG-VGT design day requirements decreased 441 Mcf (or approximately 6.05 percent) from 7,292 Mcf to 6,851 Mcf.

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

	Reserve Margin 2011-2012 Heating Season	Reserve Margin 2010-2011 Heating Season	Change
VGT-PNG	3.87%	19.62%	-15.75%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for PNG-VGT for the 2011-2012 heating season is positive.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for PNG-VGT is 6,851 Dth as calculated in Attachment 1, page 2 and Attachment 3.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity for PNG-VGT is 7,116 Dth as calculated in Attachment 3.

The difference between the total Design Day requirement and total Design Day capacity results in a 3.87% 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 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 an ideal world, the Team would have also had daily telemetered data from each interruptible, transportation, and joint interruptible customer mapped to each of the demand areas and related weather stations. This was the case for a handful of paper mills, direct-connects, taconites, and off-system end users. The rest of the interruptible, transportation, and joint interruptible data was available based on monthly billing cycle data that introduces billing lag, meter read lag (not all meters were read every month, resulting in billing cycle estimates and reversals), and other potential errors into their volumes.

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

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

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

[2] Temperature and weather data was obtained from Weather Bank/DTN via TherMaxx then converted to HDD65 and AHDD65 in an Excel spreadsheet by MERC – Gas Supply. Temperature and wind data is 24-hour average based on the 9am to 9am gas day.

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

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

III. Volume Risk Adjustments

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

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

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

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

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

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

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

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

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

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

B. Add back Daily Firm Capacity (DFC) Customer Selections

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

C. Apply Sales Forecast Growth Rates

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

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

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 purchased firm winter only capacity (November 2011 through March 2012) to replace the 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. The cost of TCPL would have been approximately $927,919 compared to the $417,042 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 2011 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 $43,824 for the 2011-2012 winter. Please see Attachment 5.

iii. MERC entered into 17 contracts (10,000/contract) or 170,000. Total premium per contract is approximately $.2578. 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 2011-2012 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 2011 through March 2012 period as well as the planned physical fixed price, financial call options and storage and/or exchange volumes by month.

F. <u>Price Volatility</u>

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 $4.527. Please see Attachment 12, page 1 of 3. MERC is projecting the AECO Storage WACOG for PNG-VGT to be approximately $3.786. 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 $4.6295, which means if NYMEX contract(s) settle above that price, the options are exercised and MERC's customers gas cost is capped at the average strike price. Please see Attachment 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 $4.32 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $4.6295 strike price plus the physical index basis spread. If the NYMEX prices are below the average $4.6295 strike price, the average natural gas cost for 70% of the normal winter volumes will be lower. The remaining 30% of normal winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium or margin costs.

G. <u>PGA Cost Recovery</u>

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2011. Rate impacts associated with this change can be found on Attachment 4, pages 1 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.

H. Impacts of Telemetry

Based on the requirement that all interruptible and transportation customers on MERC's system must have telemetry, this has led to some customers switching from interruptible to firm. On the PNG-VGT, there have been twelve (12) customers that switched from interruptible to firm service. The switching occurred between February 16, 2011 through August 12, 2011. Since MERC's peak day analysis is based on December through February volumes for the three previous winters, for the most part, these volumes aren't represented in MERC's design day analysis. MERC projected the impact on firm requirements by projecting peak day volumes for the customers that switched. The projected peak day was calculated by taking actual peak day and dividing the volume by twenty (20). MERC is projecting an increase in design day of 873 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, 2010. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2011

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

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

/s/ Amber S. Lee
Amber S. Lee

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

/s/ Sara Garcia
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
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Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

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

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-PNG

Demand Entitlement Schedules - VGT

MINNESOTA ENERGY RESOURCES - PNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2011
VGT

Design Day Requirement		6,851
Total Entitlement on Peak Day(excl. Peak Shaving)		7,116
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 20)	5,287
Firm Annual Throughput - Minnesota		582,120
No. of Firm Customers		4,672
DPS Load Factor Calculation		30.17%

MINNESOTA ENERGY RESOURCES - PNG

MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2011

VGT

Pipeline Group	Nov10-Mar 11 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	Nov10-Mar 11 Avg. Customer Growth	Total
PEAK									
	4,672	109	1,172	73	9,068	2,162	6,906	-0.8%	6,851
Total	4,672								6,851
OFF PEAK									
	4,672	57	1,172	73	5,318	1,081	4,237	-0.8%	4,204
Total	4,672								4,204

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, 2011

VGT

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
11/12	4,672	6,851	1.47
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 2012
VGT

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	159,431	411,183	570,614
SVI	54,458	136,183	190,641
SVJ	3,954	7,553	11,506
LVI	0	0	0
Total	217,842	554,918	772,761

MINNESOTA ENERGY RESOURCES - PNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2011

VGT

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
AF0012	3,527	1,255	4,782
AF0014 (Dec-Feb) *	1,098	(678)	420
AF0016	1,000	(1,000)	0
AF0102	2,000	(1,234)	766
AF0183	0	1,148	1,148
Wadena Delivered Option	1,098	(1,098)	0
Heating Season Total	8,723	(1,607)	7,116
Non-Heating Season Total	6,527	(979)	5,548
Total Entitlement	8,723	(1,607)	7,116
Heating Season Forecasted Design Day	7,292	(441)	6,851
Non-Heating Season Forecasted Design Day	4,228	(24)	4,204
Heating Season Capacity Surplus/Shortage	734	(469)	265
Non-Heating Season Capacity Surplus/Shortage	2,299	(955)	1,344
Reserve Margin	10.07%		3.87%

*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, 2011

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR10-978* Feb. 11	Demand Change G011- M-09-XXXX Oct 09	Last Demand Change G011- M-10-XXXX Oct. 10	VGT Most Recent PGA** Oct. 2011	Current Proposal Effective Nov.1,2011	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service Residential: Avg. Annual Use:				82	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost	$1.0565	$1.0908	$0.9994	$0.8815	$0.7951	-24.74%	-20.44%	-9.80%	($0.0864)
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.3383	$6.3855	$6.5605	$6.4251	$6.6367	-20.41%	1.16%	3.29%	$0.2116
Avg Annual Cost	$683.74	$523.61	$537.96	$526.86	$544.21	-20.41%	1.16%	3.29%	$17.35
Effect of proposed commodity changeon average annual bills:									$24.43
Effect of proposed demand charge on average annual bills:									($7.08)
2) Small Vol. Interruptible: Avg. Annual Use:				3,859	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost									
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9118	$4.9546	$4.9371	$5.2351	-21.58%	5.66%	6.04%	$0.2980
Avg Annual Cost	$25,759.98	$18,954.64	$19,119.80	$19,052.27	$20,202.11	-21.58%	5.66%	6.04%	$1,149.84
Effect of proposed commodity changeon average annual bills:									$1,149.84
Effect of proposed demand charge on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:				89,334	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost									
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.8320	$4.0276	$4.1113	$4.0938	$4.3918	-24.70%	6.82%	7.28%	$0.2980
Avg Annual Cost	$520,995.89	$359,801.62	$367,278.87	$365,715.53	$392,333.87	-24.70%	6.82%	7.28%	$26,618.34
Effect of proposed commodity change onaverage annual bills:									$26,618.34
Effect of proposed demand charge on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:				2,860	Mcf				
Agg. Annual CD Units:				15					
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost	$6.6801	$3.4671	$3.4671	$3.4671	$3.4671	-48.10%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9118	$4.9546	$4.9371	$5.2351	-21.58%	5.66%	6.04%	$0.2980
Total Demand Cost	$8.4801	$5.5395	$5.2671	$5.2671	$5.2671	-37.89%	0.00%	0.00%	$0.0000
Avg Annual Cost	$19,218.56	$14,130.84	$14,249.16	$14,199.11	$15,051.29	-21.68%	5.63%	6.00%	$852.18
Effect of proposed commodity change on aveage annual bills:									$852.18
Effect of proposed demand charge on average annual bills:									$0.00

Note: Average Annual Average basedon PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-11-793
*As submitted in Docket No. G007,011MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/chaarges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-178

