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November 1, 2010

VIA ELECTRONIC FILING

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

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–NMU for Approval of a Change in Demand Entitlement;
Docket No. ___________________

Dear Dr. Haar:

In accordance with Minnesota Rule 7825.2910, subpart 2, please find the public and nonpublic versions of Minnesota Energy Resources Corporation's (MERC) request to change demand entitlement.

Please note that Attachments 5 and 9 contain financial information with independent economic value that is not generally known to, and not readily ascertainable by, competitors of MERC, who could obtain economic value from its disclosure. MERC maintains this information as secret. Accordingly this data qualifies as trade secret data as defined in Minn. Stat. § 13.37, subd. 1(b), and MERC requests that the data be treated as trade secret information.

In accordance with Minnesota Rule 7825.2910, subpart 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

Please feel free to contact me at (612) 340-2881 if you have any questions regarding this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

November 1, 2010

To: Service List

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

Notice of Availability

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

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

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

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

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

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

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

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

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NMU (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2010.

STATE OF MINNESOTA
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In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – NMU for Approval of a	)	Docket No. _______________
Change in Demand Entitlement	)	

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NMU (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2010.

This filing includes the following attachments:

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

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

1. **Summary of Filing**

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

2. **Service**

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

3. **General Filing Information**

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

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

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

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

C. Date of the Filing and Proposed Effective Date

Date of filing: November 1, 2010
Proposed Effective Date: November 1, 2010

D. Statute Controlling Schedule for Processing the Filing

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

E. Utility Employee Responsible for the Filing

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

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

DATED: November 1, 2010

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy Resources Corporation

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
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In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – NMU for Approval of a	)	Docket No. _______________
Change in Demand Entitlement	)	

PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NMU (MERC or the Company), a division of Integrys Energy Group, Inc. (TEG), hereby petitions the Minnesota Public Utilities Commission (Commission) approve changes in demand entitlements for MERC-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2010.

II. DISCUSSION

A. MERC's NMU Design Day Requirements

MERC's 2010-2011 NMU design day requirements decreased 2,808 Mcf (or approximately 4.406 percent) from 63,726 Mcf to 60,918 Mcf.

Table 1: MERC's Proposed Reserve Margins
For the 2010-2011 Heating Season
NMU (NNG, GLGT, VGT & Centra)

	Reserve Margin 2010-2011 Heating Season	Reserve Margin 2009-2010 Heating Season	Change
NNG Zone E-F	24.55%	4.70%	19.85%

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

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

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity on Northern Natural Gas (NNG), which includes PNG and NMU is 261,675 Dth as calculated in Attachment 5 and Attachment 7 under the NNG-PNG Entitlement Allocation.

The difference between the total Design Day requirement and total Design Day capacity results in a 19.92% positive reserve margin.

Demand Entitlement increased due to 7,000 Dth that historically was allocated to NMU and PNG-VGT Demand Entitlements, but has been allocated to PNG-NNG and NMU in this filing. This capacity was rarely used by PNG-VGT, and the decision was made to allocate the demand cost to the customer base that benefits from the capacity which is PNG-NNG and NMU-NNG customers. MERC also changed the allocation process by allocating all NNG and LS Power capacity to PNG-NNG and NMU-NNG customers based upon the forecasted Design Day as calculated in Attachment 5. The change in allocation process was made to address the Office of Energy Security's (OES) concern of NMU-NNG customers having a negative reserve margin.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day requirement for NMU-Centra is 8,248 Mcf as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity for NMU-Centra is 9,858 Mcf as calculated in Attachment 4, page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 19.52% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day requirement for NMU-GLGT is 14,964 Dth as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity for NMU-GLGT is 20,046 Mcf as calculated in Attachment 4, age 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 33.96% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day requirement for NMU-VGT is 10,835 Dth as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity for NMU-VGT is 13,868 Mcf as calculated in Attachment 4, page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 27.99% positive reserve margin.

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

Peakday

Purpose

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

Background

MERC is composed of two service areas:

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

Which are served by four pipelines:

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

Four Petitions for Change in Demand are filed (one for each of PGA):

A. PNG customers served off of VGT = PNG-VGT

B. PNG customers served off of GLGT = PNG-GLGT

C. PNG customers served off of NNG = PNG-NNG

D. All NMU customers - served off NNG, GLGT, VGT & Centra = NMU

Weather data is obtained from seven weather stations:

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

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

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

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

Analytical Approach

Summary

1. Obtain daily weather data for each weather station as shown in Attachment 13
2. Obtain daily total throughput volumes by pipeline
3. Perform total throughput peak day regressions

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

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

6. Apply sales forecast growth rates

Detail

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

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

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

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

The Peak Day Process consisted of:

I. Data Preparation

II. Regression Generation of Net Daily Metered Volumes

III. Volume Risk Adjustments

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

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

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

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

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

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

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

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

- For each of the eight Demand Areas (Service Area / Pipeline):

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

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

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

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

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 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:

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

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

N. Maximum Daily Quantity (MDQ):

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

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

While interruptible, joint interruptible and transportation customer volumes were removed (as described above), in order to determine firm peak day load, daily firm capacity selections needed to be added back. The Sales and Revenue Forecasting department provided historical monthly DFC data for the "joint interruptible" customers from January 2009 through March 2010 that showed the volume that each customer has selected to receive as firm service from MERC each month. Based on direction from MERC Gas Supply, the Small Volume Joint Firm / Interruptible customers who were relying on MERC to provide peak day firm supply were identified and their the daily firm capacity volumes were summed by month for each demand area. The total volumes for January 2010 were then added back to the adjusted regression results.

C. Apply Sales Forecast Growth Rates

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

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

NMU-GLGT

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

NMU-VGT

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

PNG-NNG

Taconites / Direct Connects =

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

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

PNG-NNG

OSEU (End Users) =

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

B. Daily Firm Capacity

PNG-VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL
- BEST WESTERN

PNG-GLGT

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

PNG-NNG

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

Daily Design Day Estimate to Actual Comparison

In the 2007 demand entitlement dockets, MERC agreed to include a daily estimate utilizing the design day model which is calculated in Attachment 11, pages 1 through 4. The daily estimate is compared to actual consumption. The actual volumes are total through-put which includes interruptible and transportation volumes that are located behind MERC citygates. This does not include any transportation volumes that are directly connected with any interstate pipeline(s). 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 8,120 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 8,120 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 12.

C. <u>MERC's Specific NMU Proposed Demand-Related Changes</u>

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC's NMU customers during winter peak periods. The second type does not affect design day deliverability levels, but alters the capacity portfolio and the PGA costs recovered from customers.

1. Design Day Deliverability Changes

As shown in Attachment 3, MERC-PNG-NNG proposes to increase its approved total heating season entitlement by 8,036 Mcf/day (or approximately 12.60 percent). To obtain the proposed entitlement level, the Company proposes changes to its portfolio of capacity services identified below in Table 4. The increase was due to the Demand Entitlement increase of 7,000 Dth that historically was allocated to NMU and PNG-VGT Demand Entitlements, but has been allocated to PNG-NNG and NMU in this filing. This capacity was rarely used by PNG-VGT so the decision was made to allocate the demand cost to the customer base that benefits from the capacity which is PNG-NNG and NMU-NNG customers. MERC also changed the allocation process by allocating all NNG and LS Power capacity to PNG-NNG and NMU-NNG customers based upon the forecasted Design Day as calculated in Attachment 5. The change in allocation process was to address the OES's concern of NMU-NNG customers having a negative reserve margin.

MERC also purchased a Wadena Call Option on VGT for PNG-VGT and NMU (VGT) customers. The transaction allows MERC to call on gas up to 5,902 Dth/day from December 1, 2010 through February 28, 2011. The right to call on the gas costs $0.03 Dth for the 5,902 Dth/day call rights for the 90 day period (December 1, 2010 through February 28, 2011). The option substituted the need to contract for firm backhaul on VGT to meet the design day. The cost of VGT would have been approximately $66,700 compared to the $15,935 option cost.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)	
NNG TF12B & TF12V	(4,605)	Mcf/Day
NNG TF5	1,502	Mcf/Day
NNG TFX12	3,495	Mcf/Day
NNG TFX5	3,620	Mcf/Day
LS Power	424	Mcf/Day
NNG Subtotal	4,436	Mcf/Day
GLGT FT0016	0	Mcf/Day
GLGT FT0155 (5)	3,600	Mcf/Day
GLGT FT8466	0	Mcf/Day
VGT FA AF0012	0	Mcf/Day
VGT - Cap Release	0	Mcf/Day
VGT FT-A Backhaul	(5,902)	Mcf/Day
NNG-TF12 Base	(1,368)	Mcf/Day
NNG-TF12 Variable	(955)	Mcf/Day
NNG-TF5 Chisago	(563)	Mcf/Day
NNG-TFX 12 Chisago	(2,089)	Mcf/Day
NNG-TFX 5 Chisago	(926)	Mcf/Day
Wadena Delivered Option	5,902	Mcf/Day
Nexen PSO	0	Mcf/Day
Total Overall Change	8,036	Mcf/Day

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC-NMU proposes an increase in TFX Apr and TFX Oct and an increase of Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability. MERC also terminated the Nexen PSO and replaced it with AECO Storage. To deliver the supply from storage to MERC-NMU's markets, MERC entered in an AECO/Emerson swap. MERC sells gas at the storage point (AECO) to a supplier and buys an equivalent volume at Emerson/Spruce, which MERC then transports to its PNG-GLGT, PNG-VGT and NMU (GLGT, VGT and Centra) customers. The swap substituted the need to contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce. The cost of TCPL would have been approximately $758,222 compared to the $450,195 to swap the gas.

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

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2010/2011 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 $592,119 for the 2010/2011 winter. Please see Attachment 5.

iii. MERC entered into 149 contracts (10,000/contract) or 1,490,000. Total premium per contract is approximately $0.3974. 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 86 futures contracts (10,000/contract) or 860,000,

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 10, pages 1 through 4.

E. <u>Gas Supply.</u>

The NMU 2010-2011 Winter Portfolio Plans - Minnesota Energy Resources Corporation for NNG, GLGT, VGT and Centra gas supply purchases for the Hedging Plans is in Attachment 10 pages 5 and 6. This Attachment includes the projected sales number by month for the November 2010 through March 2011 period as well as the planned physical fixed price, financial call options and storage and/or exchange volumes by month.

F. <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 $4.9484. Please see Attachment 13, page 1 of 3. MERC is projecting the storage WACOG on NNG Storage and AECO Storage to be approximately $3.91. This is an estimate based upon the purchases in October but since this filing is being made before the accounting is closed for October, this estimate may change. Please see Attachment 13, page 2 of 3. The remaining 30% of the 70% is hedged by financial call options. MERC purchased call options at an average strike price of $5.01, which means if NYMEX contract(s) settle above that price, the options are exercised and MERC customers' gas cost is capped at the average strike price. Please see Attachment 13, page 3 of 3. Since financial options are paper only MERC purchases physical index supply to back the financial call options. MERC projects the gas costs to be approximately $4.35 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $5.01 strike price plus the physical index basis spread. If the NYMEX prices are below the average $5.01 strike price, the average natural gas cost for 70% of the normal winter volumes will be lower. The remaining 30% of normal winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium or margin costs.

