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August 1, 2013

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System

Docket No. G011/M-13-___

Dear Dr. Haar:

In accordance with Minnesota Rule 7825.2910, subpart 2, please find enclosed Minnesota Energy Resources Corporation's (MERC) request to change demand entitlement. Please note that any updated information will be provided with MERC's November 1, 2013 filing. MERC is also filing Excel and PDF versions of the attachments.

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

Please contact me at 612-340-2881 if you have any questions regarding the information in this filing. Thank you for your attention to this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

ATTACHMENT 1

August 1, 2013

To: Service List

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

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation has filed a petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement for its Northern Natural Gas transmission system.

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

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

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

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

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

ATTACHMENT 2

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Betsy Wergin	Commissioner
Nancy Lange	Commissioner

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation	)	
for Approval of a Change in Demand	)	Docket No. G011/M-13-___
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC customers served off of the Northern Natural Gas Company (NNG or Northern) system. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation	)	
for Approval of a Change in Demand	)	Docket No. G011/M-13-___
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation- Consolidated (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NNG's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

This filing includes the following attachments:

Attachment 1: Notice of Availability.

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

Attachment 3: Petition for Change in Demand with Attachments.

Attachment 4: Affidavit of Service and Service List.

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

1. Summary of Filing

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

2. Service

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

3. General Filing Information

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

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

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

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

C. Date of the Filing and Proposed Effective Date

Date of filing: August 1, 2013
Proposed Effective Date: November 1, 2013

D. Statute Controlling Schedule for Processing the Filing

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

E. Utility Employee Responsible for the Filing

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

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

DATED: August 1, 2013

Respectfully Submitted,

DORSEY & WHITNEY LLP

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

Attorney for Minnesota Energy Resources Corporation

ATTACHMENT 3

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Betsy Wergin	Commissioner
Nancy Lange	Commissioner

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation	)	
for Approval of a Change in Demand	)	Docket No. G011/M-13-___
Entitlement for its Northern Natural Gas	)	
Transmission System	)	

PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation (MERC or the Company), a division of Integrys Energy Group, Inc. (TEG), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC's customers served off of the Northern Natural Gas Company (NNG or Northern) system.[1] MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

[1] MERC also serves Minnesota customers off of the MERC-Consolidated pipeline system (Centra Pipelines (Centra), Viking Gas Transmission (Viking) and Great Lakes Gas Transmission (GLGT)). MERC requests approval of a demand entitlement change for the 2013-2014 heating season for its MERC-Consolidated in a separate docket.

II. DISCUSSION

A. MERC's NNG Design Day Requirements

MERC's 2013-2014 NNG design day requirements increased 19,995 Mcf (or approximately 8.85 percent) from 211,182 Mcf to 200,785 Mcf.

Table 1: MERC's Proposed NNG Reserve Margins
For the 2013-2014 Heating Season

	Reserve Margin 2013-2014 Heating Season	Reserve Margin 2012-2013 Heating Season	Change
NNG Zone EF	3.09%	3.41%	-0.32%

As shown in Table 1, MERC's proposed system wide reserve margin, Zone EF for the 2013-2014 heating season is positive.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day requirement for Northern Natural Gas (NNG), is 245,878 Dth as calculated in Attachment 5 and Attachment 7 under the NNG Entitlement Allocation.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day capacity on Northern Natural Gas (NNG), is 253,485 Dth as calculated in Attachment 5 and Attachment 7 under the NNG Entitlement Allocation. The difference between the total Design Day requirement and total Design Day capacity results in a 3.09% positive reserve margin.

Demand Entitlement increased primarily due to purchasing a NNG Zone Delivery Call Option (20,000 Dth), which was not part of the portfolio in 2012/13. Please see Attachments 5 and 8 for calculated volumes by month.