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-11**	**CURRENT**	
	Commodity From Schedule D					$0.40598	/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-11**	**CURRENT**	
			Monthly Entitlemen	**Months**	**Rate $/Dth**		**Contract Cost**	**$/therm**
A. GS-4	FT-A ZONE 1 - 1	AF0012	4,782	12	$3.4671	=	$198,956	$0.03305
	FT-A ZONE 1 - 1	AF0014	420	3	$3.4671	=	$4,369	$0.00073
	FT-A ZONE 1 - 1	AF0102	766	12	$3.4671	=	$31,870	$0.00529
	FT-A ZONE 1 - 1	AF0183	1,148	5	$3.7671	=	$21,623	$0.00359
	Balancing Agreement	ML0021	2,858	12	$1.0000	=	$34,296	$0.00570
							$291,113	$0.04836
	Niska Storage		134,401	1	$0.95482	=	$ 128,329	$0.02132
	AECO/Emerson Swap		134,401	1	$0.44000	=	$ 59,137	$0.00982
	Total Storage Demand						$187,466	$0.03114
	Rate Case 2008 Firm Annual Sales in therms						6,019,240	
	Current Demand Cost of Gas $/therm							**$0.07951**
	Current T-17 Commodity Cost of Gas							$0.40598
	Call Option Premium				$6,049.62	8,444,190		$0.00072
	GS-5 Total Current Commodity Cost of Gas $/therm							**$0.40670**
	Current Total Cost of Gas $/therm							$0.48621
B. SVI-4	Current Commodity Cost of Gas/CCf							$0.40670
C. SJ-4	Current Demand Cost of Gas/CCf							$0.34671
	Current Commodity Cost of Gas/CCf							$0.40670
D. LVI-4	Current Commodity Cost of Gas/CCf							$0.40670

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, 2011

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR10-978* Feb. 11	Demand Change G011- M-09-XXXX Oct 09	Last Demand Change G011- M-10-XXXX Oct. 10	VGT Most Recent PGA Oct. 2011	Current Proposal Effective Nov.1,2011	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:				82	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost	$1.0565	$1.0908	$0.9994	$0.8815	$0.4316	-59.15%	-56.82%	-51.04%	($0.4499)
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.3383	$6.3855	$6.5605	$6.4251	$6.5763	-21.13%	0.24%	2.35%	$0.1512
Avg Annual Cost	$683.74	$523.61	$537.96	$526.86	$539.26	-21.13%	0.24%	2.35%	$12.40
Effect of proposed commodity change on average annual bills:									$49.29
Effect of proposed demand change on average annual bills:									($36.89)
2) Small Vol. Interruptible: Avg. Annual Use:				3,859	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost									
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9118	$4.9546	$4.9371	$5.5382	-17.03%	11.78%	12.18%	$0.6011
Avg Annual Cost	$25,759.98	$18,954.64	$19,119.80	$19,052.27	$21,371.93	-17.03%	11.78%	12.18%	$2,319.66
Effect of proposed commodity change on average annual bills:									$2,319.66
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:				89,334	Mcf				
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost									
Commodity Margin	$0.3248	$0.3592	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.8320	$4.0276	$4.1113	$4.0938	$4.6949	-19.50%	14.20%	14.68%	$0.6011
Avg Annual Cost	$520,995.89	$359,801.62	$367,278.87	$365,715.53	$419,414.54	-19.50%	14.20%	14.68%	$53,699.02
Effect of proposed commodity change on average annual bills:									$53,699.02
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:				2,860	Mcf				
Avg. Annual CD Units:				15					
Commodity Cost	$5.5072	$3.6684	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost	$6.6801	$3.4671	$3.4671	$3.4671	$3.4671	-48.10%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9118	$4.9546	$4.9371	$5.5382	-17.03%	11.78%	12.18%	$0.6011
Total Demand Cost	$8.4801	$5.5395	$5.2671	$5.2671	$5.2671	-37.89%	0.00%	0.00%	$0.0000
Avg Annual Cost	$19,218.56	$14,130.84	$14,249.16	$14,199.11	$15,918.27	-17.17%	11.71%	12.11%	$1,719.16
Effect of proposed commodity change on average annual bills:									$1,719.16
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-11-793
*As submitted in Docket No. G007,011/MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781

MINNESOTA ENERGY RESOURCES-PNG
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-11**	**CURRENT**	
	Commodity From Schedule D					$0.40598	/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-11**	**CURRENT**	
			Monthly Entitlemen	**Months**	**Rate $/Dth**		**Contract Cost**	**$/therm**
A. GS-4	FT-A ZONE 1 - 1	AF0012	4,782	12	$3.4671	=	$198,956	$0.03305
	FT-A ZONE 1 - 1	AF0014	420	3	$3.4671	=	$4,369	$0.00073
	FT-A ZONE 1 - 1	AF0102	766	12	$3.4671	=	$31,870	$0.00529
	FT-A ZONE 1 - 1	AF0183	1,148	5	$3.7671	=	$21,623	$0.00359
	Balancing Agreement	ML0021	2,858	12	$1.0000	=	$2,965	$0.00049
							$259,782	$0.04316
	Niska Storage		134,401	0	$0.95482	=	$0	$0.00000
	AECO/Emerson Swap		134,401	0	$0.44000	=	$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							**$0.04316**
	Current T-17 Commodity Cost of Gas							$0.40598
	Call Option Premium				$6,049.62	8,444,190		$0.00072
	Niska Storage		134,401	1	$1.42643	=	$192,139	$0.02275
	AECO/Emerson Swap		134,401	1	$0.47498	=	$63,838	$0.00756
	GS-5 Total Current Commodity Cost of Gas $/therm							**$0.43701**
	Current Total Cost of Gas $/therm							$0.48017
B. SVI-4	Current Commodity Cost of Gas/CCf							$0.43701
C. SJ-4	Current Demand Cost of Gas/CCf							$0.34671
	Current Commodity Cost of Gas/CCf							$0.43701
D. LVI-4	Current Commodity Cost of Gas/CCf							$0.43701

MINNESOTA ENERGY RESOURCES - PNG-VGT

Financial Options

Heating Season 2011-2012

[TRADE SECRET DATA BEGINS

Units - Gas Daily Packages

|

Units - Futures (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1												
2												
3												
4												
5												
6												
7												
8												
Total		667		645		645		345		968	3,270	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		1,379		968	5,605	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	$ 0.2017	$ 6,050	$ 0.2220	$ 6,661	$ 0.2638	$ 10,551	$ 0.2950	$ 11,392	$ 0.3057	$ 9,171	$ 0.2578	$ 43,824

Units - Collar Floor (put)

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES - PNG

2008-09			2009-10			
G011/M-08-XXXX	Quantity (Mcf)		G011/M-09-XXXX	Quantity (Mcf)		
FT-A 12 months	6,527	2/	FT-A 12 months	6,527		
FT-A 3 months	1,098		FT-A 3 months	1,098		
FT-A (5 month backhaul)	0	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)	172		TF12 (NNG)	432		
TF5 (NNG)	389		TF5 (NNG)	105		
TFX12 (NNG)	432		TFX12 (NNG)	389		
TFX5 (NNG)	105		TFX5 (NNG)	172		
FT-D 12 months	0		FT-D 12 months	0		
			#REF!	0		
Total Design Day Capacity	7,625		Total Design Day Capacity	7,625		
Total Viking Transportation	7,625		Total Viking Transportation	7,625		
Total Annual Transportation	7,131		Total Annual Transportation	7,348		
Total Seasonal Transport	1,592		Total Seasonal Transport	1,375		
Percent Seasonal on Viking	20.9%		Percent Seasonal on Viking	18.0%		

2010-11			2011-12			Change in
G011/M-11-XXXX	Quantity (Mcf)		G011/M-11-XXXX	Quantity (Mcf)		Quantity
FT-A 12 months	6,527		FT-A 12 months	5,548		(979)
FT-A 3 months	1,098		FT-A 3 months	420		(678)
FT-A 5 months	0		FT-A 5 months	1,148		1,148
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)	0	1/	(1,098)
TF12 (NNG)	0		TF12 (NNG)	0		0
TF5 (NNG)	0		TF5 (NNG)	0		0
TFX12 (NNG)	0		TFX12 (NNG)	0		0
TFX5 (NNG)	0		TFX5 (NNG)	0		0
FT-D 12 months	0		FT-D 12 months	0		0
Wadena Delivered Option	1,098		Wadena Delivered Option	0		(1,098)
Total Design Day Capacity	8,723		Total Design Day Capacity	7,116		(1,607)
Total Viking Transportation	8,723		Total Viking Transportation	7,116		(1,607)
Total Annual Transportation	7,625		Total Annual Transportation	5,548		(2,077)
Total Seasonal Transport	2,196		Total Seasonal Transport	1,568		(628)
Percent Seasonal on Viking	25.2%		Percent Seasonal on Viking	22.0%		-3.14%