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

MERC proposes to begin recovering the costs associated with the change in demand-related costs in it monthly PGA effective November 1, 2010. Rate impacts associated with this change can be found on Attachment 4, pages 1 through 3, and on page 1 of Attachment 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 4 through 6, and Attachment 7, page 2, illustrate the rate impact created by this shift in cost recovery.

II. CONCLUSION

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

DATED: November 1, 2010

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern

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Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

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

/s/ Sarah J. Sorenson

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

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

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PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-NMU

Demand Entitlement Schedules

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2010

Design Day Requirement		57,662
Total Peak Day Entitlement		71,819
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 2)	47,933
Firm Annual Throughput - Minnesota		6,596,733
No. of Firm Customers		40,400
Department Load Factor Calculation		37.71%

MINNESOTA ENERGY RESOURCES - NMU

MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2010
HDD

Pipeline Group	2008/09 Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	% of total load	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	2008/09 Customer Growth	Total
NNG										
Peak	17,729	103	2,495	238		29,075	4,482	24,593	-4.0%	23,615
Off Peak	17,729	55	2,495	238		17,629	2,892	14,737	-4.0%	14,151
VGT										
VGT	5,721	109	1,477	72		10,142	2,203	7,939	-4.0%	7,623
**VGT/GLGT	3,141	107	331	49	68.0%	4,116	772	3,344	-4.0%	3,212
Peak	8,862		1,808	121				11,283		10,835
VGT	5,721	57	1,477	72		6,420	1,422	4,998	-4.0%	4,800
VGT/GLGT	3,141	57	331	49	68.0%	2,443	498	1,945	-4.0%	1,867
Off Peak	8,862		1,808	121				6,943		6,667
GLGT										
**VGT/GLGT	3,141	107	331	49	32.0%	1,937	363	1,574	-4.0%	1,511
GLGT	8,180	106	788	135		17,335	3,325	14,010	-4.0%	13,453
Peak	11,321		1,119	184				15,584		14,964
VGT/GLGT	3,141	57	331	49	32.0%	1,149	234	915	-4.0%	879
GLGT	8,180	57	788	135		10,681	2,145	8,536	-4.0%	8,196
Off Peak	11,321		1,119	184				9,451		9,075
Centra										
Peak	5,629	107	1,324	85		11,620	3,030	8,590	-4.0%	8,248
Off Peak	5,629	57	1,324	85		7,365	1,955	5,410	-4.0%	5,196
Total NMU										
Peak	40,400		6,415	579		74,225	14,175	60,050	-4.0%	57,662
Off Peak	40,400		6,415	579		45,687	9,146	36,541	-4.0%	35,089

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.

**Dual Supplied

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND PER CUSTOMER
NOVEMBER 1, 2010

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
10/11	40,400	57,662	1.43
09/10	41,135	60,918	1.48
08/09	39,112	63,726	1.63
07/08	38,258	61,008	1.59
06/07	38,483	61,060	1.59
05/06	38,208	62,107	1.63
04/05	39,816	60,703	1.52

Attachment 2

MINNESOTA ENERGY RESOURCES - NMU

SUMMER/WINTER USAGE - Mcf
PROJECTED 12 MONTHS ENDING JUNE 2010

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	1,311,676	3,878,918	5,190,594
IS	535,969	870,170	1,406,139
Total	1,847,645	4,749,088	6,596,733

MINNESOTA ENERGY RESOURCES - NMU

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2010

Type of Capacity or Entitlement		Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
NNG TF 12 Base & Variable		12,756	(4,605)	8,151
NNG TF 5		1,991	1,502	3,493
NNG TFX 12		0	3,495	3,495
NNG TFX 5		6,139	3,620	9,759
LS Power		2,725	424	3,149
Bison *		0	5,411	5,411
NBPL *		0	5,411	5,411
Peak Capacity		0	0	0
NNG Offpeak TFX*		0	0	0
NNG Subtotal		23,611	4,436	28,047
GLGT FT	FT0016	10,130	0	10,130
GLGT FT (12)	FT0155	1,178	0	1,178
GLGT FT (5)	FT0155	2,138	3,600	5,738
GLGT FT	FT8466	3,000	0	3,000
VGT FT-A	AF0012	7,966	0	7,966
VGT - Cap. Release	RF0361	0	0	0
VGT FT-A (4)	AF0160	5,902	(5,902)	0
NNG-TF12 Base	112495	1,368	(1,368)	0
NNG-TF12 Variable	112495	955	(955)	0
NNG-TF5 Chisago	112495	563	(563)	0
NNG-TFX 12 Chisago	112486	2,089	(2,089)	0
NNG-TFX 5 Chisago	112486	926	(926)	0
Wadena Delivered Option		0	5,902	5,902
CENTRA FT-1		9,858	0	9,858
Nexen PSO		0	0	0
Total Entitlement		63,783	8,036	71,819
Forecasted Design Day-Adjusted		60,918	(3,256)	57,662
Capacity Surplus/Shortage		2,865	11,292	14,157
Reserve Margin		4.70%		24.55%

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

MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2010

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-08- Oct .08	Last Demand Change G011- M-09- Oct. 09	Most Recent PGA Oct. 2010	Current Proposal Effective Nov.1,2010	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:				**140**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	-71.37%	0.03%	$0.0010
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.2669	10.94%	11.15%	23.99%	$0.2451
Commodity Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2769	-39.28%	-47.02%	3.50%	$0.2461
Avg Annual Cost	$1,677.68	$1,401.47	$993.78	$984.31	$1,018.76	-39.28%	-47.02%	3.50%	$34.45
Effect of proposed commodity change on average annual bills:									$0.14
Effect of proposed demand change on average annual bills:									$34.31
2) Large General Service: Avg. Annual Use:				**6,917**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	-41.71%	0.03%	$0.0010
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.2669	10.94%	13.10%	23.99%	$0.2451
Commodity Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.3126	0.00%	0.00%	6.28%	$0.1367
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.4136	-38.13%	-25.94%	5.44%	$0.3828
Avg Annual Cost	$82,889.18	$69,242.63	$49,099.63	$48,632.04	$51,279.73	-38.13%	-25.94%	5.44%	$2,647.69
Effect of proposed commodity change on average annual bills:									$6.92
Effect of proposed demand change on average annual bills:									$1,695.21
3) SV Interruptible Service: Avg. Annual Use:				**6,333**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	-41.71%	0.03%	$0.0010
Commodity Margin	$1.0127	$1.0127	$1.0127	$0.9560	$0.9560	-5.60%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.5905	$4.7055	$4.7891	$4.7901	-49.80%	-36.89%	0.02%	$0.0010
Avg Annual Cost	$60,426.32	$48,070.64	$29,799.93	$30,329.37	$30,335.70	-49.80%	-36.89%	0.02%	$6.33
Effect of proposed commodity change on average annual bills:									$6.33
4) LV Interruptible Service: Avg. Annual Use:				**37,114**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	-41.71%	0.03%	$0.0010
Commodity Margin	$0.3395	$0.3395	$0.3395	$0.2846	$0.2846	-16.17%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$6.9173	$4.0323	$4.1177	$4.1187	-53.56%	-40.46%	0.02%	$0.0010
Avg Annual Cost	$329,138.09	$256,728.67	$149,654.78	$152,824.32	$152,861.43	-53.56%	-40.46%	0.02%	$37.11
Effect of proposed commodity change on average annual bills:									$37.11

Note: Average Annual Average based on NMU Annual Automatic Adjustment Report in
Docket No. E,G999/AA-09-896
*Implemented with Interim rates
**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

DEMAND									Cost/Ccf
Contract Type			**Monthly Entitlement**		**Rate**		**Contract**	**Rate Case Sales**	
Northern Natural Gas (NNG)		**Season**	**(Dth)**	**Months**	**($/Dth)**		**Costs**	**(therms)**	
TF12B (Max Rate)	112495	Annual	4,232	12	$7.5776	$	384,821	54,901,770	$0.00701
TF12V (Max Rate)	112495	Annual	3,919	12	$9.0926	$	427,607	54,901,770	$0.00779
TF5 (Max Rate)	112495	Winter	3,493	5	$15.1530	$	264,647	54,901,770	$0.00482
TF12B (Discount-Winter)	112495	Annual	0	12	$6.4818	$	-	54,901,770	$0.00000
TF5 (Discount-Winter)	112495	Winter	0	5	$7.6000	$	-	54,901,770	$0.00000
TFX5 (Discount)	112561	Winter	649	5	$4.5600	$	14,797	54,901,770	$0.00027
TFX12 (Max Rate)	112486	Annual	1,171	12	$9.6288	$	135,304	54,901,770	$0.00246
TFX Apr (Max Rate)	112486	Summer	216	1	$5.6830	$	1,228	54,901,770	$0.00002
TFX Oct (Max Rate)	112486	Summer	216	1	$5.6830	$	1,228	54,901,770	$0.00002
TFX5 (Max Rate)	112486	Winter	6,208	5	$15.1530	$	470,349	54,901,770	$0.00857
TFX5 (Discount)	112486	Winter	0	5	$13.8736	$	-	54,901,770	$0.00000
TFX5 (Discount)	112486	Winter	195	5	$7.6050	$	7,415	54,901,770	$0.00014
TFX12 (Discount)	111866	Annual	139	12	$4.8640	$	8,113	54,901,770	$0.00015
TFX12 (Discount)	111866	Annual	895	12	$5.4720	$	58,769	54,901,770	$0.00107
TFX12 (Discount)	111866	Annual	1,290	12	$2.2192	$	34,353	54,901,770	$0.00063
TFX5 (Discount)	111866	Winter	41	5	$4.8640	$	997	54,901,770	$0.00002
TFX5 (Discount)	111866	Winter	265	5	$5.4720	$	7,250	54,901,770	$0.00013
TFX5 (Discount)	111866	Winter	2,401	5	$15.1392	$	181,746	54,901,770	$0.00331
Bison	FT0003	Annual	5,411	10.5	$17.4800	$	993,135	54,901,770	$0.01809
NBPL	T8673F	Annual	5,411	10.5	$6.9920	$	397,254	54,901,770	$0.00724
LS Power		Winter	3,149	3	$4.3463	$	41,059	54,901,770	$0.00075
WINDOM		Annual	0	12	$0.0000	$	-	54,901,770	$0.00000
SMS	112521	Annual	2,454	12	$2.1800	$	64,197	54,901,770	$0.00117
FDD - Reservation	118657	Annual	8,164	12	$1.7140	$	167,917	54,901,770	$0.00306
FDD - Storage Cycle	118657	Annual	94,137	5	$0.3567	$	167,893	54,901,770	$0.00306
FDD - Reservation	118657	Annual	601	12	$3.3157	$	23,913	54,901,770	$0.00044
FDD - Storage Cycle	118657	Annual	6,926	5	$0.6901	$	23,898	54,901,770	$0.00044
FDD - Reservation	121292	Annual	751	12	$1.7140	$	15,447	54,901,770	$0.00028
FDD - Storage Cycle	121292	Annual	8,658	5	$0.3567	$	15,442	54,901,770	$0.00028
NNG Demand						**$**	**3,908,779**	54,901,770	**$0.07120**
Viking (VGT)									
FT-A ZONE 1 - 1	AF0012	Annual	7,966	12	$3.4671	$	331,427	54,901,770	$0.00604
FT-A ZONE 1 - 1	AF0160	Winter	0	4	$3.7671	$	-	54,901,770	$0.00000
NNG-TF12 Base	112495	Annual	0	12	$7.5776	$	-	54,901,770	$0.00000
NNG-TF12 Variable	112495	Annual	0	12	$9.0926	$	-	54,901,770	$0.00000
NNG-TF5 Chisago	112495	Winter	0	5	$15.1530	$	-	54,901,770	$0.00000
NNG-TFX 12 Chisago	112486	Annual	0	12	$9.6288	$	-	54,901,770	$0.00000
NNG-TFX 5 Chisago	112486	Annual	0	12	$15.1530	$	-	54,901,770	$0.00000
Wadena Delivered Option		Winter	5,902	3	$0.9000	$	15,935	54,901,770	$0.00029
VGT Demand						**$**	**347,362**	54,901,770	**$0.00633**
Great Lakes (GLGT)									
FT-A	FT0016	Annual	10,130	12	$3.4580	$	420,354	54,901,770	$0.00766
FT Western Zone (12)	FT0155	Annual	1,178	12	$3.4580	$	48,882	54,901,770	$0.00089
FT Western Zone (5)	FT0155	Winter	5,738	5	$3.4580	$	99,210	54,901,770	$0.00181
FT Wester Zone	FT8466	Annual	3,000	12	$3.4580	$	124,488	54,901,770	$0.00227
GLGT Demand						**$**	**692,934**	54,901,770	**$0.01262**
Centra									
CENTRA TRANSMISSION	($Cdn/103M3)				$166.3160				
Conversion ((($Cdm103M3)*279.256)/9858)*.9		Annual	9,858	12	$4.5653	$	540,057	54,901,770	$0.00984
Union Balancing		Annual	4,500	12	$1.0000	$	54,000	54,901,770	$0.00098
CENTRA MINNESOTA PIPELINES		Annual	9,858	12	$1.2311	$	145,634	54,901,770	$0.00265
Centra Demand						**$**	**739,691**	54,901,770	**$0.01347**
AECO									
Niska Storage (AECO)		Annual	665,043	1	$1.4296	$	950,744	54,901,770	$0.01732
AECO/Emerson Swap		Annual	665,015	1	$0.4750	$	315,882	54,901,770	$0.00575
AECO Demand						**$**	**1,266,626**	**54,901,770**	**$0.02307**
NMU DEMAND - $/Ccf						**$**	**6,955,392**		**$0.12669**