B. <u>Forecast Methodology for MERC Demand Entitlement August 1, 2013</u>

<u>Peakday</u>

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's customers are served by <u>four pipelines:</u>

1. VGT - Viking Gas Transmission system
2. NNG- Northern Natural Gas pipeline
3. GLGT - Great Lakes Gas Transmission pipeline
4. Centra - Centra pipeline

Effective July 1, 2013, two Petitions for Change in Demand need to be filed (one for each PGA):

A. All MERC customers served off of NNG = NNG

B. All other PNG customers, served off of Centra, GLGT & VGT = MERC Consolidated

Before July 1, 2013, four Petitions for Change in Demand were filed (one for each PGA):

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

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

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

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

Weather data is obtained from eight weather stations:

International Falls, Bemidji, Cloquet, Fargo, Minneapolis, Rochester, Worthington and Ortonville.

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

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

Analytical Approach

Summary

1. Obtain daily weather data for each weather station
2. Obtain daily total throughput volumes by pipeline
3. Perform total throughput peak day regressions. In response to comments from the DOC (Minnesota Department of Commerce):
    a. Review and potentially change the regression methodology to mitigate the impact of autocorrelation.

b. Provide a reasonable explanation whenever we choose to use a regression model that does not have an intercept.

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

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

Station	**Date**	**Avg. Temp**	**Avg. Wind**	**HDD65**	**AHDD65**
Bemidji	2/1/1996	-34	8	99	107
Cloquet	2/2/1996	-31	7	96	103
Fargo	1/18/1996	-16	34	81	109

International Falls	2/1/1996	-34	8	99	107
Minneapolis	2/2/1996	-25	8	90	97
Rochester	2/2/1996	-27	10	92	101
Worthington	1/18/1996	-8	32	73	96
Ortonville	1/14/2009	-21	11	86	96

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

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

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

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

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

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[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.

5. In response to comments from the DOC (Minnesota Department of Commerce), review and potentially change the regression methodology to mitigate the impact of autocorrelation. See section below on autocorrelation.
6. In response to comments from the DOC, provide a reasonable explanation whenever we choose to use a regression model that does not have an intercept.
7. Summarize the Baseload and Use/AHDD65 from each regression.
8. 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).

Autocorrelation Review

In regression analysis using time series data, autocorrelation of the errors is a problem. Autocorrelation of the errors, which themselves are unobserved, can generally be detected because it produces autocorrelation in the observable residuals. (Errors are also known as "error terms" in econometrics.) Autocorrelation violates the ordinary least squares (OLS) assumption that the error terms are uncorrelated. While it does not bias the OLS coefficient estimates, the standard errors tend to be underestimated (and the t-scores overestimated) when the autocorrelations of the errors at low lags are positive. The traditional test for the presence of first-order autocorrelation is the Durbin–Watson statistic or, if the explanatory variables include a lagged dependent variable, Durbin's h statistic. To correct for this used we used the MetrixND software package to employ an AR(1) regression which then showed that the Durbin –Watson statistics are all either close to 2 or above. The AR (1) is similar to that of the Cochrane-Orcutt method to correct for autocorrelation.

III. Volume Risk Adjustments

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

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

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

In order to determine firm peak day load, volumes contained in the daily pipeline meter readings for interruptible, joint interruptible and transportation customers needed to be isolated and removed. While it would have been ideal to have daily billing data for all customers, most of the interruptible, transportation, and joint interruptible data was, in most cases, only available from monthly billing records[3]. 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 resulted in billing cycle estimates and reversals), and other potential errors into their volumes.

A database of volumes billed for all customers from the prior winter was obtained. The database contained detail by customer class[4], 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

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[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

providing billing services to MERC. Sales and Revenue Forecasting had previously adjusted the billing data to properly fit the appropriate calendar month of consumption by apportioning billed volumes, i.e. for a bill covering February 15 to March 15, volumes were split evenly between February and March.

Volumes for the interruptible, transportation and joint interruptible customer classes (INTER, TRANS and JINTER classes) needed to be mapped to the appropriate regression demand area, and were then summed. This billing data included consumption that was billed, but not included in the daily metered volumes for several large specific customers (paper mills, direct-connects, taconites, and off-system end users), and therefore needed to be removed from the gross interruptible, transportation and joint interruptible totals. Such customers were identified, mapped to the demand areas, summed and subtracted from the interruptible, transportation and joint interruptible customer classes totals. The following peak demand estimation method based on the highest monthly total from the prior winter was then used to calculate the amount to subtract from the results of the data regressions for each demand area:

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

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

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

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

C. Apply Sales Forecast Growth Rates

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

Exhibit 1

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

NMU-GLGT

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

NMU-VGT

Lamb Weston.

