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November 4, 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. G007/M-10-1166

Dear Dr. Haar:

On November 1, 2010 Minnesota Energy Resources Corporation-NMU (MERC) filed its Petition for Approval of a Change in Demand Entitlement. Subsequent to filing, MERC discovered an error in the total filed Design Day capacity for NMU-GLGT. The original filing indicated there was 20,046 Mcf allocated to NMU-GLGT but the correct allocation is 16,446 Mcf as calculated in the revised Attachment 4, page 2 of 6.

MERC's Revised Petition for Approval of a Change in Demand Entitlement is attached. MERC is also refiled the Attachments to its Petition, with revisions made to the following attachments:

Attachment 3

Attachment 4, Page 1

Attachment 4, Page 2

Attachment 4, Page 4

Attachment 4, Page 5

Attachment 6

Attachment 7, Page 1

Attachment 7, Page 2

Attachment 8

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Please note that Attachments 5 and 10 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.

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

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. G007/M-10-1166
Change in Demand Entitlement)

REVISED 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	18.31%	4.70%	13.61%

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 16,446 Mcf as calculated in Attachment 4, page 2 of 6.¹

The difference between the total Design Day requirement and total Design Day capacity results in a 9.90% 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.

¹ MERC initially filed its Demand Entitlement filing on November 1, 2010 but subsequently discovered an error in the total filed Design Day capacity for NMU-GLGT. The original filing indicated there was 20,046 Mcf allocated to NMU-GLGT but the correct number is 16,446 Mcf as calculated in the revised Attachment 4, page 2 of 6.

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 6.

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:

<u>Station</u>	<u>Date</u>	<u>Avg. Temp</u>	<u>Avg. Wind</u>	<u>HDD65</u>	<u>AHDD65</u>
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 AHDD65².
 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.

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

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

III. Volume Risk Adjustments

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

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

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

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

from monthly billing records³. An unfortunate, but unavoidable consequence was that this data was based on monthly billing cycles that introduce billing lag, meter read lag (not all meters were read every month, resulting in billing cycle estimates and reversals), and other potential errors into their volumes.

A database of volumes billed for all customers from the prior winter was obtained. The database contained detail by customer class⁴, 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

³ Individual daily volumes were available for a handful of paper mills, direct-connects, taconites, and off-system end users.

⁴ Transportation, Interruptible, Joint Interruptible, Residential, Large Commercial & Industrial and Small Commercial & Industrial.

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

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

N. Maximum Daily Quantity (MDQ):

The amount calculated by dividing the volumes consumed by a particular customer during the highest historical peak month of usage for that customer by twenty (20).

Company will estimate a peak month for new customers. A Maximum Daily Quantity may also be established through direct measurement or other means (i.e. estimating the peak day requirements after installation of new processing equipment or more energy efficient heating systems) if approved by [the] Company.

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

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

C. Apply Sales Forecast Growth Rates

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

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

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 NORTSHORE
- 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. MERC's Specific NMU Proposed Demand-Related Changes

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC'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. Financial Option Units and Premiums

- i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2010/2011 winter (November through March). Please see Attachment 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. Gas Supply.

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. Price Volatility

MERC's hedging strategy as described in section 2.(D).(vii.) provides the opportunity to ensure MERC customers are seventy percent (70%) hedged assuming normal winter volumes. The 70% hedged is accomplished by 40% of normal winter volumes hedged by a fixed price, which is comprised of storage and futures contracts.

MERC is projecting the weighted average cost of gas (WACOG) for futures contracts of natural gas to be approximately \$4.9484. 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. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2010. Rate impacts associated with this change can be found on Attachment 4, pages 1 through 3, and on page 1 of Attachment 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 4, 2010

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern

Michael J. Ahern

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Minneapolis, MN 55402-1498

Telephone: (612) 340-2600

Attorney for Minnesota Energy
Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Sarah J. Sorenson, being first duly sworn on oath, deposes and states that on the 4th day of November, 2010, the Revised 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 the cover letter 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 4th 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		% of total load	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	2008/09 Customer Growth	Total
			Intercept	Slope						
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 subtracts 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**

<u>Heating Season</u>	<u>No. of Firm Customers</u>	<u>Design Day Requirements</u>	<u>MMBtus /Customer /Day</u>
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