For Joint Rate Demand **54,901,770** **Annual Firm Sales in therms**

	Units Dth's	**Months**	**Annual** Dth's
Northern Natural Gas (NNG)			
TF12B (Max Rate)	4,232	12	50,784
TF12V (Max Rate)	3,919	12	47,028
TF5 (Max Rate)	3,493	5	17,465
TF12B (Discount-Winter)	0	12	-
TF5 (Discount-Winter)	0	5	-
TFX5 (Discount)	649	5	3,245
TFX12 (Max Rate)	1,171	12	14,052
TFX Apr (Max Rate)	216	1	216
TFX Oct (Max Rate)	216	1	216
TFX5 (Max Rate)	6,208	5	31,040
TFX5 (Discount)	0	5	-
TFX5 (Discount)	195	5	975
TFX12 (Discount)	139	12	1,668
TFX12 (Discount)	895	12	10,740
TFX12 (Discount)	1,290	12	15,480
TFX5 (Discount)	41	5	205
TFX5 (Discount)	265	5	1,325
TFX5 (Discount)	2,401	5	12,005
Bison	5,411	11	56,816
NBPL	5,411	11	56,816
LS Power	3,149	3	9,447
WINDOM	0	12	-
SMS	2,454	12	29,448
Viking (VGT)			
FT-A ZONE 1 - 1	7,966	12	95,592
FT-A ZONE 1 - 1	0	4	-
NNG-TF12 Base	0	12	-
NNG-TF12 Variable	0	12	-
NNG-TF5 Chisago	0	5	-
NNG-TFX 12 Chisago	0	12	-
NNG-TFX 5 Chisago	0	12	-
Wadena Delivered Option	5,902	3	17,706
Great Lakes (GLGT)			
FT-A	10,130	12	121,560
FT Western Zone (12)	1,178	12	14,136
FT Western Zone (5)	5,738	5	28,690
FT Wester Zone	3,000	12	36,000
Centra			
CENTRA TRANSMISSION			
Conversion ((($Cdm103M3)*279.256)/9858)*.9537	9,858	12	118,296
Union Balancing	4,500	12	54,000
CENTRA MINNESOTA PIPELINES	9,858	12	118,296

Total Demand Cost	$	6,955,392	
Total Demand Weighted Vol in Mcf		7,909,500	
Total Joint Demand Rate $/Mcf			**$0.87937**

MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2010

PRESENT AVERAGE COST OF GAS **EFFECTIVE:** **01-Nov-10**

COMMODITY

WACOG		**Annual**	**Call Option**	**Total Annual**	**Cost/therm**
NNG	**Rate**	**Dth**	**Premium**	**Cost**	
GAS COST	$3.98990				
FUEL 0.52%	$0.02086				
COMMODITY TRANSPORTATION	$0.03620				
ACA	$0.00190				
GRI FEE	$0.00000				
NNG Commodity	$4.04886	2,512,662	$28,300	$10,201,718	$0.15220
VGT					
GAS COST	$3.63110				
FUEL 1.92%	$0.07108				
COMMODITY TRANSPORTATION	$0.01300				
GRI	$0.00000				
ACA	$0.00190				
VGT Commodity	$3.71708	1,827,195	$12,578	$6,804,408	$0.10151
GLGT					
GAS COST	$3.63110				
FUEL 1.076%	$0.03950				
COMMODITY TRANSPORTATION	$0.00326				
GRI	$0.00000				
ACA	$0.00190				
GLGT Commodity	$3.67576	966,200	$15,722	$3,567,240	$0.05322
CENTRA					
CENTRA TRANSM ($Cdn/103M3)	1.062				
Conversion x0.9306	$0.02936				
GAS COSTS	$3.63110				
CUSTOMS FEE	$0.00029				
CENTRA Commodity	$3.66075	1,396,834	$12,578	$5,126,031	$0.07647
NMU Weighted Average gas cost - $/Dth		**6,702,891**	**$69,177**	**$25,699,397**	**$0.38341**
	Total Annual Sales in therms	**67,028,910**			

MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

NOVEMBER 1, 2010

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR08-836* Oct. 08	Demand Change G011- M-08- Oct .08	Last Demand Change G011- M-09- Oct. 09	Most Recent PGA Oct. 2010	Current Proposal Effective Nov.1,2010	Result of Proposed Change: Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service: Avg. Annual Use:				**140**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	-68.28%	5.34%	$0.2047
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.0182	-10.84%	-11.05%	-0.35%	($0.0036)
Commodity Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2319	-39.65%	-47.47%	2.86%	$0.2011
Avg Annual Cost	$1,677.68	$1,401.47	$993.78	$984.31	$1,012.46	-39.65%	-47.47%	2.86%	$28.15
Effect of proposed commodity change on average annual bills:									$28.65
Effect of proposed demand change on average annual bills:									($0.50)
2) Large General Service: Avg. Annual Use:				**6,917**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	-38.62%	5.34%	$0.2047
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.0182	-10.84%	-9.10%	-0.35%	($0.0036)
Commodity Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2319	-39.65%	-27.76%	2.86%	$0.2011
Avg Annual Cost	$82,889.18	$69,242.63	$49,099.63	$48,632.04	$50,022.81	-39.65%	-27.76%	2.86%	$1,390.77
Effect of proposed commodity change on average annual bills:									$1,415.62
Effect of proposed demand change on average annual bills:									($24.85)
3) SV Interruptible Service: Avg. Annual Use:				**6,333**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	-38.62%	5.34%	$0.2047
Commodity Margin	$1.0127	$1.0127	$1.0127	$0.9560	$0.9560	-5.60%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.5905	$4.7055	$4.7891	$4.9938	-47.66%	-34.21%	4.27%	$0.2047
Avg Annual Cost	$60,426.32	$48,070.64	$29,799.93	$30,329.37	$31,625.47	-47.66%	-34.21%	4.27%	$1,296.10
Effect of proposed commodity change on average annual bills:									$1,296.10
4) LV Interruptible Service: Avg. Annual Use:				**37,114**	**Mcf**				
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	-38.62%	5.34%	$0.2047
Commodity Margin	$0.3395	$0.3395	$0.3395	$0.2846	$0.2846	-16.17%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$6.9173	$4.0323	$4.1177	$4.3224	-51.26%	-37.51%	4.97%	$0.2047
Avg Annual Cost	$329,138.09	$256,728.67	$149,654.78	$152,824.32	$160,419.99	-51.26%	-37.51%	4.97%	$7,595.67
Effect of proposed commodity change on average annual bills:									$7,595.67