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/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost of Gas	$1.0565	$0.9994	$0.8815	$0.7951	-24.74%	-20.44%	-9.80%	($0.0864)
Commodity Margin	$1.7746	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.3383	$6.5605	$6.4251	$6.6367	-20.41%	1.16%	3.29%	$0.2116
Average Annual Usage (Mcf)	82	82	82	82				
Average Annual Total Cost of Gas	$683.74	$537.96	$526.86	$544.21	-20.41%	1.16%	3.29%	$17.35

General Service	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost of Gas								$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9546	$4.9371	$5.2351	-21.58%	5.66%	6.04%	$0.2980
Average Annual Usage (Mcf)	3,859	3,859	3,859	3,859				
Average Annual Total Cost of Gas	$25,759.98	$19,119.80	$19,052.27	$20,202.11	-21.58%	5.66%	6.04%	$1,149.84

Large Volume Interruptible	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost of Gas								$0.0000
Commodity Margin	$0.3248	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.8320	$4.1113	$4.0938	$4.3918	-24.70%	6.82%	7.28%	$0.2980
Average Annual Usage (Mcf)	89,334	89,334	89,334	89,334				
Average Annual Total Cost of Gas	$520,995.89	$367,278.87	$365,715.53	$392,333.87	-24.70%	6.82%	7.28%	$26,618.34

Small Volume Firm/Interruptible	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.0670	-26.15%	7.41%	7.91%	$0.2980
Demand Cost of Gas	$6.6801	$3.4671	$3.4671	$3.4671	-48.10%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.6753	$4.9546	$4.9371	$5.2351	-21.58%	5.66%	6.04%	$0.2980
Total Demand Cost	$8.4801	$5.2671	$5.2671	$5.2671	-37.89%	0.00%	0.00%	$0.0000
Total Recovery	$15.1554	$10.2217	$10.2042	$10.5022	-30.70%	2.74%	2.92%	$0.2980
Average Annual Usage (Mcf)*	2,860	2,860	2,860	2,860				
Average Annual CD units (Mcf)	15	15	15	15				
Average Annual Commodity Bill^	$19,218.56	$14,249.16	$14,199.11	$15,051.29	-21.68%	5.63%	6.00%	$852.18

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Service	$0.2980	29.80%	($0.0864)	-9.80%	$0.2116	3.29%	$17.35
Small Volume Interruptible	$0.2980	29.80%	$0.0000	0.00%	$0.2980	6.04%	$1,149.84
Large Volume Interruptible	$0.2980	29.80%	$0.0000	0.00%	($0.2980)	7.28%	$26,618.34
Small Volume Firm	$0.2980	29.80%	$0.0000	0.00%	$0.0000	0.00%	$852.18

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

MINNESOTA ENERGY RESOURCES - PNG

General Service	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost of Gas	$1.0565	$0.9994	$0.8815	$0.4316	-59.15%	-56.82%	-51.04%	($0.4499)
Commodity Margin	$1.7746	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.3383	$6.5605	$6.4251	$6.5763	-21.13%	0.24%	2.35%	$0.1512
Average Annual Usage (Mcf)	82	82	82	82				
Average Annual Total Cost of Gas	$683.74	$537.96	$526.86	$539.26	-21.13%	0.24%	2.35%	$12.40

General Service	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost of Gas								$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6753	$4.9546	$4.9371	$5.5382	-17.03%	11.78%	12.18%	$0.6011
Average Annual Usage (Mcf)	3,859	3,859	3,859	3,859				
Average Annual Total Cost of Gas	$25,759.98	$19,119.80	$19,052.27	$21,371.93	-17.03%	11.78%	12.18%	$2,319.66

Large Volume Interruptible	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost of Gas								$0.0000
Commodity Margin	$0.3248	$0.3248	$0.3248	$0.3248	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.8320	$4.1113	$4.0938	$4.6949	-19.50%	14.20%	14.68%	$0.6011
Average Annual Usage (Mcf)	89,334	89,334	89,334	89,334				
Average Annual Total Cost of Gas	$520,995.89	$367,278.87	$365,715.53	$419,414.54	-19.50%	14.20%	14.68%	$53,699.02

Small Volume Firm/Interruptible	Base Cost of Gas Change G011/MR10-978	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost of Gas (WACOG)	$5.5072	$3.7865	$3.7690	$4.3701	-20.65%	15.41%	15.95%	$0.6011
Demand Cost of Gas	$6.6801	$3.4671	$3.4671	$3.4671	-48.10%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.6753	$4.9546	$4.9371	$5.5382	-17.03%	11.78%	12.18%	$0.6011
Total Demand Cost	$8.4801	$5.2671	$5.2671	$5.2671	-37.89%	0.00%	0.00%	$0.0000
Total Recovery	$15.1554	$10.2217	$10.2042	$10.8053	-28.70%	5.71%	5.89%	$0.6011
Average Annual Usage (Mcf)*	2,860	2,860	2,860	2,860				
Average Annual CD units (Mcf)	15	15	15	15				
Average Annual Commodity Bill^	$19,218.56	$14,249.16	$14,199.11	$15,918.27	-17.17%	11.71%	12.11%	$1,719.16

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Service	$0.6011	60.11%	($0.4499)	-51.04%	$0.1512	2.35%	$12.40
Small Volume Interruptible	$0.6011	60.11%	$0.0000	0.00%	$0.6011	12.18%	$2,319.66
Large Volume Interruptible	$0.6011	60.11%	$0.0000	0.00%	($0.6011)	14.68%	$53,699.02
Small Volume Firm	$0.6011	60.11%	$0.0000	0.00%	$0.0000	0.00%	$1,719.16

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

MINNESOTA ENERGY RESOURCES - PNG

	Oct-11 Entitlement	Nov-11 Entitlement	Entitlement Change	Months	Oct. 2011 Tariff Rate	Oct. 2011 Total Cost	Nov. 2011 Total Cost	Entitlement Change
FT-A (AF0012)	3,527	4,782	1,255	12	$3.4671	$146,742	$198,956	$52,215
FT-A (AF0014)	1,098	420	-678	3	$3.4671	$11,421	$4,369	-$7,052
FT-A (AF0016)	1,000	0	-1,000	12	$3.4671	$41,605	$0	-$41,605
FT-A (AF0102)	2,000	766	-1,234	12	$3.4671	$83,210	$31,870	-$51,341
FT-A (AF0183)	0	1,148	1,148	5	$3.7671	$0	$21,623	$21,623
Balancing Agreement	0	2,858	2,858	12	$1.0000	$0	$34,296	$34,296
Wadena Delivered Option	1,098	0	-1,098	0	$0.0000	$2,965	$0	-$2,965
Niska Storage	128,469	134,401	5,932	1	$0.9548	$183,659	$128,329	-$55,330
AECO/Emerson Swap	128,464	134,401	5,937	1	$0.4400	$61,020	$59,137	-$1,883
Total Demand Cost						$530,622	$478,579	-$52,042

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

MINNESOTA ENERGY RESOURCES - PNG

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

[TRADE SECRET DATA BEGINS]

10,000 Contract Size

REVISED:

System	Purchase Month	Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
		Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
VGT -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Contracts														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														
Month/Daily														
Total													554,918	**100.00%**

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

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
										-
										-
										-
										-
	Total Actual Fixed/Option Physical				-	-	-	-	-	-

INDEX - VGT	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	Total Actual Seasonal Index			1,667	1,613	1,936	1,725	1,936	270,044