PNG-NNG

Taconites / Direct Connects =

- CCI EMPIRE IND DEL PT 2 TILDEN
- CCI NORTHSHORE
- UNITED TACONITE (was 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) =

- ASSOCIATED MILK PRODUCTS, INC.
- CORRECTIONAL CTR
- KEMPS LLC
- KERRY BIO-SCIENCE
- LAKESIDE
- MILK SPECIALTIES
- LAND OF LAKES
- PRO-CORN
- SWIFT
- SENECA FOODS-ROCHERSTER
- ENGINEERED POLYMERS
- SANDSTONE FEDERAL CORRECTIONAL INSTITUTE
- Glenville #1
- Agra Resources(Exol)
- Halcon Corporation

B. Daily Firm Capacity

PNG-VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL

PNG-GLGT

- AMERIPRIDE
- NORTHLAND APTS
- NW TECH COLLEGE - BEMIDJI

PNG-NNG

- HENDRICKS HOSPITAL
- GLASSTITE INC

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 13. 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 the NNG pipeline. The Design Day model only calculates firm volumes. MERC does not forecast on a daily/monthly basis utilizing the Design Day model. The Design Day model is utilized to calculate the theoretical peak day.

Average Customer Counts

In the 2007 demand entitlement dockets, MERC agreed to include average customer counts which is provided in Attachment 14.

C. <u>MERC's Specific PNG Proposed Northern System Demand-Related Changes</u>

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC- Northern (NNG) system 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- NNG proposes an increase of 20,000 Mcf/day in total heating season. The Company proposes changes to its portfolio of capacity services identified below in Table 4.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)	
TF12B & TF12V	763	Mcf/Day
TF5	(763)	Mcf/Day
TFX12	0	Mcf/Day
TFX5	0	Mcf/Day
TFX- (Apr) *	0	Mcf/Day
TFX- (Oct) *	0	Mcf/Day
Bison *	0	Mcf/Day
NBPL *	0	Mcf/Day
Northwestern Energy	0	Mcf/Day
NNG Zone Delivery Call Option	20,000	Mcf/Day

* Volumes not part of heating season volumes

MERC contracted for capacity on Bison Pipeline for 50,000 Dth/day which went into service on January 14, 2011. The contracted capacity with Northern Border Pipeline (NBPL) went into effect at the in-service of Bison. This capacity does not add any incremental capacity but is utilized to deliver Rockies supply to NNG customers at Northern Border Pipeline (NBPL) interconnects with NNG.

2. Other Demand Entitlement Changes

As shown in the Attachment 10, MERC- NNG proposes no change in TFX Apr and TFX Oct and no change in Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability.

D. Financial Units and Premiums

i. MERC is entering into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2013/2014 winter (November through March). MERC will be making purchases through October 2013. The Call Option contracts are projected for the entire 2013/2014 winter. Please see Attachment 8.

ii. Total premium costs to date entered into the financial Call Options on behalf of MERC's firm customers amounted to $758,741 for the 2013/2014 winter. MERC will update total premium costs in the November 1, 2013 filing. Please see Attachment 8.

iii. MERC will be entering into 497 contracts (10,000/contract) or 4,970,000. Total premium per contract to date is approximately $0.3109. MERC will update total premium costs in the November 1, 2013 filing. Please see Attachment 8.

iv. Please see attachment 8 for the various contract dates.

v. Please see attachment 8 for the various contract prices.

vi. MERC will be entering into 150 futures contracts (10,000/contract) or 1,500,000. MERC will update total futures purchased in the November 1, 2013 filing. Please see Attachment 8.

vii. MERC believes a diversified portfolio approach towards hedging is in the best interest of MERC's firm customers. MERC implemented a 40% fixed price (storage and futures contracts), 30% financial call options and 30% market based prices, assuming normal weather. A dollar-cost-averaging approach is utilized in purchasing the hedging portfolio.