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

*Implemented with Interim rates

**Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

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

DEMAND

Contract Type		Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Cost/Ccf
Northern Natural Gas (NNG)								
TF12B (Max Rate)	112495	Annual	4,232	12	$7.5776	$ 384,821	54,901,770	$0.00701
TF12V (Max Rate)	112495	Annual	3,919	12	$9.0926	$ 427,607	54,901,770	$0.00779
TF5 (Max Rate)	112495	Winter	3,493	5	$15.1530	$ 264,647	54,901,770	$0.00482
TF12B (Discount-Winter)	112495	Annual	0	12	$6.4818	$ -	54,901,770	$0.00000
TF5 (Discount-Winter)	112495	Winter	0	5	$7.6000	$ -	54,901,770	$0.00000
TFX5 (Discount)	112561	Winter	649	5	$4.5600	$ 14,797	54,901,770	$0.00027
TFX12 (Max Rate)	112486	Annual	1,171	12	$9.6288	$ 135,304	54,901,770	$0.00246
TFX Apr (Max Rate)	112486	Summer	216	1	$5.6830	$ 1,228	54,901,770	$0.00002
TFX Oct (Max Rate)	112486	Summer	216	1	$5.6830	$ 1,228	54,901,770	$0.00002
TFX5 (Max Rate)	112486	Winter	6,208	5	$15.1530	$ 470,349	54,901,770	$0.00857
TFX5 (Discount)	112486	Winter	0	5	$13.8736	$ -	54,901,770	$0.00000
TFX5 (Discount)	112486	Winter	195	5	$7.6050	$ 7,415	54,901,770	$0.00014
TFX12 (Discount)	111866	Annual	139	12	$4.8640	$ 8,113	54,901,770	$0.00015
TFX12 (Discount)	111866	Annual	895	12	$5.4720	$ 58,769	54,901,770	$0.00107
TFX12 (Discount)	111866	Annual	1,290	12	$2.2192	$ 34,353	54,901,770	$0.00063
TFX5 (Discount)	111866	Winter	41	5	$4.8640	$ 997	54,901,770	$0.00002
TFX5 (Discount)	111866	Winter	265	5	$5.4720	$ 7,250	54,901,770	$0.00013
TFX5 (Discount)	111866	Winter	2,401	5	$15.1392	$ 181,746	54,901,770	$0.00331
Bison	FT0003	Annual	5,411	10.5	$17.4800	$ 993,135	54,901,770	$0.01809
NBPL	T8673F	Annual	5,411	10.5	$6.9920	$ 397,254	54,901,770	$0.00724
LS Power		Winter	3,149	3	$4.3463	$ 41,059	54,901,770	$0.00075
WINDOM		Annual	0	12	$0.0000	$ -	54,901,770	$0.00000
SMS	112521	Annual	2,454	12	$2.1800	$ 64,197	54,901,770	$0.00117
FDD - Reservation	118657	Annual	0	12	$1.7140	$ -	54,901,770	$0.00000
FDD - Storage Cycle	118657	Annual	0	5	$0.3567	$ -	54,901,770	$0.00000
FDD - Reservation	118657	Annual	0	12	$3.3157	$ -	54,901,770	$0.00000
FDD - Storage Cycle	118657	Annual	0	5	$0.6901	$ -	54,901,770	$0.00000
FDD - Reservation	121292	Annual	0	12	$1.7140	$ -	54,901,770	$0.00000
FDD - Storage Cycle	121292	Annual	0	5	$0.3567	$ -	54,901,770	$0.00000
NNG Demand						**$ 3,494,269**	54,901,770	**$0.06365**
Viking (VGT)								
FT-A ZONE 1 - 1	AF0012	Annual	7,966	12	$3.4671	$ 331,427	54,901,770	$0.00604
FT-A ZONE 1 - 1	AF0160	Winter	0	4	$3.7671	$ -	54,901,770	$0.00000
NNG-TF12 Base	112495	Annual	0	12	$7.5776	$ -	54,901,770	$0.00000
NNG-TF12 Variable	112495	Annual	0	12	$9.0926	$ -	54,901,770	$0.00000
NNG-TF5 Chisago	112495	Winter	0	5	$15.1530	$ -	54,901,770	$0.00000
NNG-TFX 12 Chisago	112486	Annual	0	12	$9.6288	$ -	54,901,770	$0.00000
NNG-TFX 5 Chisago	112486	Annual	0	12	$15.1530	$ -	54,901,770	$0.00000
Wadena Delivered Option		Winter	5,902	3	$0.9000	$ 15,935	54,901,770	$0.00029
VGT Demand						**$ 347,362**	54,901,770	**$0.00633**
Great Lakes (GLGT)								
FT-A	FT0016	Annual	10,130	12	$3.4580	$ 420,354	54,901,770	$0.00766
FT Western Zone (12)	FT0155	Annual	1,178	12	$3.4580	$ 48,882	54,901,770	$0.00089
FT Western Zone (5)	FT0155	Winter	5,738	5	$3.4580	$ 99,210	54,901,770	$0.00181
FT Wester Zone	FT8466	Annual	3,000	12	$3.4580	$ 124,488	54,901,770	$0.00227
GLGT Demand						**$ 692,934**	54,901,770	**$0.01262**
Centra								
CENTRA TRANSMISSION	($Cdn/103M3)				$166.3160			
Conversion ((($Cdm103M3)*279.256)/9858)*.9		Annual	9,858	12	$4.5653	$ 540,057	54,901,770	$0.00984
Union Balancing		Annual	4,500	12	$1.0000	$ 54,000	54,901,770	$0.00098
CENTRA MINNESOTA PIPELINES		Annual	9,858	12	$1.2311	$ 145,634	54,901,770	$0.00265
Centra Demand						**$ 739,691**	54,901,770	**$0.01347**
AECO								
Niska Storage (AECO)		Annual	665,043	0	$0.0000	$ -	54,901,770	$0.00000
AECO/Emerson Swap		Annual	665,015	1	$0.4750	$ 315,882	54,901,770	$0.00575
AECO Demand						**$ 315,882**	**54,901,770**	**$0.00575**
NMU DEMAND - $/Ccf						**$ 5,590,138**		**$0.10182**

For Joint Rate Demand — **54,901,770** Annual Firm Sales in therms

	Units Dth's	Months	Annual Dth's
Northern Natural Gas (NNG)			
TF12B (Max Rate)	4,232	12	50,784
TF12V (Max Rate)	3,919	12	47,028
TF5 (Max Rate)	3,493	5	17,465
TF12B (Discount-Winter)	0	12	-
TF5 (Discount-Winter)	0	5	-
TFX5 (Discount)	649	5	3,245
TFX12 (Max Rate)	1,171	12	14,052
TFX Apr (Max Rate)	216	1	216
TFX Oct (Max Rate)	216	1	216
TFX5 (Max Rate)	6,208	5	31,040
TFX5 (Discount)	0	5	-
TFX5 (Discount)	195	5	975
TFX12 (Discount)	139	12	1,668
TFX12 (Discount)	895	12	10,740
TFX12 (Discount)	1,290	12	15,480
TFX5 (Discount)	41	5	205
TFX5 (Discount)	265	5	1,325
TFX5 (Discount)	2,401	5	12,005
Bison	5,411	11	56,816
NBPL	5,411	11	56,816
LS Power	3,149	3	9,447
WINDOM	0	12	-
SMS	2,454	12	29,448
Viking (VGT)			
FT-A ZONE 1 - 1	7,966	12	95,592
FT-A ZONE 1 - 1	0	4	-
NNG-TF12 Base	0	12	-
NNG-TF12 Variable	0	12	-
NNG-TF5 Chisago	0	5	-
NNG-TFX 12 Chisago	0	12	-
NNG-TFX 5 Chisago	0	12	-
Wadena Delivered Option	5,902	3	17,706
Great Lakes (GLGT)			
FT-A	10,130	12	121,560
FT Western Zone (12)	1,178	12	14,136
FT Western Zone (5)	5,738	5	28,690
FT Wester Zone	3,000	12	36,000
Centra			
CENTRA TRANSMISSION			
Conversion ((($Cdm103M3)*279.256)/9858)*.9537	9,858	12	118,296
Union Balancing	4,500	12	54,000
CENTRA MINNESOTA PIPELINES	9,858	12	118,296

Total Demand Cost	$ 5,590,138	
Total Demand Weighted Vol in Mcf	7,909,500	
Total Joint Demand Rate $/Mcf		**$0.70676**

MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2010

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

PRESENT AVERAGE COST OF GAS **EFFECTIVE: 01-Nov-10**

COMMODITY

		Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate ($/therm)
NNG								
	FDD - Reservation	Annual	8,164	12	$1.71400	$167,917.15	67,028,910	$0.00251
	FDD - Storage Cycle	Annual	94,137	5	$0.35670	$167,893.34	67,028,910	$0.00250
	FDD - Reservation	Annual	601	12	$3.31570	$23,912.83	67,028,910	$0.00036
	FDD - Storage Cycle	Annual	6,926	5	$0.69010	$23,898.16	67,028,910	$0.00036
	FDD - Reservation	Annual	751	12	$1.71400	$15,446.57	67,028,910	$0.00023
	FDD - Storage Cycle	Annual	8,658	5	$0.35670	$15,441.54	67,028,910	$0.00023
						$414,509.59	67,028,910	$0.00618

		Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate ($/therm)
AECO								
	Niska Storage (AECO)	Annual	665,043	1	$ 1.42960	$950,744.00	67,028,910	$0.01418
						$1,365,253.59	67,028,910	$0.02037

WACOG		Annual	Call Option	Total Annual	Cost/therm			
NNG	**Rate**	**Dth**	**Premium**	**Cost**				
GAS COST	$3.98990							
FUEL 0.52%	$0.02086							
COMMODITY TRANSPORTATION	$0.03620							
ACA	$0.00190							
GRI FEE	$0.00000							
NNG Commodity	$4.04886	2,512,662	$28,300	$10,201,718	$0.15220			
VGT								
GAS COST	$3.63110							
FUEL 1.92%	$0.07108							
COMMODITY TRANSPORTATION	$0.01300							
GRI	$0.00000							
ACA	$0.00190							
VGT Commodity	$3.71708	1,827,195	$12,578	$6,804,408	$0.10151			
GLGT								
GAS COST	$3.63110							
FUEL 1.076%	$0.03950							
COMMODITY TRANSPORTATION	$0.00326							
GRI	$0.00000							
ACA	$0.00190							
GLGT Commodity	$3.67576	966,200	$15,722	$3,567,240	$0.05322			
CENTRA								
CENTRA TRANSM ($Cdn/103M3)	1.062							
Conversion x0.9306	$0.02936							
GAS COSTS	$3.63110							
CUSTOMS FEE	$0.00029							
CENTRA Commodity	$3.66075	1,396,834	$12,578	$5,126,031	$0.07647			
NMU Weighted Average gas cost - $/Dth		**6,702,891**	**$69,177**	**$25,699,397**	**$0.38341**	$25,699,397	67,028,910	$0.38341
Total Annual Sales in therms		**67,028,910**						
				Total Commodity Cost		$27,064,650.87	67,028,910	$0.40378

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 5

MINNESOTA ENERGY RESOURCES - NMU

Financial Options

Heating Season 2010-2011

[TRADE SECRET DATA BEGINS

Units - Gas Daily Packages

No Gas Daily Peakers were purchased

Units - Futures (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1												-
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
Total		6,333		4,194		6,452		3,929		7,419	27,859	860,000
		190,000		130,000		200,000		110,000		230,000		860,000

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		7,333		10,968		11,613		11,071		8,387	49,373	1,490,000
		220,000		340,000		360,000		310,000		260,000		1,490,000

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
1												
2												
3												
4												
5												
6												
Total	**$ 0.3146**	**$ 69,205**	**$ 0.3341**	**$ 113,608**	**$ 0.4097**	**$ 147,502**	**$ 0.4618**	**$ 143,154**	**$ 0.4563**	**$ 118,649**	**$ 0.3974**	**$ 592,119**