GAS DAILY PACKAGES

STORAGE

Injection Month	Contract # Volume Injected	Total Volume Injected

MINNESOTA ENERGY RESOURCES - PNG

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

Base	768
Variable	80

Date	100.00% Bemidji Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put
7/1/10	0	0	837	768
7/2/10	0	0	677	768
7/3/10	0	0	558	768
7/4/10	0	0	516	768
7/5/10	0	0	599	768
7/6/10	0	0	844	768
7/7/10	0	0	936	768
7/8/10	0	0	909	768
7/9/10	0	0	742	768
7/10/10	0	0	586	768
7/11/10	4	4	661	1,110
7/12/10	0	0	875	768
7/13/10	0	0	880	768
7/14/10	0	0	897	768
7/15/10	0	0	880	768
7/16/10	0	0	747	768
7/17/10	0	0	624	768
7/18/10	0	0	670	768
7/19/10	0	0	859	768
7/20/10	0	0	882	768
7/21/10	0	0	852	768
7/22/10	0	0	879	768
7/23/10	0	0	752	768
7/24/10	0	0	620	768
7/25/10	0	0	617	768
7/26/10	0	0	805	768
7/27/10	0	0	849	768
7/28/10	0	0	877	768
7/29/10	0	0	858	768
7/30/10	0	0	733	768
7/31/10	0	0	572	768
8/1/10	0	0	600	768
8/2/10	0	0	819	768
8/3/10	0	0	839	768
8/4/10	0	0	876	768
8/5/10	1	1	890	854
8/6/10	1	1	759	850
8/7/10	0	0	641	768
8/8/10	0	0	691	768
8/9/10	0	0	813	768
8/10/10	0	0	831	768
8/11/10	0	0	837	768
8/12/10	0	0	893	768
8/13/10	0	0	732	768
8/14/10	1	1	665	860
8/15/10	9	9	900	1,491
8/16/10	12	12	1,133	1,736
8/17/10	1	1	887	855
8/18/10	10	10	936	1,592
8/19/10	0	0	883	768
8/20/10	0	0	693	768
8/21/10	0	0	592	768
8/22/10	0	0	647	768
8/23/10	0	0	847	768
8/24/10	10	10	936	1,582
8/25/10	6	6	882	1,277
8/26/10	0	0	844	768
8/27/10	0	0	692	768
8/28/10	0	0	577	768
8/29/10	0	0	711	768
8/30/10	0	0	782	768
8/31/10	6	6	823	1,208
9/1/10	0	0	865	768
9/2/10	9	9	929	1,517
9/3/10	16	16	901	2,022
9/4/10	16	16	733	2,016
9/5/10	11	11	692	1,624
9/6/10	10	10	774	1,582
9/7/10	18	18	1,199	2,176
9/8/10	14	14	967	1,860
9/9/10	13	13	1,140	1,771
9/10/10	11	11	1,009	1,664
9/11/10	11	11	787	1,664
9/12/10	13	13	852	1,824
9/13/10	11	11	1,029	1,624
9/14/10	13	13	1,139	1,786
9/15/10	22	22	1,447	2,532
9/16/10	9	9	1,230	1,466
9/17/10	20	20	1,360	2,366
9/18/10	19	19	1,221	2,280
9/19/10	11	11	1,141	1,616
9/20/10	11	11	1,295	1,672
9/21/10	19	19	1,563	2,309
9/22/10	14	14	1,374	1,912
9/23/10	17	17	1,578	2,112

9/24/10	14	14	1,404	1,881
9/25/10	14	14	1,141	1,922
9/26/10	4	4	1,630	1,120
9/27/10	6	6	1,098	1,286
9/28/10	3	3	1,124	1,025
9/29/10	8	8	1,092	1,390
9/30/10	9	9	1,180	1,453
10/1/10	22	22	1,435	2,496
10/2/10	19	19	1,429	2,318
10/3/10	12	12	1,402	1,736
10/4/10	8	8	1,306	1,384
10/5/10	1	1	1,114	858
10/6/10	10	10	1,305	1,546
10/7/10	2	2	1,144	934
10/8/10	0	0	833	768
10/9/10	0	0	711	768
10/10/10	2	2	708	931
10/11/10	0	0	1,071	768
10/12/10	16	16	1,435	2,011
10/13/10	12	12	1,521	1,736
10/14/10	18	18	1,740	2,237
10/15/10	12	12	1,469	1,736
10/16/10	22	22	1,572	2,560
10/17/10	23	23	1,777	2,634
10/18/10	21	21	2,119	2,425
10/19/10	13	13	1,769	1,824
10/20/10	23	23	2,067	2,592
10/21/10	24	24	2,158	2,718
10/22/10	12	12	1,611	1,701
10/23/10	21	21	1,751	2,425
10/24/10	19	19	1,661	2,309
10/25/10	15	15	1,808	1,933
10/26/10	21	21	3,050	2,467
10/27/10	37	37	3,560	3,720
10/28/10	37	37	3,610	3,733
10/29/10	28	28	2,781	3,014
10/30/10	30	30	2,637	3,204
10/31/10	28	28	2,459	3,014
11/1/10	19	19	2,439	2,294
11/2/10	20	20	2,407	2,352
11/3/10	25	25	2,588	2,792
11/4/10	36	36	3,168	3,646
11/5/10	31	31	2,683	3,227
11/6/10	23	23	2,175	2,598
11/7/10	20	20	1,806	2,394
11/8/10	18	18	1,919	2,237
11/9/10	14	14	1,680	1,922
11/10/10	19	19	2,502	2,264
11/11/10	32	32	3,046	3,320
11/12/10	31	31	3,007	3,216
11/13/10	34	34	2,943	3,482
11/14/10	37	37	3,182	3,763
11/15/10	38	38	3,463	3,808
11/16/10	35	35	3,532	3,597
11/17/10	47	47	4,270	4,552
11/18/10	46	46	4,110	4,474
11/19/10	54	54	4,724	5,092
11/20/10	51	51	4,498	4,816
11/21/10	49	49	4,496	4,706
11/22/10	61	61	5,665	5,608
11/23/10	56	56	5,197	5,261
11/24/10	59	59	5,074	5,517
11/25/10	68	68	5,482	6,192
11/26/10	61	61	5,296	5,651
11/27/10	54	54	4,146	5,093
11/28/10	33	33	3,378	3,446
11/29/10	41	41	4,422	4,083
11/30/10	61	61	5,633	5,623
12/1/10	61	61	5,758	5,647
12/2/10	64	64	6,127	5,926
12/3/10	58	58	5,305	5,388
12/4/10	56	56	5,025	5,261
12/5/10	52	52	4,934	4,923
12/6/10	62	62	5,608	5,760
12/7/10	60	60	5,677	5,547
12/8/10	56	56	5,617	5,219
12/9/10	50	50	4,839	4,800
12/10/10	62	62	5,350	5,733
12/11/10	78	78	6,420	7,046
12/12/10	78	78	6,940	6,984
12/13/10	77	77	6,467	6,900
12/14/10	59	59	5,833	5,520
12/15/10	57	57	5,125	5,304
12/16/10	59	59	5,388	5,520
12/17/10	57	57	5,445	5,338
12/18/10	57	57	5,258	5,347
12/19/10	61	61	5,300	5,630
12/20/10	52	52	4,907	4,904
12/21/10	42	42	4,619	4,106
12/22/10	44	44	4,628	4,311
12/23/10	48	48	4,163	4,632
12/24/10	54	54	4,348	5,052
12/25/10	58	58	4,844	5,382
12/26/10	56	56	5,132	5,256
12/27/10	47	47	4,863	4,552
12/28/10	40	40	4,095	3,965