Although this hedging strategy will most likely not provide the lowest priced supply, it does meet MERC's stated objectives of providing reliable and reasonably priced natural gas and mitigates natural gas price volatility. Please see Attachment 9, page 1 of 2.

E. Gas Supply.

The NNG 2013-2014 Winter Portfolio Plan - Minnesota Energy Resources Corporation for NNG gas supply purchases for the Hedging Plan is in Attachment 9, page 2.

F. Price Volatility

MERC 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 $4.1402. Please see Attachment 15, page 1 of 3. MERC is projecting the NNG Storage WACOG for PNG-NNG to be approximately $3.6991. . Please see Attachment 15, page 2 of 3. The remaining 30% of the 70% is hedged by financial call options. MERC purchased call options at an average strike price of $3.8830, which means if NYMEX contract(s) settle above that price, the options are exercised and MERC's customers gas cost is capped at the average strike price. Please see Attachment 15, 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 $4.16 for 70% of normal winter volumes assuming that the NYMEX prices are above the average strike price plus the physical index basis spread. If the NYMEX prices are below the average strike price, the average natural gas cost for 70% of the normal winter volumes will be lower. The remaining 30% of normal winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium or margin costs.

G. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2013. Rate impacts associated with this change can be found on Attachment 4, pages 1 through 3, and on page 1 of Attachment 11. 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 11, page 2, illustrate the rate impact created by this shift in cost recovery.

H. Impacts of Telemetry

The Telemetry project is complete and no additional customers have requested transfer from interruptible to firm service.

V. CONCLUSION

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

2013. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: August 1, 2013

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern
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Attorney for Minnesota Energy Resources Corporation

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2013
NNG

Design Day Requirement		245,878
Total Peak Day Entitlement		253,485
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 31)	206,230
Firm Annual Throughput - Minnesota		21,397,632
No. of Firm Customers		178,578
Department Load Factor Calculation		28.43%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2013
NNG

Pipeline Group	Nov12-Mar 13 Avg. Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	Nov12-Mar 13 Avg. Customer Growth	Total *
PEAK										
NNG	178,578	178,578	100	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
Total	178,578	178,578								245,783
OFF PEAK										
NNG	178,578	178,578	55	41,361	2,341	182,893	27,735	155,158	0.60%	156,089
Total	178,578	178,578								156,089

* Adjusted for customer growth

Footnote 1: Regression Total is based on total through-put data.
Footnote 2: Regression Adjustment substracts out Interruptible, Transportation and Joint Interruptible volumes and adds adjustment to achieve 97.5% confidence level confidence level that actual demand under design conditions will not exceed estimate.
Footnote 3: Total equals Regression Total minus Regression Adjustment.

*55 is the 30 yr unadjusted heating degree days from NOAA, not adjusted for windspeed.

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND PER CUSTOMER - GS

NOVEMBER 1, 2013

		NNG	
Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
13/14	178,578	245,878	1.38
12/13	176,937	225,883	1.28
11/12	175,241	235,055	1.34
10/11	176,027	218,213	1.24
09/10	175,228	228,040	1.30
08/09	173,962	247,188	1.42
07/08	172,116	223,754	1.30
06/07	165,053	222,119	1.35

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2014

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	6,026,020	15,356,677	21,382,697
SVI	429,569	720,094	1,149,663
SVJ	6,730	8,205	14,935
LVI	291,319	477,383	768,702
LVJ	0	0	0
SLV	0	0	0
Total	6,753,638	16,562,359	23,315,997

Source: Calendar data from MERCFCST201304 NEW PGA WIP (Matt's).xlsx

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2013

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
TF-12 Base & Variable	75,316	763	76,079
TF5	32,278	(763)	31,515
TFX - 12	32,297	0	32,297
TFX - 5	90,184	0	90,184
TFX- (Apr) Offpeak*	2,000	0	2,000
TFX- (Oct) Offpeak*	2,000	0	2,000
Bison	50,000	0	50,000
NBPL	50,000	0	50,000
Northwest Gas (Windom)	2,500	0	2,500
Northwestern Energy (Ortonville)	910	0	910
NNG Zone Delivery Call Option	0	20,000	20,000
Heating Season Total	**233,485**	**20,000**	**253,485**
Non-Heating Season Total	113,023	763	113,786
Heating Season Forecasted Design Day-Adjusted	225,883	19,995	245,878
Non-Heating Season Forecasted Design Day	141,002	15,087	156,089
Heating Season Capacity Surplus/Shortage	7,602	5	7,607
Non-Heating Season Capacity Surplus/Shortage	(27,979)	(14,324)	(42,303)