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED**

Attachment 6

MINNESOTA ENERGY RESOURCES - NMU

	M-06-NMU GS	M-07-1402 NMU GS	G007/ M-08-1329 NMU GS	M-09-NMU GS	**M-10-NMU GS**	Proposed Change
NNG Design Day	23,197	21,635	21,491	**24,680**	**23,615**	-1,065
Customer Requirements moving to Transportation	125					
Adjusted Design Day	23,072					
Adjusted Design Day Percentages	3.89%	100.00%	100.00%	**100.00%**	**100.00%**	0.00%
Factors for All Winter Capacity	5.67%	100.00%	100.00%	**100.00%**	**100.00%**	0.00%
NNG Allocated Entitlements in PGA						
TF12B	8,613	7,340	2,954	**7,513**	**4,232**	-3,281
TF12V	0	5,930	9,802	**5,243**	**3,919**	-1,324
TF(5)	10,611	2,102	1,991	**1,991**	**3,493**	1,502
TFX(5)	2,831	5,514	6,139	**6,139**	**0**	-6,139
LS Power		0	0	**2,725**	**0**	-2,725
TFX(5)	766	0	0	**0**	**0**	0
Peak Capacity 3 mo.	1,418	0	0	**0**	**0**	0
Total NNG Allocated Entitlements in PGA	24,238	20,886	20,886	**23,611**	**11,644**	-11,967
Other Pipelines Entitlements in PGA						
Viking FT-A	8,366	7,966	331,427	**7,966**	**331,427**	323,461
Viking FT-A Backhaul	1,900	4,625	0	**5,902**	**0**	-5,902
Viking/NNG Chisago TF12 Base	1,303	1,821	782	**1,368**	**0**	-1,368
Viking/NNG Chisago TF12 Variable	0	0	0	**955**	**0**	-955
Viking/NNG Chisago TF5	2,839	441	1,765	**563**	**0**	-563
Viking/NNG Chisago TFX 12	0	725	1,963	**2,089**	**0**	-2,089
Viking/NNG Chisago TFX 5	0	1,637	476	**926**	**0**	-926
Great Lakes FT-A (12)	13,130	11,308	593,724	**14,308**	**593,724**	579,416
Great Lakes FT-A (5)	0	2,138	99,210	**2,138**	**99,210**	97,072
Centra FT-1	8,358	9,858	540,057	**9,858**	**540,057**	530,199
Centra -Boise	1,500	0	0	**0**	**0**	0
Nexen Exchange	4,600	6,000	0	**0**	**0**	0
Tenaska PSO GL	86,549	0	0	**0**	**0**	0
Tenaska PSO Centra	62,000	0	0	**0**	**0**	0
ANR Storage	0	0	0	**0**	**0**	0
Total Capacity	212,883	62,780	1,590,290	**63,783**	**1,576,062**	1,512,279
Total NNG Transportation	24,238	20,886	20,886	**23,611**	**11,644**	-11,967
Total Transportation	59,734	56,780	1,590,290	**63,783**	**1,576,062**	1,512,279
Total Seasonal Transportation	15,625	7,616	8,130	**10,855**	**3,493**	-7,362
Percent Seasonal on NNG	64.5%	36.5%	38.9%	**46.0%**	**30.0%**	-16.0%
Other Entitlements not included in Peak Day Deliverability						
TFX Offpeak Old (Apr/Oct) one mo.	3,694	0	0	**0**	**0**	0
TFX (Apr/Oct) one mo.	2,108	0	0	**0**	**0**	0
TFX Apr.-Oct. 7 mos.	329	0	0	**0**	**0**	0
TFX May-Sept 5 mos.	568	0	0	**0**	**0**	0
FDD Storage reservation per mo.	5,402	6,343	7,619	**7,830**	**9,516**	1,686
FDD Storage capacity per mo.	311,440	365,682	428,702	**451,428**	**548,602**	97,174
ANR Capacity per mo.	0	0	0	**0**	**0**	0
Nexen PSO	9,916	600,000	684,604	**684,604**	**#REF!**	#REF!
Tenaska PSO	19,443	15,807	17,763	**0**	**0**	0
AECO Storage	0	0	0	**0**	**665,043**	665,043
NGPL per mo.	138,365	0	0	**0**	**0**	0
SMS per mo.	2,100	1,907	2,172	**2,143**	**2,454**	311
SBA	0	0	0	**0**	**0**	0
Upstream Demand per mo.	32	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - NMU

Rate Impacts
NMU

General Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-08-XXXX	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	3.83%	0.03%	$0.0010
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.2669	10.94%	15.91%	23.99%	$0.2451
Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2769	-39.28%	2.51%	3.50%	$0.2461
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas	$1,677.68	$1,401.47	$993.78	$984.31	$1,018.76	-39.28%	2.51%	3.50%	$34.45

Large General Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	3.83%	0.03%	$0.0010
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.2669	10.94%	15.91%	23.99%	$0.2451
Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.3126	0.00%	0.00%	6.28%	$0.1367
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.4136	-38.13%	4.44%	5.44%	$0.3828
Average Annual Use	6,917	6,917	6,917	6,917	6,917				
Average Annual Cost of Gas	$82,889.18	$69,242.63	$49,099.63	$48,632.04	$51,279.73	-38.13%	4.44%	5.44%	$2,647.69

SV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	3.83%	0.03%	$0.0010
Commodity Margin	$1.0127	$1.0127	$1.0127	$0.9560	$0.9560	-5.60%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.5905	$4.7055	$4.7891	$4.7901	-49.80%	1.80%	0.02%	$0.0010
Average Annual Use	6,333	6,333	6,333	6,333	6,333				
Average Annual Cost of Gas	$60,426.32	$48,070.64	$29,799.93	$30,329.37	$30,335.70	-49.80%	1.80%	0.02%	$6.33

LV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-07-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$3.8341	-55.05%	3.83%	0.03%	$0.0010
Commodity Margin	$0.3395	$0.3395	$0.3395	$0.2846	$0.2846	-16.17%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$6.9173	$4.0323	$4.1177	$4.1187	-53.56%	2.14%	0.02%	$0.0010
Average Annual Use	37,114	37,114	37,114	37,114	37,114				
Average Annual Cost of Gas	$329,138.09	$256,728.67	$149,654.78	$152,824.32	$152,861.43	-53.56%	2.14%	0.02%	$37.11

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.0010	0.10%	$0.2399	$0.2451	23.99%	$0.2461	3.50%	$34.45
Large General Service	$0.0010	0.10%	$0.2399	$0.2451	23.99%	$0.3828	5.44%	$2,647.69
SV Interruptible Service	$0.0010	$0.0010	$0.0000	$0.0000	0.00%	$0.0010	0.02%	$6.33
LV Interruptible Service	$0.0010	$0.0010	$0.0000	$0.0000	0.00%	$0.0010	0.02%	$37.11

MINNESOTA ENERGY RESOURCES - NMU

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

NMU

General Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-08-XXXX	Last Demand Change M-09-XXXX	Most Recent PGA Oct 1/10	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	9.34%	5.34%	$0.2047
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.0182	-10.84%	-6.84%	-0.35%	($0.0036)
Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2319	-39.65%	1.88%	2.86%	$0.2011
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas*	$1,677.68	$1,401.47	$993.78	$984.31	$1,012.46	-39.65%	1.88%	2.86%	$28.15

Large General Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-08-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	9.34%	5.34%	$0.2047
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0218	$1.0182	-10.84%	-6.84%	-0.35%	($0.0036)
Margin	$2.3126	$2.3126	$2.3126	$2.1759	$2.1759	-5.91%	-5.91%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.0308	$7.2319	-39.65%	1.88%	2.86%	$0.2011
Average Annual Use	6,917	6,917	6,917	6,917	6,917				
Average Annual Cost of Gas*	$82,889.18	$69,242.63	$49,099.63	$48,632.04	$50,022.81	-39.65%	1.88%	2.86%	$1,390.77

SV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-08-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	9.34%	5.34%	$0.2047
Commodity Margin	$1.0127	$1.0127	$1.0127	$0.9560	$0.9560	-5.60%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.5905	$4.7055	$4.7891	$4.9938	-47.66%	6.13%	4.27%	$0.2047
Average Annual Use	6,333	6,333	6,333	6,333	6,333				
Average Annual Cost of Gas*	$60,426.32	$48,070.64	$29,799.93	$30,329.37	$31,625.47	-47.66%	6.13%	4.27%	$1,296.10

LV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-08-XXXX	Last Demand Change M-08-XXXX	Most Recent PGA Oct 1/09	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.8331	$4.0378	-52.66%	9.34%	5.34%	$0.2047
Commodity Margin	$0.3395	$0.3395	$0.3395	$0.2846	$0.2846	-16.17%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$6.9173	$4.0323	$4.1177	$4.3224	-51.26%	7.19%	4.97%	$0.2047
Average Annual Use	37,114	37,114	37,114	37,114	37,114				
Average Annual Cost of Gas*	$329,138.09	$256,728.67	$149,654.78	$152,824.32	$160,419.99	-51.26%	7.19%	4.97%	$7,595.67

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.2047	20.47%	($0.0035)	($0.0036)	-0.35%	$0.2011	2.86%	$28.15
Large General Service	$0.2047	20.47%	($0.0035)	($0.0036)	-0.35%	$0.2011	2.86%	$1,390.77
SV Interruptible Service	$0.2047	$0.2047	$0.0000	$0.0000	0.00%	$0.2047	4.27%	$1,296.10
LV Interruptible Service	$0.2047	$0.2047	$0.0000	$0.0000	0.00%	$0.2047	4.97%	$7,595.67