12/29/10	40	40	3,646	3,935
12/30/10	59	59	4,958	5,469
12/31/10	65	65	5,394	5,965
1/1/11	79	79	5,902	7,096
1/2/11	73	73	6,021	6,586
1/3/11	72	72	6,558	6,509
1/4/11	59	59	5,969	5,472
1/5/11	64	64	5,688	5,926
1/6/11	69	69	5,511	6,259
1/7/11	72	72	6,249	6,502
1/8/11	70	70	6,002	6,398
1/9/11	69	69	5,617	6,317
1/10/11	53	53	5,288	5,011
1/11/11	58	58	5,634	5,432
1/12/11	57	57	5,779	5,300
1/13/11	58	58	5,602	5,388
1/14/11	62	62	5,593	5,724
1/15/11	71	71	6,064	6,426
1/16/11	69	69	5,671	6,312
1/17/11	65	65	6,171	5,952
1/18/11	71	71	6,966	6,454
1/19/11	67	67	6,657	6,125
1/20/11	92	92	7,757	8,130
1/21/11	83	83	7,389	7,382
1/22/11	79	79	7,012	7,091
1/23/11	64	64	6,004	5,875
1/24/11	56	56	5,793	5,215
1/25/11	51	51	5,145	4,829
1/26/11	51	51	4,539	4,845
1/27/11	49	49	4,222	4,678
1/28/11	48	48	4,487	4,621
1/29/11	62	62	5,750	5,693
1/30/11	64	64	5,705	5,856
1/31/11	75	75	6,466	6,760
2/1/11	73	73	7,237	6,643
2/2/11	69	69	6,664	6,323
2/3/11	47	47	5,014	4,518
2/4/11	40	40	4,057	3,990
2/5/11	37	37	3,915	3,708
2/6/11	58	58	5,399	5,390
2/7/11	78	78	7,166	6,989
2/8/11	75	75	7,057	6,787
2/9/11	81	81	7,196	7,274
2/10/11	69	69	6,758	6,317
2/11/11	48	48	4,871	4,640
2/12/11	35	35	3,625	3,593
2/13/11	30	30	3,423	3,181
2/14/11	31	31	3,512	3,232
2/15/11	30	30	3,402	3,187
2/16/11	21	21	3,115	2,410
2/17/11	49	49	4,718	4,671
2/18/11	68	68	5,780	6,185
2/19/11	58	58	5,370	5,434
2/20/11	58	58	5,266	5,419
2/21/11	49	49	4,861	4,669
2/22/11	48	48	4,862	4,586
2/23/11	56	56	5,238	5,261
2/24/11	71	71	6,321	6,418
2/25/11	78	78	6,952	7,008
2/26/11	70	70	6,326	6,332
2/27/11	62	62	5,469	5,738
2/28/11	49	49	5,115	4,692
3/1/11	69	69	6,888	6,282
3/2/11	67	67	6,252	6,110
3/3/11	47	47	4,813	4,548
3/4/11	60	60	5,665	5,606
3/5/11	55	55	4,760	5,178
3/6/11	50	50	4,666	4,800
3/7/11	60	60	5,195	5,594
3/8/11	50	50	4,217	4,762
3/9/11	41	41	4,237	4,075
3/10/11	40	40	4,230	3,935
3/11/11	44	44	4,356	4,290
3/12/11	61	61	5,735	5,650
3/13/11	47	47	4,638	4,548
3/14/11	34	34	3,649	3,471
3/15/11	30	30	3,173	3,142
3/16/11	27	27	2,823	2,928
3/17/11	36	36	3,494	3,620
3/18/11	42	42	3,699	4,160
3/19/11	36	36	3,134	3,610
3/20/11	31	31	3,189	3,254
3/21/11	29	29	3,353	3,098
3/22/11	46	46	4,429	4,446
3/23/11	48	48	4,508	4,570
3/24/11	43	43	4,396	4,229
3/25/11	42	42	4,118	4,160
3/26/11	45	45	3,991	4,346
3/27/11	44	44	4,029	4,277
3/28/11	40	40	4,192	3,950
3/29/11	35	35	3,789	3,542
3/30/11	32	32	3,685	3,312
3/31/11	30	30	3,520	3,142
4/1/11	31	31	3,056	3,232
4/2/11	25	25	2,483	2,774
4/3/11	34	34	3,031	3,521

4/4/11	36	36	3,456	3,610
4/5/11	27	27	2,938	2,931
4/6/11	26	26	2,664	2,848
4/7/11	19	19	2,388	2,280
4/8/11	11	11	1,703	1,616
4/9/11	14	14	1,696	1,860
4/10/11	27	27	2,596	2,938
4/11/11	17	17	2,130	2,163
4/12/11	16	16	1,836	2,011
4/13/11	37	37	2,915	3,725
4/14/11	31	31	3,092	3,274
4/15/11	32	32	3,423	3,343
4/16/11	40	40	3,296	3,932
4/17/11	35	35	2,750	3,566
4/18/11	36	36	3,180	3,677
4/19/11	28	28	2,830	2,973
4/20/11	31	31	3,141	3,264
4/21/11	24	24	2,969	2,722
4/22/11	27	27	2,910	2,948
4/23/11	21	21	2,339	2,480
4/24/11	14	14	1,728	1,912
4/25/11	10	10	1,530	1,600
4/26/11	20	20	2,074	2,366
4/27/11	21	21	2,418	2,470
4/28/11	19	19	1,922	2,266
4/29/11	8	8	1,529	1,423
4/30/11	30	30	2,597	3,160
5/1/11	41	41	3,540	4,044
5/2/11	28	28	2,866	2,973
5/3/11	15	15	2,004	1,955
5/4/11	12	12	1,937	1,736
5/5/11	17	17	1,780	2,138
5/6/11	9	9	1,260	1,524
5/7/11	9	9	1,152	1,459
5/8/11	9	9	1,448	1,485
5/9/11	11	11	1,439	1,648
5/10/11	3	3	1,222	1,032
5/11/11	11	11	1,368	1,664
5/12/11	20	20	2,000	2,352
5/13/11	23	23	2,097	2,616
5/14/11	13	13	1,776	1,834
5/15/11	17	17	1,182	2,125
5/16/11	12	12	1,268	1,766
5/17/11	11	11	1,168	1,624
5/18/11	2	2	1,043	938
5/19/11	0	0	996	768
5/20/11	0	0	922	768
5/21/11	8	8	859	1,378
5/22/11	2	2	854	941
5/23/11	10	10	1,122	1,553
5/24/11	19	19	1,248	2,280
5/25/11	18	18	1,305	2,176
5/26/11	12	12	1,198	1,718
5/27/11	15	15	1,258	2,000
5/28/11	12	12	929	1,710
5/29/11	8	8	770	1,440
5/30/11	3	3	691	1,039
5/31/11	12	12	1,237	1,728
6/1/11	9	9	1,021	1,478
6/2/11	1	1	894	862
6/3/11	0	0	769	768
6/4/11	10	10	670	1,538
6/5/11	0	0	628	768
6/6/11	0	0	817	768
6/7/11	0	0	861	768
6/8/11	15	15	1,073	1,989
6/9/11	9	9	1,054	1,453
6/10/11	14	14	995	1,860
6/11/11	8	8	751	1,427
6/12/11	4	4	842	1,123
6/13/11	0	0	982	768
6/14/11	0	0	954	768
6/15/11	6	6	998	1,272
6/16/11	2	2	986	934
6/17/11	0	0	789	768
6/18/11	0	0	665	768
6/19/11	1	1	665	854
6/20/11	2	2	908	944
6/21/11	7	7	993	1,306
6/22/11	10	10	1,033	1,560
6/23/11	6	6	955	1,277
6/24/11	0	0	783	768
6/25/11	0	0	617	768
6/26/11	1	1	666	854
6/27/11	6	6	920	1,286
6/28/11	4	4	862	1,098
6/29/11	0	0	768	768
6/30/11	0	0	723	768
Totals	10,055	10,055	1,019,019	1,084,693

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

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

MINNESOTA ENERGY RESOURCES - PNG

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

Rate Class	Tariff Rate Designation	Jul-10 Average Customers	Aug-10 Average Customers	Sep-10 Average Customers	Oct-10 Average Customers	Nov-10 Average Customers	Dec-10 Average Customers	Jan-11 Average Customers	Feb-11 Average Customers	Mar-11 Average Customers	Apr-11 Average Customers	May-11 Average Customers	Jun-11 Average Customers
Residential w/ Heat	MN004	3,774	3,782	3,790	3,822	3,869	3,915						
Residential w/o Heat	MN003	68	72	73	73	73	73						
Commercial-SV	MN051/072	326	323	323	323	320	334						
Commercial-LV	MN073	7	7	8	8	8	8						
Industrial-SV	MN058	0	0	0	0	0	1						
Industrial-LV	MN061	361	366	364	361	363	371						
SV-Interruptible	MN105/126	26	23	24	24	24	16						
LV-Interruptible	MN223	0	0	1	1	1	1						
Transport	MN/586/MN70A/76A	1	1	4	5	5	5						