MINNESOTA ENERGY RESOURCES - NMU

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

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

MINNESOTA ENERGY RESOURCES - NMU

ENTITLEMENT LEVELS

PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2010

<u>Type of Capacity or Entitlement</u>		<u>Current Amount Mcf or MMBtu</u>	<u>Proposed Change Mcf or MMBtu</u>	<u>Proposed Amount Mcf or MMBtu</u>
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*		<u>0</u>	<u>0</u>	<u>0</u>
NNG Subtotal		<u>23,611</u>	<u>4,436</u>	<u>28,047</u>
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		<u>63,783</u>	<u>8,036</u>	<u>71,819</u>
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	\$1.2555	9.94%	10.14%	22.88%	\$0.2337	
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	\$7.2655	-39.37%	-47.13%	3.34%	\$0.2347	
Avg Annual Cost	\$1,677.68	\$1,401.47	\$993.78	\$984.31	\$1,017.18	-39.37%	-47.13%	3.34%	\$32.86	
Effect of proposed commodity change on average annual bills:									\$0.14	
Effect of proposed demand change on average annual bills:									\$32.72	

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	\$1.2555	9.94%	12.09%	22.88%	\$0.2337	
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	\$7.4022	-38.23%	-26.06%	5.28%	\$0.3714	
Avg Annual Cost	\$82,889.18	\$69,242.63	\$49,099.63	\$48,632.04	\$51,201.31	-38.23%	-26.06%	5.28%	\$2,569.27	
Effect of proposed commodity change on average annual bills:									\$6.92	
Effect of proposed demand change on average annual bills:									\$1,616.79	

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	Season	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	Rate Case Sales (therms)																																																																																																																																																																																	
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	\$4.5800	\$ 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	2,138	5	\$3.4580	\$ 36,966	54,901,770 \$0.00067																																																																																																																																																																																
FT Wester Zone	FT8466	Annual	3,000	12	\$3.4580	\$ 124,488	54,901,770 \$0.00227																																																																																																																																																																																
GLGT Demand					\$	630,690	54,901,770 \$0.01149																																																																																																																																																																																
Centra																																																																																																																																																																																							
CENTRA TRANSMISSION (\$Cdn/103M3)					\$166.3160																																																																																																																																																																																		
Conversion ((((\$Cdm103M3)*279.256)/9858))*1	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					\$	6,893,148	\$0.12555																																																																																																																																																																																
For Joint Rate Demand					54,901,770	Annual Firm Sales in therms																																																																																																																																																																																	
<table border="1"> <thead> <tr> <th></th> <th>Units Dth's</th> <th>Months</th> <th>Annual Dth's</th> </tr> </thead> <tbody> <tr> <td colspan="4">Northern Natural Gas (NNG)</td> </tr> <tr> <td>TF12B (Max Rate)</td> <td>4,232</td> <td>12</td> <td>50,784</td> </tr> <tr> <td>TF12V (Max Rate)</td> <td>3,919</td> <td>12</td> <td>47,028</td> </tr> <tr> <td>TF5 (Max Rate)</td> <td>3,493</td> <td>5</td> <td>17,465</td> </tr> <tr> <td>TF12B (Discount-Winter)</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>TF5 (Discount-Winter)</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>649</td> <td>5</td> <td>3,245</td> </tr> <tr> <td>TFX12 (Max Rate)</td> <td>1,171</td> <td>12</td> <td>14,052</td> </tr> <tr> <td>TFX Apr (Max Rate)</td> <td>216</td> <td>1</td> <td>216</td> </tr> <tr> <td>TFX Oct (Max Rate)</td> <td>216</td> <td>1</td> <td>216</td> </tr> <tr> <td>TFX5 (Max Rate)</td> <td>6,208</td> <td>5</td> <td>31,040</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>195</td> <td>5</td> <td>975</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>139</td> <td>12</td> <td>1,668</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>895</td> <td>12</td> <td>10,740</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>1,290</td> <td>12</td> <td>15,480</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>41</td> <td>5</td> <td>205</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>265</td> <td>5</td> <td>1,325</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>2,401</td> <td>5</td> <td>12,005</td> </tr> <tr> <td>Bison</td> <td>5,411</td> <td>11</td> <td>56,816</td> </tr> <tr> <td>NBPL</td> <td>5,411</td> <td>11</td> <td>56,816</td> </tr> <tr> <td>LS Power</td> <td>3,149</td> <td>3</td> <td>9,447</td> </tr> <tr> <td>WINDOM</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>SMS</td> <td>2,454</td> <td>12</td> <td>29,448</td> </tr> <tr> <td colspan="4">Viking (VGT)</td> </tr> <tr> <td>FT-A ZONE 1 - 1</td> <td>7,966</td> <td>12</td> <td>95,592</td> </tr> <tr> <td>FT-A ZONE 1 - 1</td> <td>0</td> <td>4</td> <td>-</td> </tr> <tr> <td>NNG-TF12 Base</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TF12 Variable</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TF5 Chisago</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>NNG-TFX 12 Chisago</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TFX 5 Chisago</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>Wadena Delivered Option</td> <td>5,902</td> <td>3</td> <td>17,706</td> </tr> <tr> <td colspan="4">Great Lakes (GLGT)</td> </tr> <tr> <td>FT-A</td> <td>10,130</td> <td>12</td> <td>121,560</td> </tr> <tr> <td>FT Western Zone (12)</td> <td>1,178</td> <td>12</td> <td>14,136</td> </tr> <tr> <td>FT Western Zone (5)</td> <td>2,138</td> <td>5</td> <td>10,690</td> </tr> <tr> <td>FT Wester Zone</td> <td>3,000</td> <td>12</td> <td>36,000</td> </tr> <tr> <td colspan="4">Centra</td> </tr> <tr> <td>CENTRA TRANSMISSION</td> <td></td> <td></td> <td></td> </tr> <tr> <td>Conversion ((((\$Cdm103M3)*279.256)/9858))*9537</td> <td>9,858</td> <td>12</td> <td>118,296</td> </tr> <tr> <td>Union Balancing</td> <td>4,500</td> <td>12</td> <td>54,000</td> </tr> <tr> <td>CENTRA MINNESOTA PIPELINES</td> <td>9,858</td> <td>12</td> <td>118,296</td> </tr> </tbody> </table>									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)	2,138	5	10,690	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
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Total Demand Cost					\$	6,893,148																																																																																																																																																																																	
Total Demand Weighted Vol in Mcf						7,729,500																																																																																																																																																																																	
Total Joint Demand Rate \$/Mcf							\$0.89180																																																																																																																																																																																