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

Attachment 8

MINNESOTA ENERGY RESOURCES - NMU

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

NMU

	Oct. 2010 Entitlements	Nov. 2010 Entitlements	Entitlement Change	Oct. 2010 Rate	Months	Oct. 2010 Total Annual Cost	Nov. 2010 Total Annual Cost	Total Annual Cost Change
NNG Pipeline								
TF12B (Max Rate)	7,513	4,232	-3,281	$ 7.5776	12	$683,165	$384,821	-$298,344
TF12V (Max Rate)	5,243	3,919	-1,324	$ 9.0926	12	$572,069	$427,607	-$144,462
TF5 (Max Rate)	1,991	3,493	1,502	$ 15.1530	5	$150,848	$264,647	$113,799
TF12B (Discount-Winter)	0	0	0	$ 6.4818	12	$0	$0	$0
TF5 (Discount-Winter)	0	0	0	$ 7.6000	5	$0	$0	$0
TFX5 (Discount)	0	649	649	$ 4.5600	5	$0	$14,797	$14,797
TFX12 (Max Rate)	0	1,171	1,171	$ 9.6288	12	$0	$135,304	$135,304
TFX Apr (Max Rate)	0	216	216	$ 5.6830	1	$0	$1,228	$1,228
TFX Oct (Max Rate)	0	216	216	$ 5.6830	1	$0	$1,228	$1,228
TFX5 (Max Rate)	6,139	6,208	69	$ 15.1530	5	$465,121	$470,349	$5,228
TFX5 (Discount)	0	0	0	$ 13.8736	5	$0	$0	$0
TFX5 (Discount)	0	195	195	$ 7.6050	5	$0	$7,415	$7,415
TFX12 (Discount)	0	139	139	$ 4.8640	12	$0	$8,113	$8,113
TFX12 (Discount)	0	895	895	$ 5.4720	12	$0	$58,769	$58,769
TFX12 (Discount)	0	1,290	1,290	$ 2.2192	12	$0	$34,353	$34,353
TFX5 (Discount)	0	41	41	$ 4.8640	5	$0	$997	$997
TFX5 (Discount)	0	265	265	$ 5.4720	5	$0	$7,250	$7,250
TFX5 (Discount)	0	2,401	2,401	$ 15.1392	5	$0	$181,746	$181,746
Bison	0	5,411	5,411	$ 17.4800	11	$0	$993,135	$993,135
NBPL	0	5,411	5,411	$ 6.9920	11	$0	$397,254	$397,254
LS Power	2,725	3,149	424	$ 4.3463	3	$35,525	$41,059	$5,534
WINDOM	0	0	0	$ -	12	$0	$0	$0
NNG 3-Party demand								
Producer Demand	$0	$0	$0			$0	$0	$0
Call Options Premium	$1,041,321	$592,119	-$449,202			$1,041,321	$592,119	-$449,202
Upstream Demand Costs								
SMS	2,103	2,454	351	$ 2.1800	12	$55,005	$64,197	$9,192
FDD - Reservation	7,315	8,164	849	$ 1.7140	12	$150,464	$167,917	$17,453
FDD - Storage Cycle	84,352	94,137	9,785	$ 0.3567	5	$150,442	$167,893	$17,451
FDD - Reservation	515	601	86	$ 3.3157	12	$20,472	$23,913	$3,441
FDD - Storage Cycle	5,933	6,926	993	$ 0.6901	5	$20,473	$23,898	$3,425
FDD - Reservation	0	751	751	$ 1.7140	12	$0	$15,447	$15,447
FDD - Storage Cycle	0	8,658	8,658	$ 0.3567	5	$0	$15,442	$15,442
Viking Pipeline								
FTA (AF0012)	7,966	7,966	0	$ 3.4671	12	$331,427	$331,427	$0
FT-A Zone 1-1 Backhaul	5,902	0	-5,902	$ 3.7671	5	$111,167	$0	-$111,167
NNG TF12 Chisago (112495) - Base	1,368	0	-1,368	$ 7.5776	12	$124,432	$0	-$124,432
NNG TFX12 Chisago (112486)	2,089	0	-2,089	$ 9.6288	12	$241,411	$0	-$241,411
NNG TF12 Chisago (112495) - Variable	955	0	-955	$ 9.0926	12	$104,232	$0	-$104,232
NNG TF5 Chisago (112495)	563	0	-563	$ 15.1530	5	$42,672	$0	-$42,672
NNG TF5 Chisago (112486)	926	0	-926	$ 15.1530	5	$70,141	$0	-$70,141
Wadena Delivered Option	0	5,902	5,902	$ 0.9000	3	$0	$15,935	$15,935
GLGTPipeline								
FT-A	10,130	10,130	0	$ 3.4580	12	$420,354	$420,354	$0
FT Western Zone (12)	1,178	1,178	0	$ 3.4580	12	$48,882	$48,882	$0

MINNESOTA ENERGY RESOURCES - NMU

NNG-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	103	2,495	238	-4.00%	24,593	23,615
Off Peak	55	2,495	238	-4.00%	14,737	14,151

GLGT-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	106	894	151	-4.00%	15,584	14,964
Off Peak	57	894	151	-4.00%	9,451	9,075

VGT-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	109	1,702	105	-4.00%	11,283	10,835
Off Peak	57	1,702	105	-4.00%	6,943	6,667

Centra-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	107	1,324	85	-4.00%	8,590	8,248
Off Peak	57	1,324	85	-4.00%	5,410	5,196

Total-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	0	6,415	579	-4.00%	60,050	57,662
Off Peak	0	6,415	579	-4.00%	36,541	35,089

MINNESOTA ENERGY RESOURCES - NMU

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

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES - NMU

10/11 Winter Portfolio Plan - MERC GLGT-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES - NMU

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

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES - NMU

10/11 Winter Portfolio Plan - MERC Centra-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (NMU)

NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total
Total			**548,602**							

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ENERGY RESOURCES

GLGT/VGT/Centra WINTER PLAN (NMU)

NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

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

TRADE DATA SECRET ENDS]

STORAGE
No Storage

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

Attachment 11

MINNESOTA ENERGY RESOURCES - NMU

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

Base	8,120
Variable	589

Date	100.00% Cloquet Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/09	0	0	17,163	8,120
7/2/09	1	1	11,186	8,780
7/3/09	8	8	10,712	13,020
7/4/09	7	7	7,855	12,408
7/5/09	0	0	10,618	8,120
7/6/09	0	0	16,349	8,120
7/7/09	8	8	26,016	12,573
7/8/09	7	7	21,123	12,007
7/9/09	2	2	17,077	9,392
7/10/09	5	5	18,151	11,183
7/11/09	11	11	14,712	14,599
7/12/09	2	2	11,203	9,475
7/13/09	2	2	16,489	9,486
7/14/09	2	2	17,618	9,357
7/15/09	0	0	19,144	8,120
7/16/09	1	1	19,561	8,733
7/17/09	6	6	22,153	11,760
7/18/09	0	0	15,382	8,120
7/19/09	9	9	11,358	13,162
7/20/09	2	2	15,383	9,322
7/21/09	4	4	14,958	10,594
7/22/09	3	3	16,053	9,993
7/23/09	7	7	16,204	12,408
7/24/09	0	0	16,256	8,120
7/25/09	0	0	10,786	8,120
7/26/09	0	0	11,303	8,120
7/27/09	0	0	16,849	8,120
7/28/09	0	0	16,704	8,120
7/29/09	0	0	16,421	8,120
7/30/09	0	0	16,264	8,120
7/31/09	1	1	16,482	8,721
8/1/09	0	0	14,794	8,120
8/2/09	2	2	11,403	9,345
8/3/09	2	2	15,737	9,345
8/4/09	0	0	17,302	8,120
8/5/09	0	0	17,685	8,120
8/6/09	1	1	18,012	8,750
8/7/09	2	2	14,515	9,369
8/8/09	3	3	8,284	9,958
8/9/09	4	4	9,316	10,664
8/10/09	10	10	14,697	14,187
8/11/09	3	3	26,017	9,958
8/12/09	4	4	18,559	10,570
8/13/09	0	0	15,228	8,120
8/14/09	1	1	15,739	8,762
8/15/09	6	6	11,681	11,725
8/16/09	0	0	11,714	8,120
8/17/09	0	0	18,926	8,120
8/18/09	0	0	18,889	8,120

9/26/09	0	0	10,415	8,120
9/27/09	13	13	14,314	15,541
9/28/09	17	17	24,053	18,015
9/29/09	16	16	24,930	17,573
9/30/09	21	21	27,187	20,206
10/1/09	19	19	26,090	19,464
10/2/09	17	17	25,313	18,204
10/3/09	25	25	23,763	22,680
10/4/09	23	23	25,885	21,938
10/5/09	21	21	33,676	20,206
10/6/09	16	16	38,749	17,750
10/7/09	16	16	36,952	17,485
10/8/09	15	15	37,200	16,943
10/9/09	19	19	33,706	19,335
10/10/09	24	24	32,351	22,344
10/11/09	15	15	28,291	17,108
10/12/09	13	13	35,087	15,541
10/13/09	14	14	33,698	16,390
10/14/09	22	22	31,597	21,355
10/15/09	24	24	32,154	22,374
10/16/09	26	26	28,271	23,434
10/17/09	25	25	23,602	22,992
10/18/09	25	25	18,663	22,751
10/19/09	17	17	33,513	18,204
10/20/09	31	31	29,455	26,567
10/21/09	29	29	33,199	25,437
10/22/09	29	29	34,529	24,977
10/23/09	24	24	31,678	21,985
10/24/09	24	24	25,150	22,397
10/25/09	21	21	27,172	20,318
10/26/09	28	28	34,187	24,518
10/27/09	37	37	33,652	29,889
10/28/09	32	32	34,821	26,850
10/29/09	29	29	31,732	25,272
10/30/09	14	14	30,551	16,466
10/31/09	25	25	29,901	22,615
11/1/09	25	25	28,965	22,963
11/2/09	20	20	39,005	19,871
11/3/09	16	16	36,025	17,573
11/4/09	7	7	37,365	12,490
11/5/09	12	12	32,169	14,988
11/6/09	20	20	21,272	19,982
11/7/09	32	32	20,954	26,738
11/8/09	46	46	23,323	35,450
11/9/09	46	46	26,465	34,925
11/10/09	45	45	25,896	34,554
11/11/09	37	37	25,120	29,766
11/12/09	35	35	25,851	28,918
11/13/09	31	31	25,904	26,096
11/14/09	37	37	36,584	29,889
11/15/09	44	44	37,523	33,959
11/16/09	45	45	38,053	34,837
11/17/09	50	50	37,536	37,741
11/18/09	46	46	33,893	35,473
11/19/09	50	50	31,272	37,664
11/20/09	61	61	31,938	43,755
11/21/09	54	54	27,316	39,667
11/22/09	46	46	25,325	35,332
11/23/09	43	43	29,661	33,718
11/24/09	51	51	34,697	38,018
11/25/09	50	50	35,283	37,847
11/26/09	44	44	32,702	34,207

1/3/10	59	59	65,710	42,771
1/4/10	80	80	68,182	55,193
1/5/10	70	70	65,580	49,574
1/6/10	54	54	64,043	39,973
1/7/10	69	69	69,445	48,720
1/8/10	71	71	66,053	49,980
1/9/10	67	67	58,218	47,324
1/10/10	61	61	54,710	43,914
1/11/10	64	64	57,029	46,099
1/12/10	81	81	55,461	55,617
1/13/10	83	83	49,170	57,125
1/14/10	90	90	49,283	61,077
1/15/10	85	85	45,329	58,373
1/16/10	80	80	39,029	55,387
1/17/10	66	66	41,859	47,283
1/18/10	56	56	47,368	41,210
1/19/10	58	58	51,039	42,459
1/20/10	57	57	48,967	41,834
1/21/10	53	53	44,910	39,361
1/22/10	54	54	39,906	39,961
1/23/10	79	79	31,442	54,710
1/24/10	80	80	35,205	55,417
1/25/10	80	80	56,097	55,193
1/26/10	78	78	70,656	54,321
1/27/10	69	69	76,724	48,938
1/28/10	66	66	76,216	47,194
1/29/10	74	74	65,782	51,777
1/30/10	64	64	57,828	45,580
1/31/10	38	38	57,399	30,667
2/1/10	60	60	62,225	43,395
2/2/10	74	74	61,943	51,659
2/3/10	76	76	58,983	53,072
2/4/10	69	69	50,251	48,938
2/5/10	47	47	47,880	35,756
2/6/10	40	40	40,698	31,845
2/7/10	47	47	40,820	35,726
2/8/10	42	42	45,504	32,699
2/9/10	35	35	52,619	28,570
2/10/10	36	36	55,528	29,041
2/11/10	37	37	50,948	29,948
2/12/10	48	48	50,673	36,109
2/13/10	55	55	43,726	40,262
2/14/10	64	64	46,133	45,845
2/15/10	57	57	47,905	41,811
2/16/10	45	45	45,660	34,342
2/17/10	53	53	47,627	39,219
2/18/10	72	72	49,067	50,716
2/19/10	67	67	47,761	47,453
2/20/10	57	57	41,320	41,487
2/21/10	61	61	41,955	43,755
2/22/10	66	66	47,853	46,829
2/23/10	57	57	59,229	41,516
2/24/10	42	42	60,756	32,858
2/25/10	50	50	51,636	37,652
2/26/10	69	69	43,582	48,655
2/27/10	75	75	40,052	52,407
2/28/10	66	66	36,671	46,994
3/1/10	70	70	39,633	49,167
3/2/10	58	58	40,139	42,094
3/3/10	49	49	42,265	36,840
3/4/10	38	38	43,091	30,384
3/5/10	31	31	41.113	26.226