*Not included in Heating Season Total entitlement

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2013
NNG

All costs in $/Dth	Last Base Cost of Gas G007, G011/ MR10-978*	Last Demand Change G011-12-1193 Nov. 12	Last Demand Change G011-10-977 Jan. 13	Most Recent PGA Aug. 2013	Current Proposal Effective Nov.1,2013	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service Residential: Avg. Annual Use:		**71**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	($0.9356)	$0.3529	-2.11%	($0.0820)
Demand Cost	$1.6894	$1.8818	$1.6711	$1.6968	$1.7561	$0.0667	$0.0850	3.49%	$0.0593
Commodity Margin	$1.9754	$1.9417	$1.9754	$1.9754	$1.9754	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$8.4109	$7.2886	$7.1041	$7.5647	$7.5420	($0.8689)	$0.4379	-0.30%	($0.0227)
Avg Annual Cost	$595.49	$516.03	$502.97	$535.58	$533.97	($61.52)	$31.00	-0.30%	($1.61)
Effect of proposed commodity change on average annual bills:									($5.81)
Effect of proposed demand change on average annual bills:									$4.20
2) Small Vol. Interruptible: Avg. Annual Use:		**4,034**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	($0.9356)	$0.3529	-2.11%	($0.0820)
Demand Cost	$0.0000								
Commodity Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.8108	$4.7432	$4.5223	$4.9572	$4.8752	($0.9356)	$0.3529	-1.65%	($0.0820)
Avg Annual Cost	$23,440.77	$19,134.07	$18,242.96	$19,997.34	$19,666.56	($3,774.21)	$1,423.60	-1.65%	($330.79)
Effect of proposed commodity change on average annual bills:									($330.79)
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**20,096**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	($0.9356)	$0.3529	-2.11%	($0.0820)
Demand Cost									
Commodity Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.1029	$3.8205	$3.8144	$4.2493	$4.1673	($0.9356)	$0.3529	-1.93%	($0.0820)
Avg Annual Cost	$102,547.88	$76,776.77	$76,654.18	$85,393.93	$83,746.06	($18,801.82)	$7,091.88	-1.93%	($1,647.87)
Effect of proposed commodity change on average annual bills:									($1,647.87)
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,800**		**Dth**					
		25		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	($0.9356)	$0.3529	-2.11%	($0.0820)
Demand Cost	$19.5620	$19.3628	$19.3628	$19.4140	$18.7211	($0.8409)	($0.6417)	-3.57%	($0.6929)
Commodity Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.3000	$1.9695	$2.3000	$2.3000	$2.3000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.8108	$4.7432	$4.5223	$4.9572	$4.8752	($0.9356)	$0.3529	-1.65%	($0.0820)
Total Demand Cost	$21.8620	$21.3323	$21.6628	$21.7140	$21.0211	($0.8409)	($0.6417)	-3.19%	($0.6929)
Avg Annual Cost	$28,438.39	$23,300.67	$22,248.61	$24,337.41	$23,926.49	($4,511.90)	$1,677.88	-1.69%	($410.92)
Effect of proposed commodity change on average annual bills:									($393.60)
Effect of proposed demand change on average annual bills:									($17.32)
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Dth**					
		75		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	($0.9356)	$0.3529	-2.11%	($0.0820)
Demand Cost	$19.5620	$19.3628	$19.3628	$19.4140	$18.7211	($0.8409)	($0.6417)	-3.57%	($0.6929)
Commodity Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.3000	$1.5319	$2.3000	$2.3000	$2.3000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.1029	$3.8205	$3.8144	$4.2493	$4.1673	($0.9356)	$0.3529	-1.93%	($0.0820)
Total Demand Cost	$21.8620	$20.8947	$21.6628	$21.7140	$21.0211	($0.8409)	($0.6417)	-3.19%	($0.6929)
Avg Annual Cost	$77,371.79	$58,267.14	$58,234.22	$64,692.41	$63,423.48	($4,511.90)	$5,189.26	-1.96%	($1,268.93)
Effect of proposed commodity change on average annual bills:									($1,216.96)
Effect of proposed demand change on average annual bills:									($51.97)