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 TRANSV (\$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	\$1.0069	-11.83%	-12.06%	-1.46%	(\$0.0149)
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	\$7.2205	-39.75%	-47.58%	2.70%	\$0.1897
Avg Annual Cost	\$1,677.68	\$1,401.47	\$993.78	\$984.31	\$1,010.87	-39.75%	-47.58%	2.70%	\$26.56
Effect of proposed commodity change on average annual bills:									\$28.65
Effect of proposed demand change on average annual bills:									(\$2.09)
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	\$1.0069	-11.83%	-10.11%	-1.46%	(\$0.0149)
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	\$7.2205	-39.75%	-27.87%	2.70%	\$0.1897
Avg Annual Cost	\$82,889.18	\$69,242.63	\$49,099.63	\$48,632.04	\$49,944.39	-39.75%	-27.87%	2.70%	\$1,312.35
Effect of proposed commodity change on average annual bills:									\$1,415.62
Effect of proposed demand change on average annual bills:									(\$103.27)
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							Cost/Ccf																																																																																																																																																																																																								
Contract Type	Season	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	Rate Case Sales (therms)																																																																																																																																																																																																									
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	\$4.5800	\$ 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																																																																																																																																																																																																								
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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																																																																																																																																																																																																								
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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	2,138	5	\$3.4580	\$ 36,966	54,901,770 \$0.00067																																																																																																																																																																																																								
FT Wester Zone	FT8466	Annual	3,000	12	\$3.4580	\$ 124,488	54,901,770 \$0.00227																																																																																																																																																																																																								
GLGT Demand					\$	630,690	54,901,770 \$0.01149																																																																																																																																																																																																								
Centra																																																																																																																																																																																																															
CENTRA TRANSMISSION (\$Cdn/103M3)					\$166.3160																																																																																																																																																																																																										
Conversion ((((\$Cdm103M3)*279.256)/9858))*1	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					\$	5,527,894	\$0.10069																																																																																																																																																																																																								
For Joint Rate Demand					\$	54,901,770	Annual Firm Sales in therms																																																																																																																																																																																																								