4/12/10	24	24	27,011	22,480
4/13/10	28	28	28,487	24,506
4/14/10	26	26	25,486	23,581
4/15/10	22	22	26,994	21,231
4/16/10	14	14	25,030	16,083
4/17/10	9	9	24,813	13,303
4/18/10	25	25	21,244	22,886
4/19/10	35	35	23,726	28,529
4/20/10	33	33	24,573	27,581
4/21/10	26	26	32,476	23,699
4/22/10	21	21	27,456	20,725
4/23/10	8	8	20,800	12,697
4/24/10	22	22	20,951	21,314
4/25/10	25	25	18,030	22,751
4/26/10	32	32	21,794	27,251
4/27/10	30	30	26,215	25,931
4/28/10	25	25	23,945	22,886
4/29/10	27	27	26,287	24,170
4/30/10	18	18	23,737	18,581
5/1/10	24	24	20,131	22,244
5/2/10	22	22	21,480	20,842
5/3/10	22	22	28,474	20,842
5/4/10	16	16	27,508	17,573
5/5/10	14	14	29,901	16,160
5/6/10	5	5	27,571	11,271
5/7/10	12	12	31,064	15,376
5/8/10	20	20	26,055	20,094
5/9/10	25	25	26,363	23,104
5/10/10	23	23	32,066	21,596
5/11/10	15	15	35,261	16,778
5/12/10	7	7	31,573	12,149
5/13/10	15	15	33,685	17,002
5/14/10	24	24	24,157	22,244
5/15/10	25	25	12,670	22,763
5/16/10	28	28	13,189	24,759
5/17/10	13	13	17,802	15,683
5/18/10	11	11	17,954	14,776
5/19/10	28	28	19,988	24,759
5/20/10	0	0	18,663	8,120
5/21/10	18	18	18,811	18,934
5/22/10	8	8	16,050	12,573
5/23/10	17	17	13,323	18,015
5/24/10	9	9	19,563	13,686
5/25/10	16	16	17,135	17,662
5/26/10	15	15	17,778	16,861
5/27/10	24	24	18,247	22,115
5/28/10	9	9	15,270	13,256
5/29/10	11	11	9,871	14,540
5/30/10	22	22	10,643	20,960
5/31/10	21	21	10,054	20,725
6/1/10	14	14	17,342	16,083
6/2/10	21	21	23,467	20,318
6/3/10	11	11	26,043	14,363
6/4/10	3	3	19,706	10,081
6/5/10	21	21	18,247	20,318
6/6/10	21	21	15,230	20,206
6/7/10	24	24	19,087	22,221
6/8/10	22	22	20,657	21,231
6/9/10	12	12	21,495	15,471
6/10/10	13	13	20,241	15,612
6/11/10	15	15	17,751	17,132
6/12/10	6	6	13.263	11.831

Attachment 12

MINNESOTA ENERGY RESOURCES - NMU

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

Rate Class	Tariff Rate Designation	Jul-09 Average Customers	Aug-09 Average Customers	Sep-09 Average Customers	Oct-09 Average Customers	Nov-09 Average Customers	Dec-09 Average Customers	Jan-10 Average Customers	Feb-10 Average Customers	Mar-10 Average Customers	Apr-10 Average Customers	May-10 Average Customers	Jun-10 Average Customers
Residential w/ Heat	NM001	34,739	33,949	33,936	34,319	34,867	35,143	35,160	35,272	35,192	35,208	35,208	34,962
Residential w/o Heat	NM002	19	18	16	18	19	21	21	21	21	21	20	20
Commercial-SV	NM050/070	2,270	2,222	2,204	2,214	2,218	2,234	2,248	2,244	2,242	2,245	2,352	2,343
Commercial-LV	NM052/071	3,149	3,100	3,086	3,107	3,105	3,136	3,149	3,145	3,143	3,146	3,029	3,016
Industrial-LV	NM150	10	10	10	10	10	10	10	9	10	10	10	11
SV-Joint	NM100/101	0	0	0	0	0	0	0	0	0	0	0	0
SV-Interruptible	NM125	127	128	124	129	118	126	124	122	124	123	121	124
LV-Interruptible	NM200/201/210/211	12	12	12	12	12	12	12	13	12	12	11	11
Transport	NM500/512/501/502/522/70A/71A	9	9	10	7	7	8	8	9	8	8	8	12
Transport	NM503/511/504/506/508/74L/80A	7	7	9	9	9	9	9	10	9	9	9	9
Transport	NM516	0	0	0	0	0	0	0	0	0	0	0	0
Transport	NM507/513/514	8	8	8	9	8	10	8	30	16	18	8	8
Transport	NM72A/73A	0	0	0	0	0	0	0	0	0	0	0	0
Transport	NM510	0	0	0	0	0	0	0	0	0	0	0	0
Transport	NM515	0	0	0	0	0	0	0	0	0	0	0	0
Total		40,350	39,463	39,415	39,834	40,373	40,709	40,749	40,875	40,777	40,800	40,776	40,516

MINNESOTA ENERGY RESOURCES - NMU

Projected Fixed Cost - November 2009 through March 2010

Futures Contracts WACOG
NMU

Nov-10 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/18/10	36,538	$ 4.9860	$ 182,181	$ 3.4412	$ 125,736	$ 56,445
06/18/10	4,872	$ 5.4020	$ 26,317	$ 3.4412	$ 16,765	$ 9,553
06/18/10	34,103	$ 5.4040	$ 184,290	$ 3.4412	$ 117,353	$ 66,937
07/08/10	34,103	$ 4.8260	$ 164,579	$ 3.4412	$ 117,353	$ 47,226
08/05/10	29,231	$ 4.8000	$ 140,308	$ 3.4412	$ 100,589	$ 39,719
09/27/10	26,795	$ 3.8710	$ 103,723	$ 3.4412	$ 92,206	$ 11,517
10/05/10	7,308	$ 3.7240	$ 27,214	$ 3.4412	$ 25,147	$ 2,067
10/05/10	17,051	$ 3.7250	$ 63,516	$ 3.4412	$ 58,677	$ 4,839
Total	190,000		$ 892,128		$ 653,825	$ 238,303
WACOG			$ 4.6954		$ 3.4412	$ 1.2542

Dec-10 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/20/10	3,250	$ 5.1600	$ 16,770	$ 3.9089	$ 12,704	$ 4,066
05/20/10	3,250	$ 5.1610	$ 16,773	$ 3.9089	$ 12,704	$ 4,069
05/20/10	6,500	$ 5.1620	$ 33,553	$ 3.9089	$ 25,408	$ 8,145
05/20/10	3,250	$ 5.1630	$ 16,780	$ 3.9089	$ 12,704	$ 4,076
05/20/10	13,000	$ 5.1640	$ 67,132	$ 3.9089	$ 50,816	$ 16,316
06/29/10	35,750	$ 5.2840	$ 188,903	$ 3.9089	$ 139,743	$ 49,160
07/29/10	22,750	$ 5.1650	$ 117,504	$ 3.9089	$ 88,927	$ 28,576
08/06/10	16,250	$ 4.9940	$ 81,152	$ 3.9089	$ 63,520	$ 17,633
09/14/10	13,000	$ 4.3490	$ 56,537	$ 3.9089	$ 50,816	$ 5,721
10/07/10	13,000	$ 4.0600	$ 52,780	$ 3.9089	$ 50,816	$ 1,964
	130,000		$ 647,884		$ 508,156	$ 139,728
			$ 4.9837		$ 3.9089	$ 1.0748

Jan-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/21/10	28,986	$ 5.3350	$ 154,638	$ 4.0860	$ 118,434	$ 36,204
05/21/10	2,899	$ 5.3370	$ 15,470	$ 4.0860	$ 11,843	$ 3,626
06/28/10	2,899	$ 5.6450	$ 16,362	$ 4.0860	$ 11,843	$ 4,519
06/28/10	11,594	$ 5.6460	$ 65,461	$ 4.0860	$ 47,373	$ 18,087
06/28/10	28,986	$ 5.6490	$ 163,739	$ 4.0860	$ 118,434	$ 45,306
07/29/10	17,391	$ 5.2910	$ 92,017	$ 4.0860	$ 71,060	$ 20,957
07/29/10	2,899	$ 5.2920	$ 15,339	$ 4.0860	$ 11,843	$ 3,496
07/29/10	2,899	$ 5.2930	$ 15,342	$ 4.0860	$ 11,843	$ 3,499
07/29/10	14,493	$ 5.2940	$ 76,725	$ 4.0860	$ 59,217	$ 17,508
08/10/10	8,696	$ 4.9870	$ 43,365	$ 4.0860	$ 35,530	$ 7,835
08/10/10	2,899	$ 4.9880	$ 14,458	$ 4.0860	$ 11,843	$ 2,615
08/10/10	5,797	$ 4.9890	$ 28,922	$ 4.0860	$ 23,687	$ 5,235
08/10/10	14,493	$ 4.9900	$ 72,319	$ 4.0860	$ 59,217	$ 13,102
09/27/10	23,188	$ 4.3120	$ 99,988	$ 4.0860	$ 94,747	$ 5,242
09/27/10	5,797	$ 4.3130	$ 25,003	$ 4.0860	$ 23,687	$ 1,316
10/07/10	11,594	$ 4.2450	$ 49,217	$ 4.0860	$ 47,373	$ 1,844
10/07/10	14,493	$ 4.2460	$ 61,536	$ 4.0860	$ 59,217	$ 2,319
	200,000		$ 1,009,901		$ 817,192	$ 192,710
			$ 5.0495		$ 4.0860	$ 0.9635

Feb-10 (28)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/24/10	6,875	$ 5.2550	$ 36,128	$ 4.0812	$ 28,058	$ 8,070
05/24/10	3,438	$ 5.2560	$ 18,068	$ 4.0812	$ 14,029	$ 4,038
05/24/10	13,750	$ 5.2570	$ 72,284	$ 4.0812	$ 56,117	$ 16,167
06/10/10	30,937	$ 5.5990	$ 173,219	$ 4.0812	$ 126,262	$ 46,957
07/29/10	20,625	$ 5.2390	$ 108,054	$ 4.0812	$ 84,175	$ 23,879
08/09/10	13,750	$ 4.9990	$ 68,736	$ 4.0812	$ 56,117	$ 12,620
09/29/10	10,313	$ 4.3150	$ 44,498	$ 4.0812	$ 42,087	$ 2,411
10/07/10	10,313	$ 4.2630	$ 43,962	$ 4.0812	$ 42,087	$ 1,875
Total	110,000		$ 564,950		$ 448,933	$ 116,016
WACOG			$ 5.1359		$ 4.0812	$ 1.0547