MINNESOTA ENERGY RESOURCES - PNG

Projected Fixed Cost - November 2011 through March 2012

Futures Contracts WACOG

VGT

Nov-11 (30)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/31/11	4,304	$ 4.8940	$ 21,063	$ 3.4860	$ 15,003	$ 6,060
06/16/11	4,051	$ 4.6510	$ 18,839	$ 3.4860	$ 14,121	$ 4,719
07/25/11	3,544	$ 4.4700	$ 15,843	$ 3.4860	$ 12,355	$ 3,488
08/02/11	3,038	$ 4.2550	$ 12,927	$ 3.4860	$ 10,590	$ 2,336
09/21/11	2,532	$ 3.8260	$ 9,686	$ 3.4860	$ 8,825	$ 861
10/03/11	2,532	$ 3.6160	$ 9,154	$ 3.4860	$ 8,825	$ 329
Total	20,000		$ 87,512		$ 69,720	$ 17,792
WACOG			$ 4.3756		$ 3.4860	$ 0.8896

Dec-11 (31)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/31/11	4,889	$ 5.0870	$ 24,870	$ 3.9515	$ 19,318	$ 5,551
06/16/11	3,556	$ 4.8410	$ 17,212	$ 3.9515	$ 14,050	$ 3,163
06/16/11	1,333	$ 4.8420	$ 6,456	$ 3.9515	$ 5,269	$ 1,187
07/07/11	3,556	$ 4.5500	$ 16,178	$ 3.9515	$ 14,050	$ 2,128
08/04/11	2,222	$ 4.2840	$ 9,520	$ 3.9515	$ 8,781	$ 739
09/19/11	2,222	$ 4.1800	$ 9,289	$ 3.9515	$ 8,781	$ 508
10/05/11	2,222	$ 3.9080	$ 8,684	$ 3.9515	$ 8,781	$ (97)
	20,000		$ 92,209		$ 79,030	$ 13,179
			$ 4.6105		$ 3.9515	$ 0.6590

Jan-12 (31)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/26/11	4,058	$ 4.9410	$ 20,050	$ 4.0160	$ 16,297	$ 3,754
06/22/11	4,058	$ 4.8580	$ 19,714	$ 4.0160	$ 16,297	$ 3,417
07/21/11	3,768	$ 4.7690	$ 17,970	$ 4.0160	$ 15,133	$ 2,837
08/16/11	1,739	$ 4.4320	$ 7,708	$ 4.0160	$ 6,984	$ 723
08/16/11	1,449	$ 4.4330	$ 6,425	$ 4.0160	$ 5,820	$ 604
09/15/11	2,609	$ 4.3300	$ 11,296	$ 4.0160	$ 10,477	$ 819
10/20/11	2,319	$ 3.9670	$ 9,199	$ 4.0160	$ 9,312	$ (114)
	20,000		$ 92,361		$ 80,320	$ 12,041
			$ 4.6181		$ 4.0160	$ 0.6021

Feb-12 (29)						
Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/26/11	2,778	$ 4.9000	$ 13,611	$ 4.0365	$ 11,212	$ 2,399
06/30/11	2,222	$ 4.8300	$ 10,733	$ 4.0365	$ 8,970	$ 1,763
07/07/11	833	$ 4.6580	$ 3,882	$ 4.0365	$ 3,364	$ 518
07/07/11	1,111	$ 4.6620	$ 5,180	$ 4.0365	$ 4,485	$ 695
08/25/11	1,111	$ 4.3340	$ 4,816	$ 4.0365	$ 4,485	$ 331
09/16/11	1,111	$ 4.3140	$ 4,793	$ 4.0365	$ 4,485	$ 308
10/06/11	833	$ 4.1000	$ 3,417	$ 4.0365	$ 3,364	$ 53
Total	10,000		$ 46,432		$ 40,365	$ 6,067
WACOG			$ 4.6432		$ 4.0365	$ 0.6067

Mar-12 (31)						
Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/19/11	5,934	$ 4.7660	$ 28,282	$ 3.9580	$ 23,487	$ 4,795
06/23/11	1,978	$ 4.6590	$ 9,216	$ 3.9580	$ 7,829	$ 1,387
06/23/11	3,956	$ 4.6600	$ 18,435	$ 3.9580	$ 15,658	$ 2,777
07/27/11	5,934	$ 4.6700	$ 27,712	$ 3.9580	$ 23,487	$ 4,225
08/29/11	4,615	$ 4.2840	$ 19,772	$ 3.9580	$ 18,268	$ 1,505
09/22/11	3,956	$ 4.1800	$ 16,536	$ 3.9580	$ 15,658	$ 878
10/21/11	3,626	$ 3.9250	$ 14,234	$ 3.9580	$ 14,353	$ (120)
	30,000		$ 134,187		$ 118,740	$ 15,447
			$ 4.4729		$ 3.9580	$ 0.5149

Total						
	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
	21,963	$ 4.9118	$ 107,876	$ 3.8847	$ 85,318	$ 22,558
	15,864	$ 4.7726	$ 75,715	$ 3.8619	$ 61,266	$ 14,448
	13,435	$ 4.6584	$ 62,586	$ 3.8540	$ 51,779	$ 10,807
	15,378	$ 4.5328	$ 69,704	$ 3.8755	$ 59,597	$ 10,108
	11,930	$ 4.2096	$ 50,219	$ 3.8710	$ 46,179	$ 4,039
	12,430	$ 4.1086	$ 51,069	$ 3.8799	$ 48,226	$ 2,843
	9,001	$ 3.9478	$ 35,533	$ 3.9786	$ 35,811	$ (277)
	100,000		$ 452,701		$ 388,175	$ 64,526
			$ 4.5270		$ 3.8817	$ 0.6453

MINNESOTA ENERGY RESOURCES - PNG

Projected Storage Cost - November 2011 through March 2012

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

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

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

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

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

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

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

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

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-11

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/31/11		14	140,000	$ 5.0000	$ 700,000	$ 3.5310	$ 494,340	$ 3.5310	$ 494,340	$ -	$ 0.3750	$ 52,500	$ 546,840
2	06/23/11		15	150,000	$ 4.5000	$ 675,000	$ 3.5310	$ 529,650	$ 3.5310	$ 529,650	$ -	$ 0.3350	$ 50,250	$ 579,900
3	07/21/11		16	160,000	$ 4.5000	$ 720,000	$ 3.5310	$ 564,960	$ 3.5310	$ 564,960	$ -	$ 0.3000	$ 48,000	$ 612,960
4	08/31/11		20	200,000	$ 4.5000	$ 900,000	$ 3.5310	$ 706,200	$ 3.5310	$ 706,200	$ -	$ 0.1030	$ 20,600	$ 726,800
5	09/15/11		20	200,000	$ 4.0000	$ 800,000	$ 3.5310	$ 706,200	$ 3.5310	$ 706,200	$ -	$ 0.1700	$ 34,000	$ 740,200
6	10/04/11		19	190,000	$ 4.0000	$ 760,000	$ 3.5310	$ 670,890	$ 3.5310	$ 670,890	$ -	$ 0.0230	$ 4,370	$ 675,260
7				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
Total			104	1,040,000		$ 4,555,000		$ 3,672,240		$ 3,672,240	$ -		$ 209,720	$ 3,881,960
						$ 4.3798		$ 3.5310		$ 3.5310	$ -		$ 0.2017	$ 3.7327
NNG-PNG	76	73.08%	76	760,000	$ 4.3798	$ 3,328,654	$ 3.5310	$ 2,683,560	$ 3.5310	$ 2,683,560	$ -	$ 0.2017	$ 153,257	$ 2,836,817
NNG-NMU	9	8.65%	9	90,000	$ 4.3798	$ 394,183	$ 3.5310	$ 317,790	$ 3.5310	$ 317,790	$ -	$ 0.2017	$ 18,149	$ 335,939
GLGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5310	$ 105,930	$ 3.5310	$ 105,930	$ -	$ 0.2017	$ 6,050	$ 111,980
GLGT-NMU	5	4.81%	5	50,000	$ 4.3798	$ 218,990	$ 3.5310	$ 176,550	$ 3.5310	$ 176,550	$ -	$ 0.2017	$ 10,083	$ 186,633
VGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5310	$ 105,930	$ 3.5310	$ 105,930	$ -	$ 0.2017	$ 6,050	$ 111,980
VGT-NMU	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5310	$ 141,240	$ 3.5310	$ 141,240	$ -	$ 0.2017	$ 8,066	$ 149,306
Centra	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5310	$ 141,240	$ 3.5310	$ 141,240	$ -	$ 0.2017	$ 8,066	$ 149,306
Total	104	100.0%	104	1,040,000	$ 4.3798	$ 4,555,000	$ 3.5310	$ 3,672,240	$ 3.5310	$ 3,672,240	$ -	$ 0.2017	$ 209,720	$ 3,881,960
														$ 3.7327