<table border="1"> <thead> <tr> <th></th> <th>Units Dth's</th> <th>Months</th> <th>Annual Dth's</th> </tr> </thead> <tbody> <tr> <td colspan="4">Northern Natural Gas (NNG)</td> </tr> <tr> <td>TF12B (Max Rate)</td> <td>4,232</td> <td>12</td> <td>50,784</td> </tr> <tr> <td>TF12V (Max Rate)</td> <td>3,919</td> <td>12</td> <td>47,028</td> </tr> <tr> <td>TF5 (Max Rate)</td> <td>3,493</td> <td>5</td> <td>17,465</td> </tr> <tr> <td>TF12B (Discount-Winter)</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>TF5 (Discount-Winter)</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>649</td> <td>5</td> <td>3,245</td> </tr> <tr> <td>TFX12 (Max Rate)</td> <td>1,171</td> <td>12</td> <td>14,052</td> </tr> <tr> <td>TFX Apr (Max Rate)</td> <td>216</td> <td>1</td> <td>216</td> </tr> <tr> <td>TFX Oct (Max Rate)</td> <td>216</td> <td>1</td> <td>216</td> </tr> <tr> <td>TFX5 (Max Rate)</td> <td>6,208</td> <td>5</td> <td>31,040</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>195</td> <td>5</td> <td>975</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>139</td> <td>12</td> <td>1,668</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>895</td> <td>12</td> <td>10,740</td> </tr> <tr> <td>TFX12 (Discount)</td> <td>1,290</td> <td>12</td> <td>15,480</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>41</td> <td>5</td> <td>205</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>265</td> <td>5</td> <td>1,325</td> </tr> <tr> <td>TFX5 (Discount)</td> <td>2,401</td> <td>5</td> <td>12,005</td> </tr> <tr> <td>Bison</td> <td>5,411</td> <td>11</td> <td>56,816</td> </tr> <tr> <td>NBPL</td> <td>5,411</td> <td>11</td> <td>56,816</td> </tr> <tr> <td>LS Power</td> <td>3,149</td> <td>3</td> <td>9,447</td> </tr> <tr> <td>WINDOM</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>SMS</td> <td>2,454</td> <td>12</td> <td>29,448</td> </tr> <tr> <td colspan="4">Viking (VGT)</td> </tr> <tr> <td>FT-A ZONE 1 - 1</td> <td>7,966</td> <td>12</td> <td>95,592</td> </tr> <tr> <td>FT-A ZONE 1 - 1</td> <td>0</td> <td>4</td> <td>-</td> </tr> <tr> <td>NNG-TF12 Base</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TF12 Variable</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TF5 Chisago</td> <td>0</td> <td>5</td> <td>-</td> </tr> <tr> <td>NNG-TFX 12 Chisago</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>NNG-TFX 5 Chisago</td> <td>0</td> <td>12</td> <td>-</td> </tr> <tr> <td>Wadena Delivered Option</td> <td>5,902</td> <td>3</td> <td>17,706</td> </tr> <tr> <td colspan="4">Great Lakes (GLGT)</td> </tr> <tr> <td>FT-A</td> <td>10,130</td> <td>12</td> <td>121,560</td> </tr> <tr> <td>FT Western Zone (12)</td> <td>1,178</td> <td>12</td> <td>14,136</td> </tr> <tr> <td>FT Western Zone (5)</td> <td>2,138</td> <td>5</td> <td>10,690</td> </tr> <tr> <td>FT Wester Zone</td> <td>3,000</td> <td>12</td> <td>36,000</td> </tr> <tr> <td colspan="4">Centra</td> </tr> <tr> <td>CENTRA TRANSMISSION</td> <td></td> <td></td> <td></td> </tr> <tr> <td>Conversion ((((\$Cdm103M3)*279.256)/9858))*1</td> <td>9,858</td> <td>12</td> <td>118,296</td> </tr> <tr> <td>Union Balancing</td> <td>4,500</td> <td>12</td> <td>54,000</td> </tr> <tr> <td>CENTRA MINNESOTA PIPELINES</td> <td>9,858</td> <td>12</td> <td>118,296</td> </tr> <tr> <td colspan="5">Total Demand Cost</td> <td>\$</td> <td>5,527,894</td> <td></td> </tr> <tr> <td colspan="5">Total Demand Weighted Vol in Mcf</td> <td></td> <td>7,729,500</td> <td></td> </tr> <tr> <td colspan="5">Total Joint Demand Rate \$/Mcf</td> <td></td> <td></td> <td>\$0.71517</td> </tr> </tbody> </table>									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)	2,138	5	10,690	FT Wester Zone	3,000	12	36,000	Centra				CENTRA TRANSMISSION				Conversion ((((\$Cdm103M3)*279.256)/9858))*1	9,858	12	118,296	Union Balancing	4,500	12	54,000	CENTRA MINNESOTA PIPELINES	9,858	12	118,296	Total Demand Cost					\$	5,527,894		Total Demand Weighted Vol in Mcf						7,729,500		Total Joint Demand Rate \$/Mcf							\$0.71517
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FT-A ZONE 1 - 1	7,966	12	95,592																																																																																																																																																																																																												
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NNG-TF12 Base	0	12	-																																																																																																																																																																																																												
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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