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-12-756
*As approved in Docket No. G007,011/MR-10-978; with implementation consolidated PGA rates on 7/1/13 in Docket No. G007,011/MR-10-977

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2013

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE

01-Nov-13

		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	112495	$5.6830	$10.0850	$7.5171	$0.0000	$7.5171
TF-12B Discount	112495	$5.6830	$7.6000	$6.4818	$0.0000	$6.4818
TF-12V	112495	$5.6830	$13.8660	$9.0926	$0.0000	$9.0926
TF-5	112495		$15.1530	$15.1530	$0.0000	$15.1530
TFX	112486	$5.6830	$15.1530	$9.6288	$0.0000	$9.6288
TFX-5	112486		$15.1530	$15.1530	$0.0000	$15.1530
TFX-5 Discount	112486		$7.6000	$7.6000	$0.0000	$7.6000
TFX - Discount	111866	$7.6025		$7.6025	$0.0000	$7.6025
TFX - Discount	111866	$15.1392		$15.1392	$0.0000	$15.1392
TFX - Discount	111866	$5.4720	$5.4720	$5.4720	$0.0000	$5.4720
TFX - Discount	111866	$4.8640	$4.8640	$4.8640	$0.0000	$4.8640
Gas Commodity Cost						$3.8105

V. ANNUAL SALES -- As approved in Docket No. G007,011/MR-10-977

Total MERC NNG Annual Sales 248,613,760 Therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE:

01-Nov-13

		Contract #(s)	Monthly Entitlement (Dth)	Months	Rate $/Dth		Contract Costs	Rate/Therm
A. GS	TF12B (Max Rate)	112495	41,844	12	$7.5171	=	$3,774,555	$0.01693
	TF12V (Max Rate)	112495	29,035	12	$9.0926	=	$3,168,044	$0.01421
	TF5 (Max Rate)	112495	31,515	5	$15.1530	=	$2,387,734	$0.01071
	TF12B (Discount-Winter)	112495	5,200	12	$6.4818	=	$404,464	$0.00181
	TFX5 (Discount)	112561	6,000	5	$4.5600	=	$136,800	$0.00061
	TFX12 (Max Rate)	112486	10,822	12	$9.6288	=	$1,250,434	$0.00561
	TFX Apr (Max Rate)	112486	2,000	1	$5.6830	=	$11,366	$0.00005
	TFX Oct (Max Rate)	112486	2,000	1	$5.6830	=	$11,366	$0.00005
	TFX5 (Max Rate)	112486	57,371	5	$15.1530	=	$4,346,714	$0.01950
	TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00031
	TFX12 (Discount)	111866	1,283	12	$4.8640	=	$74,886	$0.00034
	TFX12 (Discount)	111866	8,271	12	$5.4720	=	$543,107	$0.00244
	TFX12 (Discount)	111866	11,921	12	$7.6025	=	$1,087,553	$0.00488
	TFX5 (Discount)	111866	379	5	$4.8640	=	$9,217	$0.00004
	TFX5 (Discount)	111866	2,445	5	$5.4720	=	$66,895	$0.00030
	TFX5 (Discount)	111866	22,189	5	$15.1392	=	$1,679,619	$0.00753
	SMS	112521	22,680	12	$2.1800	=	$593,309	$0.00266
	Bison	FT0003	50,000	12	$17.4896	=	$10,493,750	$0.04707
	NBPL	T8673F	50,000	12	$6.9958	=	$4,197,500	$0.01883
	Windom		2,500	12	$0.0000	=	$0	$0.00000
	Ortonville		910	12	$8.0000	=	$87,360	$0.00039
	NNG Zone GDD Call Option		20,000	3	$0.9000	=	$54,000	$0.00024
FDD:	Storage Reservation	118657	75,437	12	$1.7140	=	$1,551,588	$0.00696
	Storage Cycle Volume	118657	869,864	5	$0.3567	=	$1,551,402	$0.00696
	Storage Reservation	118657	5,550	12	$3.3157	=	$220,826	$0.00099
	Storage Cycle Volume	118657	64,000	5	$0.6901	=	$220,832	$0.00099
	Storage Reservation	125344	13,008	12	$1.7140	=	$267,549	$0.00120
	Storage Cycle Volume	125344	150,000	5	$0.3567	=	$267,525	$0.00120
	Storage Reservation	125345	3,468	12	$1.7140	=	$71,330	$0.00032
	Storage Cycle Volume	125345	40,000	5	$0.3567	=	$71,340	$0.00032
	Total Demand Cost						$38,669,465	$0.17281
	Rate Case volume as approved in Docket No. G007,011/MR-10-977 in therms						222,946,650	
	NNG-GS Demand Current Cost of Gas/therm							**$0.17345**
	NNG-GS Commodity Current Cost of Gas/therm+							**$0.38410**
	Total NNG-GS Current Cost of Gas/therm							**$0.55755**