Dec-11

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/31/11		22	220,000	$ 5.5000	$ 1,210,000	$ 3.8140	$ 839,080	$ 3.8140	$ 839,080	$ -	$ 0.2880	$ 63,360	$ 902,440
2	06/30/11		22	220,000	$ 5.0000	$ 1,100,000	$ 3.8140	$ 839,080	$ 3.8140	$ 839,080	$ -	$ 0.2750	$ 60,500	$ 899,580
3	07/25/11		21	210,000	$ 5.0000	$ 1,050,000	$ 3.8140	$ 800,940	$ 3.8140	$ 800,940	$ -	$ 0.1980	$ 41,580	$ 842,520
4	08/03/11		25	250,000	$ 4.5000	$ 1,125,000	$ 3.8140	$ 953,500	$ 3.8140	$ 953,500	$ -	$ 0.2670	$ 66,750	$ 1,020,250
5	09/23/11		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8140	$ 953,500	$ 3.8140	$ 953,500	$ -	$ 0.2180	$ 54,500	$ 1,008,000
6	10/07/11		28	280,000	$ 4.0000	$ 1,120,000	$ 3.8140	$ 1,067,920	$ 3.8140	$ 1,067,920	$ -	$ 0.1100	$ 30,800	$ 1,098,720
7				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
Total			143	1,430,000		$ 6,605,000		$ 5,454,920		$ 5,454,920	$ -		$ 317,490	$ 5,771,510
						$ 4.6189		$ 3.8140		$ 3.8140	$ -		$ 0.2220	$ 4.0360
NNG-PNG	105	73.43%	105	1,050,000	$ 4.6189	$ 4,849,825	$ 3.8140	$ 4,004,700	$ 3.8140	$ 4,004,700	$ -	$ 0.2220	$ 233,122	$ 4,237,822
NNG-NMU	13	9.09%	13	130,000	$ 4.6189	$ 600,455	$ 3.8140	$ 495,820	$ 3.8140	$ 495,820	$ -	$ 0.2220	$ 28,863	$ 524,683
GLGT-PNG	4	2.80%	4	40,000	$ 4.6189	$ 184,755	$ 3.8140	$ 152,560	$ 3.8140	$ 152,560	$ -	$ 0.2220	$ 8,881	$ 161,441
GLGT-NMU	7	4.90%	7	70,000	$ 4.6189	$ 323,322	$ 3.8140	$ 266,980	$ 3.8140	$ 266,980	$ -	$ 0.2220	$ 15,541	$ 282,521
VGT-PNG	3	2.10%	3	30,000	$ 4.6189	$ 138,566	$ 3.8140	$ 114,420	$ 3.8140	$ 114,420	$ -	$ 0.2220	$ 6,661	$ 121,081
VGT-NMU	6	4.20%	6	60,000	$ 4.6189	$ 277,133	$ 3.8140	$ 228,840	$ 3.8140	$ 228,840	$ -	$ 0.2220	$ 13,321	$ 242,161
Centra	5	3.50%	5	50,000	$ 4.6189	$ 230,944	$ 3.8140	$ 190,700	$ 3.8140	$ 190,700	$ -	$ 0.2220	$ 11,101	$ 201,801
Total	143	100.0%	143	1,430,000	$ 4.6189	$ 6,605,000	$ 3.8140	$ 5,454,920	$ 3.8140	$ 5,454,920	$ -	$ 0.2220	$ 317,490	$ 5,771,510
														$ 4.0360

Jan-12

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/27/11		21	210,000	$ 5.5000	$ 1,155,000	$ 3.9710	$ 833,910	$ 3.9710	$ 833,910	$ -	$ 0.3150	$ 66,150	$ 900,060
2	06/17/11		25	250,000	$ 5.0000	$ 1,250,000	$ 3.9710	$ 992,750	$ 3.9710	$ 992,750	$ -	$ 0.3900	$ 97,500	$ 1,090,250
3	07/26/11		27	270,000	$ 5.0000	$ 1,350,000	$ 3.9710	$ 1,072,170	$ 3.9710	$ 1,072,170	$ -	$ 0.2600	$ 70,200	$ 1,142,370
4	08/31/11		28	280,000	$ 4.5000	$ 1,260,000	$ 3.9710	$ 1,111,880	$ 3.9710	$ 1,111,880	$ -	$ 0.3150	$ 88,200	$ 1,200,080
5	09/29/11		30	300,000	$ 4.5000	$ 1,350,000	$ 3.9710	$ 1,191,300	$ 3.9710	$ 1,191,300	$ -	$ 0.1390	$ 41,700	$ 1,233,000
6	10/19/11		31	310,000	$ 4.0000	$ 1,240,000	$ 3.9710	$ 1,231,010	$ 3.9710	$ 1,231,010	$ -	$ 0.2050	$ 63,550	$ 1,294,560
7				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
Total	Total		162	1,620,000		$ 7,605,000		$ 6,433,020		$ 6,433,020	$ -		$ 427,300	$ 6,860,320
						$ 4.6944		$ 3.9710		$ 3.9710	$ -		$ 0.2638	$ 4.2348
NNG-PNG	117	72.22%	117	1,170,000	$ 4.6944	$ 5,492,500	$ 3.9710	$ 4,646,070	$ 3.9710	$ 4,646,070	$ -	$ 0.2638	$ 308,606	$ 4,954,676
NNG-NMU	15	9.26%	15	150,000	$ 4.6944	$ 704,167	$ 3.9710	$ 595,650	$ 3.9710	$ 595,650	$ -	$ 0.2638	$ 39,565	$ 635,215
GLGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 3.9710	$ 158,840	$ 3.9710	$ 158,840	$ -	$ 0.2638	$ 10,551	$ 169,391
GLGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 3.9710	$ 317,680	$ 3.9710	$ 317,680	$ -	$ 0.2638	$ 21,101	$ 338,781
VGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 3.9710	$ 158,840	$ 3.9710	$ 158,840	$ -	$ 0.2638	$ 10,551	$ 169,391
VGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 3.9710	$ 317,680	$ 3.9710	$ 317,680	$ -	$ 0.2638	$ 21,101	$ 338,781
Centra	6	3.70%	6	60,000	$ 4.6944	$ 281,667	$ 3.9710	$ 238,260	$ 3.9710	$ 238,260	$ -	$ 0.2638	$ 15,826	$ 254,086
Total	162	100.0%	162	1,620,000	$ 4.6944	$ 7,605,000	$ 3.9710	$ 6,433,020	$ 3.9710	$ 6,433,020	$ -	$ 0.2638	$ 427,300	$ 6,860,320
														$ 4.2348

Feb-12

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/27/11		20	200,000	$ 5.5000	$ 1,100,000	$ 3.9890	$ 797,800	$ 3.9890	$ 797,800	$ -	$ 0.3250	$ 65,000	$ 862,800
2	06/17/11		21	210,000	$ 5.0000	$ 1,050,000	$ 3.9890	$ 837,690	$ 3.9890	$ 837,690	$ -	$ 0.4080	$ 85,680	$ 923,370
3	07/27/11		23	230,000	$ 5.0000	$ 1,150,000	$ 3.9890	$ 917,470	$ 3.9890	$ 917,470	$ -	$ 0.3000	$ 69,000	$ 986,470
4	08/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 3.9890	$ 957,360	$ 3.9890	$ 957,360	$ -	$ 0.2740	$ 65,760	$ 1,023,120
5	09/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 3.9890	$ 957,360	$ 3.9890	$ 957,360	$ -	$ 0.1620	$ 38,880	$ 996,240
6	10/19/11		27	270,000	$ 4.0000	$ 1,080,000	$ 3.9890	$ 1,077,030	$ 3.9890	$ 1,077,030	$ -	$ 0.2650	$ 71,550	$ 1,148,580
7				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
Total			139	1,390,000		$ 6,540,000		$ 5,544,710		$ 5,544,710	$ -		$ 395,970	$ 5,940,580
						$ 4.7050		$ 3.9890		$ 3.9890	$ -		$ 0.2848	$ 4.2738
NNG-PNG	99	71.22%	99	990,000	$ 4.7050	$ 4,657,956	$ 3.9890	$ 3,949,110	$ 3.9890	$ 3,949,110	$ -	$ 0.2848	$ 281,951	$ 4,231,061
NNG-NMU	13	9.35%	13	130,000	$ 4.7050	$ 611,655	$ 3.9890	$ 518,570	$ 3.9890	$ 518,570	$ -	$ 0.2848	$ 37,024	$ 555,594
GLGT-PNG	4	2.88%	4	40,000	$ 4.7050	$ 188,201	$ 3.9890	$ 159,560	$ 3.9890	$ 159,560	$ -	$ 0.2848	$ 11,392	$ 170,952
GLGT-NMU	7	5.04%	7	70,000	$ 4.7050	$ 329,353	$ 3.9890	$ 279,230	$ 3.9890	$ 279,230	$ -	$ 0.2848	$ 19,936	$ 299,166
VGT-PNG	4	2.88%	4	40,000	$ 4.7050	$ 188,201	$ 3.9890	$ 159,560	$ 3.9890	$ 159,560	$ -	$ 0.2848	$ 11,392	$ 170,952
VGT-NMU	7	5.04%	7	70,000	$ 4.7050	$ 329,353	$ 3.9890	$ 279,230	$ 3.9890	$ 279,230	$ -	$ 0.2848	$ 19,936	$ 299,166
Centra	5	3.60%	5	50,000	$ 4.7050	$ 235,252	$ 3.9890	$ 199,450	$ 3.9890	$ 199,450	$ -	$ 0.2848	$ 14,240	$ 213,690
Total	139	100.0%	139	1,390,000	$ 4.7050	$ 6,540,000	$ 3.9890	$ 5,544,710	$ 3.9890	$ 5,544,710	$ -	$ 0.2848	$ 395,970	$ 5,940,580
														$ 4.2738