NNG		Season	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate (\$/therm)	
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
AECO		Season	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate (\$/therm)	
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									
NNG	Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm				
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

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)

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

Units - Call Options (Daily Volume)

	<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Daily Total</u>	<u>Term Total</u>
	<u>Contract Date</u>	<u>Daily Volume</u>	<u>Contract Date</u>	<u>Daily Volume</u>	<u>Contract Date</u>	<u>Daily Volume</u>	<u>Contract Date</u>	<u>Daily Volume</u>	<u>Contract Date</u>	<u>Daily Volume</u>		
1												-
2												-
3												-
4												-
5												-
6												-
Total		<u>7,333</u>		<u>10,968</u>		<u>11,613</u>		<u>11,071</u>		<u>8,387</u>	<u>49,373</u>	<u>1,490,000</u>
		<u>220,000</u>		<u>340,000</u>		<u>360,000</u>		<u>310,000</u>		<u>260,000</u>		<u>1,490,000</u>

Premium - Call Option (Monthly Cost)

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

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES - NMU

	G007/					
	M-06- NMU GS	M-07-1402 NMU GS	M-08-1329 NMU GS	M-09- NMU GS	M-10- NMU GS	Proposed Change
NNG Design Day	21,635	21,491	21,791	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%
<u>NNG Allocated Entitlements in PGA</u>						
TF12B	7,340	2,954	2,653	7,513	4,232	-3,281
TF12V	5,930	9,802	6,643	5,243	3,919	-1,324
TF(5)	2,102	1,991	5,451	1,991	3,493	1,502
TFX(12)	0	0	0	0	3,495	
TFX(5)	5,514	6,139	6,139	6,139	9,759	3,620
LS Power		2,725	2,777	2,725	3,149	424
TFX(5)	0	0	0	0	0	0
Peak Capacity 3 mo.	0	0	0	0	0	0
Total NNG Allocated Entitlements in PGA	20,886	23,611	23,663	23,611	28,047	941
<u>Other Pipelines Entitlements in PGA</u>						
Viking FT-A	7,966	7,966	7,966	7,966	7,966	0
Viking FT-A Backhaul	4,625	5,902	5,902	5,902	0	-5,902
Viking/NNG Chisago TF12 Base	1,821	782	926	1,368	0	-1,368
Viking/NNG Chisago TF12 Variable	0	0	0	955	0	-955
Viking/NNG Chisago TF5	441	1,765	2,089	563	0	-563
Viking/NNG Chisago TFX 12	725	1,963	2,324	2,089	0	-2,089
Viking/NNG Chisago TFX 5	1,637	476	563	926	0	-926
Great Lakes FT-A (12)	11,308	14,308	15,308	14,308	14,308	0
Great Lakes FT-A (5)	2,138	2,138	2,138	2,138	2,138	0
Centra FT-1	9,858	9,858	9,858	9,858	9,858	0
Centra -Boise	0	0	0	0	0	0
Nexen Exchange	6,000	0	0	0	0	0
Tenaska PSO GL	0	0	0	0	0	0
Tenaska PSO Centra	0	0	0	0	0	0
ANR Storage	0	0	0	0	0	0
Total Capacity	62,780	62,867	64,835	63,783	62,317	-1,466
Total NNG Transportation	20,886	23,611	23,663	23,611	28,047	4,436
Total Transportation	56,780	62,867	64,835	63,783	62,317	-1,466
Total Seasonal Transportation	7,616	10,855	14,367	10,855	19,896	9,041
Percent Seasonal on NNG	36.5%	46.0%	60.7%	46.0%	70.9%	25.0%
<u>Other Entitlements not included in Peak Day Deliverability</u>						
TFX Offpeak Old (Apr/Oct) one mo.	0	0	0	0	0	0
TFX (Apr/Oct) one mo.	0	0	0	0	0	0
TFX Apr.-Oct. 7 mos.	0	0	0	0	0	0
TFX May-Sept 5 mos.	0	0	0	0	0	0
FDD Storage reservation per mo.	6,343	7,619	7,980	7,830	9,516	1,686
FDD Storage capacity per mo.	365,682	428,702	460,070	451,428	548,602	97,174
ANR Capacity per mo.	0	0	0	0	0	0
Nexen PSO	600,000	684,604	684,604	684,604	0	-684,604
Tenaska PSO	15,807	17,763	17,763	0	0	0
AECO Storage	0	0	0	0	665,043	665,043
NGPL per mo.	0	0	0	0	0	0
SMS per mo.	1,907	2,172	2,143	2,103	2,454	351
SBA	0	0	0	0	0	0
Upstream Demand per mo.	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - NMU