B. NNG-GS, NNG-SVI, NNG-LVI, NNG-SJ, NNG-LJ, SLV-Commodity

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	24,861,376	x	$3.8105	$94,734,273.25	248,613,760	$0.38105
Call Option Premium				$ 758,741	248,613,760	$0.00305
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$ 95,493,014	248,613,760	$0.38410

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2013

NNG

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	41,844	112495	12	$7.5171	=	$3,774,555	$0.18742
TF12V (Max Rate)	29,035	112495	12	$9.0926	=	$3,168,044	$0.15731
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.11856
TF12B (Discount-Winter)	5,200	112495	12	$6.4818	=	$404,464	$0.02008
TFX5 (Discount)	6,000	112561	5	$4.5600	=	$136,800	$0.00679
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06209
TFX Apr (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00056
TFX Oct (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00056
TFX5 (Max Rate)	57,371	112486	5	$15.1530	=	$4,346,714	$0.21583
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00340
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00372
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02697
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05400
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00046
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00332
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08340
SMS	22,680	112521	12	$2.1800	=	$593,309	$0.02946
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.52106
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00434
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00268
Storage Reservation	75,437	118657	12	$1.7140	=	$1,551,588	$0.07704
Storage Cycle Volume	869,864	118657	5	$0.3567	=	$1,551,402	$0.07703
Storage Reservation	5,550	118657	12	$3.3157	=	$220,826	$0.01096
Storage Cycle Volume	64,000	118657	5	$0.6901	=	$220,832	$0.01097
Storage Reservation	13,008	125344	12	$1.7140	=	$267,549	$0.01328
Storage Cycle Volume	150,000	125344	5	$0.3567	=	$267,525	$0.01328
Storage Reservation	3,468	125345	12	$1.7140	=	$71,330	$0.00354
Storage Cycle Volume	40,000	125345	5	$0.3567	=	$71,340	$0.00354
				TOTAL		$38,669,465	
				Annualized Entitlement		20,139,270	
				Demand Component		$1.92010	$1.71168