Mar-11 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/14/10	31,809	$ 5.4850	$ 174,470	$ 3.9859	$ 126,785	$ 47,685
05/14/10	7,340	$ 5.4880	$ 40,284	$ 3.9859	$ 29,258	$ 11,026
06/21/10	46,489	$ 5.5150	$ 256,389	$ 3.9859	$ 185,301	$ 71,088
07/29/10	19,574	$ 5.1410	$ 100,632	$ 3.9859	$ 78,021	$ 22,611
07/29/10	24,468	$ 5.1420	$ 125,815	$ 3.9859	$ 97,527	$ 28,288
08/19/10	4,894	$ 4.7080	$ 23,039	$ 3.9859	$ 19,505	$ 3,534
08/19/10	4,894	$ 4.7090	$ 23,044	$ 3.9859	$ 19,505	$ 3,539
08/19/10	26,915	$ 4.7100	$ 126,769	$ 3.9859	$ 107,280	$ 19,490
09/27/10	31,809	$ 4.2640	$ 135,631	$ 3.9859	$ 126,785	$ 8,847
10/07/10	26,915	$ 4.2350	$ 113,985	$ 3.9859	$ 107,280	$ 6,705
10/07/10	4,894	$ 4.2390	$ 20,744	$ 3.9859	$ 19,505	$ 1,239
	230,000		$ 1,140,802		$ 916,752	$ 224,050
			$ 4.9600		$ 3.9859	$ 0.9741

Total

	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
	107,457	$ 5.2503	$ 564,186	$ 3.8314	$ 411,716	$ 152,470
	21,798	$ 5.3634	$ 116,912	$ 3.8810	$ 84,599	$ 32,313
	103,740	$ 5.4258	$ 562,878	$ 3.8174	$ 396,022	$ 166,856
	99,459	$ 5.2350	$ 520,671	$ 3.8379	$ 381,715	$ 138,956
	116,309	$ 5.2021	$ 605,048	$ 3.8822	$ 451,540	$ 153,509
	98,580	$ 4.8328	$ 476,419	$ 3.8409	$ 378,631	$ 97,788
	48,162	$ 4.7257	$ 227,599	$ 3.8933	$ 187,511	$ 40,089
	73,427	$ 4.5043	$ 330,742	$ 3.8597	$ 283,407	$ 47,335
	59,301	$ 4.5344	$ 268,893	$ 3.9935	$ 236,817	$ 32,076
	48,611	$ 4.3227	$ 210,130	$ 3.9832	$ 193,625	$ 16,505
	7,792	$ 4.5176	$ 35,202	$ 4.0231	$ 31,349	$ 3,853
	5,797	$ 4.9890	$ 28,922	$ 4.0860	$ 23,687	$ 5,235
	14,493	$ 4.9900	$ 72,319	$ 4.0860	$ 59,217	$ 13,102
	23,188	$ 4.3120	$ 99,988	$ 4.0860	$ 94,747	$ 5,242
	5,797	$ 4.3130	$ 25,003	$ 4.0860	$ 23,687	$ 1,316
	11,594	$ 4.2450	$ 49,217	$ 4.0860	$ 47,373	$ 1,844
	14,493	$ 4.2460	$ 61,536	$ 4.0860	$ 59,217	$ 2,319
	860,000		$ 4,255,666		$ 3,344,859	$ 908,488
			$ 4.9484		$ 3.8894	$ 1.0564

MINNESOTA ENERGY RESOURCES - NMU

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

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

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

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

Month/ Year	K#118657 NNG Storage	Storage K#121292 LS Power	Total NNG Storage	NNG PNG Volumes	NNG NMU Volumes	NNG Total Volumes	Projected K#118657 NNG WACOG	Projected K#121292 NNG WACOG	WACOG NNG PNG Cost	WACOG NNG NMU Cost	WACOG NNG Total Cost	NNG Indexes Price	NNG Index NNG PNG Cost	NNG Index NNG NMU Cost	NNG Index NNG Total Cost
Nov-10	455,259	39,000	494,259	429,894	44,865	474,759	$ 4.0923	$ 4.0923	$ 1,759,251	$ 183,601	$ 1,942,852	$ 3.6890	$ 1,585,879	$ 165,507	$ 1,751,386
Dec-10	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.0684	$ 4,394,846	$ 458,656	$ 4,853,502
Jan-11	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.3351	$ 4,683,028	$ 488,731	$ 5,171,759
Feb-11	1,143,984	98,000	1,241,984	1,080,247	112,737	1,192,984	$ 4.0923	$ 4.0923	$ 4,420,684	$ 461,353	$ 4,882,037	$ 4.3571	$ 4,706,747	$ 491,207	$ 5,197,953
Mar-11	455,259	39,000	494,259	429,894	44,865	474,759	$ 4.0923	$ 4.0923	$ 1,759,251	$ 183,601	$ 1,942,852	$ 4.2157	$ 1,812,301	$ 189,137	$ 2,001,438
Total	4,342,470	372,000	4,714,470	4,100,529	427,941	4,528,470	$ 4.0923	$ 4.0923	$ 16,780,555	$ 1,751,259	$ 18,531,814	$ 4.1904	$ 17,182,800	$ 1,793,238	$18,976,038
									$ 4.0923	$ 4.0923	$ 3.9308		$ 4.1904	$ 4.1904	$ 4.1904

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total Nexen Volumes	GLGT/VGT Centra AECO Storage WACOG	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total Nexen Cost
Nov-10	94,773	15,429	27,626	12,846	21,064	17,808	94,773	$ 3.7863	$ 58,420	$ 104,600	$ 48,637	$ 79,753	$ 67,427	$ 358,837
Dec-10	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 3.7863	$ 160,327	$ 287,063	$ 133,481	$ 218,875	$ 185,048	$ 984,793
Jan-11	260,095	42,344	75,817	35,254	57,807	48,873	260,095	$ 3.7863	$ 160,327	$ 287,063	$ 133,481	$ 218,875	$ 185,048	$ 984,793
Feb-11	234,925	38,246	68,480	31,842	52,213	44,144	234,925	$ 3.7863	$ 144,811	$ 259,283	$ 120,563	$ 197,694	$ 167,140	$ 889,492
Mar-11	97,932	15,944	28,547	13,274	21,766	18,402	97,932	$ 3.7863	$ 60,367	$ 108,086	$ 50,259	$ 82,411	$ 69,675	$ 370,798
Total	947,820	154,307	276,286	128,469	210,657	178,101	947,820	$ 3.7863	$ 584,251	$ 1,046,095	$ 486,421	$ 797,607	$ 674,339	$ 3,588,712
		16.28%	29.15%	13.55%	22.23%	18.79%	100.00%		$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863	$ 3.7863

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

MINNESOTA ENERGY RESOURCES - PNG

Projected Call Option Costs - November 2010 through March 201:

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-10

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

Dec-10

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

Jan-11

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

Feb-11

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

Mar-11

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

Total

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			87	870,000	$ 5.4253	$ 4,720,000	$ 4.3205	$ 3,758,830	$ 4.3205	$ 3,758,830	$ -	$ 0.5387	$ 468,700	$ 4,227,530
2			102	1,020,000	$ 5.6225	$ 5,735,000	$ 4.3263	$ 4,412,810	$ 4.3263	$ 4,412,810	$ -	$ 0.6212	$ 633,650	$ 5,046,460
3			104	1,040,000	$ 5.4279	$ 5,645,000	$ 4.3297	$ 4,502,890	$ 4.3297	$ 4,502,890	$ -	$ 0.5555	$ 577,700	$ 5,080,590
4			118	1,180,000	$ 4.7203	$ 5,570,000	$ 4.3161	$ 5,093,010	$ 4.3161	$ 5,093,010	$ -	$ 0.3494	$ 412,250	$ 5,505,260
5			122	1,220,000	$ 4.7295	$ 5,770,000	$ 4.3166	$ 5,266,310	$ 4.3181	$ 5,268,110	$ (1,800)	$ 0.2451	$ 299,050	$ 5,565,360
6			125	1,250,000	$ 4.4240	$ 5,530,000	$ 4.3202	$ 5,400,210	$ 4.3215	$ 5,401,920	$ (1,710)	$ 0.1801	$ 225,100	$ 5,625,310
7														
8														
9														
10														
Total			658	6,580,000		$ 32,970,000		$ 28,434,060		$ 28,437,570	$ (3,510)		$ 2,616,450	$ 31,050,510
						$ 5.0106		$ 4.3213		$ 4.3218	$ (0.0005)		$ 0.3976	$ 4.7189
NNG-PNG	472	71.73%	472	4,720,031	$ 5.0106	$ 23,650,370	$ 4.3213	$ 20,396,604	$ 4.3218	$ 20,399,122	$ (2,518)	$ 0.3976	$ 1,876,858	$ 22,273,462
NNG-NMU	59	8.97%	59	590,029	$ 5.0106	$ 2,956,420	$ 4.3213	$ 2,549,682	$ 4.3218	$ 2,549,997	$ (315)	$ 0.3976	$ 234,617	$ 2,784,299
GLGT-PNG	20	3.04%	20	200,032	$ 5.0106	$ 1,002,288	$ 4.3213	$ 864,395	$ 4.3218	$ 864,502	$ (107)	$ 0.3976	$ 79,540	$ 943,936
GLGT-NMU	38	5.78%	38	379,995	$ 5.0106	$ 1,904,018	$ 4.3213	$ 1,642,067	$ 4.3218	$ 1,642,270	$ (203)	$ 0.3976	$ 151,100	$ 1,793,167
VGT-PNG	17	2.58%	17	170,027	$ 5.0106	$ 851,945	$ 4.3213	$ 734,736	$ 4.3218	$ 734,827	$ (91)	$ 0.3976	$ 67,609	$ 802,345
VGT-NMU	28	4.26%	28	279,979	$ 5.0106	$ 1,402,874	$ 4.3213	$ 1,209,869	$ 4.3218	$ 1,210,019	$ (149)	$ 0.3976	$ 111,330	$ 1,321,199
Centra	24	3.65%	24	239,973	$ 5.0106	$ 1,202,416	$ 4.3213	$ 1,036,990	$ 4.3218	$ 1,037,118	$ (128)	$ 0.3976	$ 95,422	$ 1,132,412
Total	658	100.0%	658	6,580,066	$ 5.0106	$ 32,970,330	$ 4.3213	$ 28,434,344	$ 4.3218	$ 28,437,854	$ (3,510)	$ 0.3976	$ 2,616,476	$ 31,050,821