Rate Impacts NMU

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	Nov 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^A	% Change From Last Demand Filing	% Change From Last PGA	\$ Change From Last PGA
General Service	G011/MR08-836^	M-08-XXXX	M-09-XXXX	Oct 1/10					
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	\$1.2555	9.94%	14.87%	22.88%	\$0.2337
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	\$7.2655	-39.37%	2.35%	3.34%	\$0.2347
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas	\$1,677.68	\$1,401.47	\$993.78	\$984.31	\$1,017.18	-39.37%	2.35%	3.34%	\$32.86

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^A	% Change From Last Demand Filing	% Change From Last PGA	\$ Change From Last PGA
Large General Service	G011/MR08-836^	M-07-XXXX	M-08-XXXX	Oct 1/09					
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	\$1.2555	9.94%	14.87%	22.88%	\$0.2337
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	\$7.4022	-38.23%	4.28%	5.28%	\$0.3714
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	\$51,201.31	-38.23%	4.28%	5.28%	\$2,569.27

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^A	% Change From Last Demand Filing	% Change From Last PGA	\$ Change From Last PGA
SV Interruptible Service	G011/MR08-836^	M-07-XXXX	M-08-XXXX	Oct 1/09					
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

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	Nov 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^A	% Change From Last Demand Filing	% Change From Last PGA	\$ Change From Last PGA
LV Interruptible Service	G011/MR08-836^	M-07-XXXX	M-08-XXXX	Oct 1/09					
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

	Commodity Change \$/Mcf	Commodity Change %	Demand Change \$/Mcf	Demand Change \$/Mcf	Demand Change %	Total Change \$/Mcf	Total Change %	Average Annual Change
October Change Summary								
General Service	\$0.0010	0.10%	\$0.2288	\$0.2337	22.88%	\$0.2347	3.34%	\$32.86
Large General Service	\$0.0010	0.10%	\$0.2288	\$0.2337	22.88%	\$0.3714	5.28%	\$2,569.27
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

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	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
General Service	G011/MR08-836^	M-08-XXXX	M-09-XXXX	Oct 1/10					
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	\$1.0069	-11.83%	-7.88%	-1.46%	(\$0.0149)
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	\$7.2205	-39.75%	1.72%	2.70%	\$0.1897
Average Annual Use	140	140	140	140	140				
Average Annual Cost of Gas*	\$1,677.68	\$1,401.47	\$993.78	\$984.31	\$1,010.87	-39.75%	1.72%	2.70%	\$26.56

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	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
Large General Service	G011/MR08-836^	M-08-XXXX	M-08-XXXX	Oct 1/09					
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	\$1.0069	-11.83%	-7.88%	-1.46%	(\$0.0149)
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	\$7.2205	-39.75%	1.72%	2.70%	\$0.1897
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	\$49,944.39	-39.75%	1.72%	2.70%	\$1,312.35

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	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
SV Interruptible Service	G011/MR08-836^	M-08-XXXX	M-08-XXXX	Oct 1/09					
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

	Base Cost of Gas Change	Demand Change	Last Demand Change	Most Recent PGA	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
LV Interruptible Service	G011/MR08-836^	M-08-XXXX	M-08-XXXX	Oct 1/09					
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

	Commodity Change	Commodity Change	Demand Change	Demand Change	Demand Change	Total Change	Total Change	Average Annual Change
October Change Summary	\$/Mcf	%	\$/Mcf	\$/Mcf	%	\$/Mcf	%	Change
General Service	\$0.2047	20.47%	(\$0.0146)	(\$0.0149)	-1.46%	\$0.1897	2.70%	\$26.56
Large General Service	\$0.2047	20.47%	(\$0.0146)	(\$0.0149)	-1.46%	\$0.1897	2.70%	\$1,312.35
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 implemented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