Mar-12

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/27/11		14	140,000	$ 5.5000	$ 770,000	$ 3.9530	$ 553,420	$ 3.9530	$ 553,420	$ -	$ 0.3450	$ 48,300	$ 601,720
2	06/30/11		17	170,000	$ 5.0000	$ 850,000	$ 3.9530	$ 672,010	$ 3.9530	$ 672,010	$ -	$ 0.3900	$ 66,300	$ 738,310
3	07/26/11		18	180,000	$ 5.0000	$ 900,000	$ 3.9530	$ 711,540	$ 3.9530	$ 711,540	$ -	$ 0.3100	$ 55,800	$ 767,340
4	08/24/11		21	210,000	$ 4.5000	$ 945,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.2800	$ 58,800	$ 888,930
5	09/28/11		21	210,000	$ 4.5000	$ 945,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.2100	$ 44,100	$ 874,230
6	10/17/11		21	210,000	$ 4.0000	$ 840,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.3290	$ 69,090	$ 899,220
7				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
Total			112	1,120,000		$ 5,250,000		$ 4,427,360		$ 4,427,360	$ -		$ 342,390	$ 4,769,750
						$ 4.6875		$ 3.9530		$ 3.9530	$ -		$ 0.3057	$ 4.2587
NNG-PNG	82	73.21%	82	820,000	$ 4.6875	$ 3,843,750	$ 3.9530	$ 3,241,460	$ 3.9530	$ 3,241,460	$ -	$ 0.3057	$ 250,678	$ 3,492,138
NNG-NMU	10	8.93%	10	100,000	$ 4.6875	$ 468,750	$ 3.9530	$ 395,300	$ 3.9530	$ 395,300	$ -	$ 0.3057	$ 30,571	$ 425,871
GLGT-PNG	3	2.68%	3	30,000	$ 4.6875	$ 140,625	$ 3.9530	$ 118,590	$ 3.9530	$ 118,590	$ -	$ 0.3057	$ 9,171	$ 127,761
GLGT-NMU	5	4.46%	5	50,000	$ 4.6875	$ 234,375	$ 3.9530	$ 197,650	$ 3.9530	$ 197,650	$ -	$ 0.3057	$ 15,285	$ 212,935
VGT-PNG	3	2.68%	3	30,000	$ 4.6875	$ 140,625	$ 3.9530	$ 118,590	$ 3.9530	$ 118,590	$ -	$ 0.3057	$ 9,171	$ 127,761
VGT-NMU	5	4.46%	5	50,000	$ 4.6875	$ 234,375	$ 3.9530	$ 197,650	$ 3.9530	$ 197,650	$ -	$ 0.3057	$ 15,285	$ 212,935
Centra	4	3.57%	4	40,000	$ 4.6875	$ 187,500	$ 3.9530	$ 158,120	$ 3.9530	$ 158,120	$ -	$ 0.3057	$ 12,228	$ 170,348
Total	112	100.0%	112	1,120,000	$ 4.6875	$ 5,250,000	$ 3.9530	$ 4,427,360	$ 3.9530	$ 4,427,360	$ -	$ 0.3057	$ 342,390	$ 4,769,750
														$ 4.2587

Total

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			91	910,000	$ 5.4231	$ 4,935,000	$ 3.8665	$ 3,518,550	$ 3.8665	$ 3,518,550	$ -	$ 0.3245	$ 295,310	$ 3,813,860
2			100	1,000,000	$ 4.9250	$ 4,925,000	$ 3.8712	$ 3,871,180	$ 3.8712	$ 3,871,180	$ -	$ 0.3602	$ 360,230	$ 4,231,410
3			105	1,050,000	$ 4.9238	$ 5,170,000	$ 3.8734	$ 4,067,080	$ 3.8734	$ 4,067,080	$ -	$ 0.2710	$ 284,580	$ 4,351,660
4			118	1,180,000	$ 4.5000	$ 5,310,000	$ 3.8636	$ 4,559,070	$ 3.8636	$ 4,559,070	$ -	$ 0.2543	$ 300,110	$ 4,859,180
5			120	1,200,000	$ 4.3125	$ 5,175,000	$ 3.8654	$ 4,638,490	$ 3.8654	$ 4,638,490	$ -	$ 0.1777	$ 213,180	$ 4,851,670
6			126	1,260,000	$ 4.0000	$ 5,040,000	$ 3.8706	$ 4,876,980	$ 3.8706	$ 4,876,980	$ -	$ 0.1900	$ 239,360	$ 5,116,340
7														
8														
9														
10														
Total			660	6,600,000		$ 30,555,000		$ 25,531,350		$ 25,531,350	$ -		$ 1,692,770	$ 27,224,120
						$ 4.6295		$ 3.8684		$ 3.8684	$ -		$ 0.2565	$ 4.1249
NNG-PNG	479	72.58%	479	4,790,000	$ 4.6295	$ 22,175,523	$ 3.8684	$ 18,529,571	$ 3.8684	$ 18,529,571	$ -	$ 0.2565	$ 1,228,541	$ 19,758,111
NNG-NMU	60	9.09%	60	600,000	$ 4.6295	$ 2,777,727	$ 3.8684	$ 2,321,032	$ 3.8684	$ 2,321,032	$ -	$ 0.2565	$ 153,888	$ 2,474,920
GLGT-PNG	18	2.73%	18	180,000	$ 4.6295	$ 833,318	$ 3.8684	$ 696,310	$ 3.8684	$ 696,310	$ -	$ 0.2565	$ 46,166	$ 742,476
GLGT-NMU	32	4.85%	32	320,000	$ 4.6295	$ 1,481,455	$ 3.8684	$ 1,237,884	$ 3.8684	$ 1,237,884	$ -	$ 0.2565	$ 82,074	$ 1,319,957
VGT-PNG	17	2.58%	17	170,000	$ 4.6295	$ 787,023	$ 3.8684	$ 657,626	$ 3.8684	$ 657,626	$ -	$ 0.2565	$ 43,602	$ 701,227
VGT-NMU	30	4.55%	30	300,000	$ 4.6295	$ 1,388,864	$ 3.8684	$ 1,160,516	$ 3.8684	$ 1,160,516	$ -	$ 0.2565	$ 76,944	$ 1,237,460
Centra	24	3.64%	24	240,000	$ 4.6295	$ 1,111,091	$ 3.8684	$ 928,413	$ 3.8684	$ 928,413	$ -	$ 0.2565	$ 61,555	$ 989,968
Total	660	100.0%	660	6,600,000	$ 4.6295	$ 30,555,000	$ 3.8684	$ 25,531,350	$ 3.8684	$ 25,531,350	$ -	$ 0.2565	$ 1,692,770	$ 27,224,120
														$ 4.1249