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

	NMU				Months	Total Annual Cost		Total Annual Cost Change
	Oct. 2010 Entitlements	Nov. 2010 Entitlements	Entitlement Change	Oct. 2010 Rate		Oct. 2010 Total Annual Cost	Nov. 2010 Total Annual Cost	
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

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

NNG WINTER PLAN (NMU)
NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

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

Total

548,602

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES

GLGT/VGT/Centra WINTER PLAN (NMU)
NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

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

TRADE DATA SECRET ENDS]

STORAGE
No Storage

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

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

Purchase Date	30						31						31							
	Nov-10						Dec-10						Jan-11							
Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market	Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market	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	05/20/10	3,250	\$ 5.1600	\$ 16,770	\$ 3.9089	\$ 12,704	\$ 4,066	05/21/10	28,986	\$ 5.3350	\$ 154,638	\$ 4.0860	\$ 118,434	\$ 36,204
06/18/10	4,872	\$ 5.4020	\$ 26,317	\$ 3.4412	\$ 16,765	\$ 9,553	05/20/10	3,250	\$ 5.1610	\$ 16,773	\$ 3.9089	\$ 12,704	\$ 4,069	05/21/10	2,899	\$ 5.3370	\$ 15,470	\$ 4.0860	\$ 11,843	\$ 3,626
06/18/10	34,103	\$ 5.4040	\$ 184,290	\$ 3.4412	\$ 117,353	\$ 66,937	05/20/10	6,500	\$ 5.1620	\$ 33,553	\$ 3.9089	\$ 25,408	\$ 8,145	06/28/10	2,899	\$ 5.6450	\$ 16,362	\$ 4.0860	\$ 11,843	\$ 4,519
07/08/10	34,103	\$ 4.8260	\$ 164,579	\$ 3.4412	\$ 117,353	\$ 47,226	05/20/10	3,250	\$ 5.1630	\$ 16,780	\$ 3.9089	\$ 12,704	\$ 4,076	06/28/10	11,594	\$ 5.6460	\$ 65,461	\$ 4.0860	\$ 47,373	\$ 18,087
08/05/10	29,231	\$ 4.8000	\$ 140,308	\$ 3.4412	\$ 100,589	\$ 39,719	05/20/10	13,000	\$ 5.1640	\$ 67,132	\$ 3.9089	\$ 50,816	\$ 16,316	06/28/10	28,986	\$ 5.6490	\$ 163,739	\$ 4.0860	\$ 118,434	\$ 45,306
09/27/10	26,795	\$ 3.8710	\$ 103,723	\$ 3.4412	\$ 92,206	\$ 11,517	06/29/10	35,750	\$ 5.2840	\$ 188,903	\$ 3.9089	\$ 139,743	\$ 49,160	07/29/10	17,391	\$ 5.2910	\$ 92,017	\$ 4.0860	\$ 71,060	\$ 20,957
10/05/10	7,308	\$ 3.7240	\$ 27,214	\$ 3.4412	\$ 25,147	\$ 2,067	07/29/10	22,750	\$ 5.1650	\$ 117,504	\$ 3.9089	\$ 88,927	\$ 28,576	07/29/10	2,899	\$ 5.2920	\$ 15,339	\$ 4.0860	\$ 11,843	\$ 3,496
10/05/10	17,051	\$ 3.7250	\$ 63,516	\$ 3.4412	\$ 58,677	\$ 4,839	08/06/10	16,250	\$ 4.9940	\$ 81,152	\$ 3.9089	\$ 63,520	\$ 17,633	07/29/10	2,899	\$ 5.2930	\$ 15,342	\$ 4.0860	\$ 11,843	\$ 3,499
							09/14/10	13,000	\$ 4.3490	\$ 56,537	\$ 3.9089	\$ 50,816	\$ 5,721	07/29/10	14,493	\$ 5.2940	\$ 76,725	\$ 4.0860	\$ 59,217	\$ 17,508
							10/07/10	13,000	\$ 4.0600	\$ 52,780	\$ 3.9089	\$ 50,816	\$ 1,964	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
Total WACOG	190,000		\$ 892,128		\$ 653,825	\$ 238,303		130,000		\$ 647,884		\$ 508,156	\$ 139,728	200,000		\$ 1,009,901		\$ 817,192	\$ 192,710	
			\$ 4.6954		\$ 3.4412	\$ 1.2542				\$ 4.9837		\$ 3.9089	\$ 1.0748			\$ 5.0495		\$ 4.0860	\$ 0.9635	

Purchase Date	28						31						Total						
	Feb-10						Mar-11												
Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market	Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market	
05/24/10	6,875	\$ 5.2550	\$ 36,128	\$ 4.0812	\$ 28,058	\$ 8,070	05/14/10	31,809	\$ 5.4850	\$ 174,470	\$ 3.9859	\$ 126,785	\$ 47,685	107,457	\$ 5.2503	\$ 564,186	\$ 3.8314	\$ 411,716	\$ 152,470
05/24/10	3,438	\$ 5.2560	\$ 18,068	\$ 4.0812	\$ 14,029	\$ 4,038	05/14/10	7,340	\$ 5.4880	\$ 40,284	\$ 3.9859	\$ 29,258	\$ 11,026	21,798	\$ 5.3634	\$ 116,912	\$ 3.8810	\$ 84,599	\$ 32,313
05/24/10	13,750	\$ 5.2570	\$ 72,284	\$ 4.0812	\$ 56,117	\$ 16,167	06/21/10	46,489	\$ 5.5150	\$ 256,389	\$ 3.9859	\$ 185,301	\$ 71,088	103,740	\$ 5.4258	\$ 562,878	\$ 3.8174	\$ 396,022	\$ 166,856
06/10/10	30,937	\$ 5.5990	\$ 173,219	\$ 4.0812	\$ 126,262	\$ 46,957	07/29/10	19,574	\$ 5.1410	\$ 100,632	\$ 3.9859	\$ 78,021	\$ 22,611	99,459	\$ 5.2350	\$ 520,671	\$ 3.8379	\$ 381,715	\$ 138,956
07/29/10	20,625	\$ 5.2390	\$ 108,054	\$ 4.0812	\$ 84,175	\$ 23,879	07/29/10	24,468	\$ 5.1420	\$ 125,815	\$ 3.9859	\$ 97,527	\$ 28,288	116,309	\$ 5.2021	\$ 605,048	\$ 3.8822	\$ 451,540	\$ 153,509
08/09/10	13,750	\$ 4.9990	\$ 68,736	\$ 4.0812	\$ 56,117	\$ 12,620	08/19/10	4,894	\$ 4.7080	\$ 23,039	\$ 3.9859	\$ 19,505	\$ 3,534	98,580	\$ 4.8328	\$ 476,419	\$ 3.8409	\$ 378,631	\$ 97,788
09/29/10	10,313	\$ 4.3150	\$ 44,498	\$ 4.0812	\$ 42,087	\$ 2,411	08/19/10	4,894	\$ 4.7090	\$ 23,044	\$ 3.9859	\$ 19,505	\$ 3,539	48,162	\$ 4.7257	\$ 227,599	\$ 3.8933	\$ 187,511	\$ 40,089
10/07/10	10,313	\$ 4.2630	\$ 43,962	\$ 4.0812	\$ 42,087	\$ 1,875	08/19/10	26,915	\$ 4.7100	\$ 126,769	\$ 3.9859	\$ 107,280	\$ 19,490	73,427	\$ 4.5043	\$ 330,742	\$ 3.8597	\$ 283,407	\$ 47,335
							09/27/10	31,809	\$ 4.2640	\$ 135,631	\$ 3.9859	\$ 126,785	\$ 8,847	59,301	\$ 4.5344	\$ 268,893	\$ 3.9935	\$ 236,817	\$ 32,076
							10/07/10	26,915	\$ 4.2350	\$ 113,985	\$ 3.9859	\$ 107,280	\$ 6,705	48,611	\$ 4.3227	\$ 210,130	\$ 3.9832	\$ 193,625	\$ 16,505
							10/07/10	4,894	\$ 4.2390	\$ 20,744	\$ 3.9859	\$ 19,505	\$ 1,239	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
Total WACOG	110,000		\$ 564,950		\$ 448,933	\$ 116,016		230,000		\$ 1,140,802		\$ 916,752	\$ 224,050	860,000		\$ 4,255,666		\$ 3,344,859	\$ 908,488
			\$ 5.1359		\$ 4.0812	\$ 1.0547				\$ 4.9600		\$ 3.9859	\$ 0.9741			\$ 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

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 11) 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 Emerson 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

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

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