MINNESOTA ENERGY RESOURCES - NNG

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

NOVEMBER 1, 2013

NNG

All costs in $/Dth	Last Base Cost of Gas G007,G011/ MR10-978*	Demand Change G011-12-1193 Nov. 12	Last Demand Change G011-10-977 Jan. 13	Most Recent PGA Aug. 2013	Current Proposal Effective Nov.1,2013	Result of Proposed Change			
						Change from Last Rate Case**	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service Residential: Avg. Annual		**71**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	($0.7352)	$0.5533	3.04%	$0.1184
Demand Cost	$1.6894	$1.8818	$1.6711	$1.6968	$1.5387	($0.1507)	($0.1324)	-9.32%	($0.1581)
Commodity Margin	$1.9754	$1.9417	$1.9754	$1.9754	$1.9754	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$8.4109	$7.2886	$7.1041	$7.5647	$7.5250	($0.8859)	$0.4209	-0.52%	($0.0397)
Avg Annual Cost	$595.49	$516.03	$502.97	$535.58	$532.77	($62.72)	$29.80	-0.52%	($2.81)
Effect of proposed commodity change on average annual bills:									$8.38
Effect of proposed demand change on average annual bills:									($11.19)
2) Small Vol. Interruptible: Avg. Annual Use:		**4,034**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	($0.7352)	$0.5533	3.04%	$0.1184
Demand Cost									
Commodity Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.8108	$4.7432	$4.5223	$4.9572	$5.0756	($0.7352)	$0.5533	2.39%	$0.1184
Avg Annual Cost	$23,440.77	$19,134.07	$18,242.96	$19,997.34	$20,474.79	($2,965.97)	$2,231.84	2.39%	$477.45
Effect of proposed commodity change on average annual bills:									$477.45
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**20,096**		**Dth**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	($0.7352)	$0.5533	3.04%	$0.1184
Demand Cost									
Commodity Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.1029	$3.8205	$3.8144	$4.2493	$4.3677	($0.7352)	$0.5533	2.79%	$0.1184
Avg Annual Cost	$102,547.88	$76,776.77	$76,654.18	$85,393.93	$87,772.42	($14,775.46)	$11,118.24	2.79%	$2,378.49
Effect of proposed commodity change on average annual bills:									$2,378.49
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,800**		**Dth**					
		25		**DTh**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	($0.7352)	$0.5533	3.04%	$0.1184
Demand Cost	$19.5620	$19.3628	$19.3628	$19.4140	$17.3631	($2.1989)	($1.9997)	-10.56%	($2.0509)
Commodity Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.3000	$1.9695	$2.3000	$2.3000	$2.3000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.8108	$4.7432	$4.5223	$4.9572	$5.0756	($0.7352)	$0.5533	2.39%	$0.1184
Total Demand Cost	$21.8620	$21.3323	$21.6628	$21.7140	$19.6631	($2.1989)	($1.9997)	-9.45%	($2.0509)
Avg Annual Cost	$28,438.39	$23,300.67	$22,248.61	$24,337.41	$24,854.25	($3,584.14)	$2,605.64	2.12%	$516.84
Effect of proposed commodity change on average annual bills:									$568.11
Effect of proposed demand change on average annual bills:									($51.27)
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Dth**					
		75		**DTh**					
Commodity Cost	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	($0.7352)	$0.5533	3.04%	$0.1184
Demand Cost	$19.5620	$19.3628	$19.3628	$19.4140	$17.3631	($2.1989)	($1.9997)	-10.56%	($2.0509)
Commodity Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	$0.0000	$0.0000	0.00%	$0.0000
Demand Margin	$2.3000	$1.5319	$2.3000	$2.3000	$2.3000	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$5.1029	$3.8205	$3.8144	$4.2493	$4.3677	($0.7352)	$0.5533	2.79%	$0.1184
Total Demand Cost	$21.8620	$20.8947	$21.6628	$21.7140	$19.6631	($2.1989)	($1.9997)	-9.45%	($2.0509)
Avg Annual Cost	$77,371.79	$58,267.14	$58,234.22	$64,692.41	$66,295.12	($3,584.14)	$8,060.90	2.48%	$1,602.71
Effect of proposed commodity change on average annual bills:									$1,756.53
Effect of proposed demand change on average annual bills:									($153.82)

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

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

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

NOVEMBER 1, 2013

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	01-Nov-10 Total
TF-12B	112495	$5.6830	$10.0850	$7.5172	$0.0000	$7.5172
TF-12B Discount	112495	$5.6830	$7.6000	$6.4818	$0.0000	$6.4818
TF-12V	112495	$5.6830	$13.8660	$9.0926	$0.0000	$9.0926
TF-5	112495	$0.0000	$15.1530	$6.3138	$0.0000	$6.3138
TFX	112486	$5.6830	$15.1530	$9.6288	$0.0000	$9.6288
TFX-5	112486	$0.0000	$15.1530	$6.3138	$0.0000	$6.3138
TFX-5 Discount	112486	$0.0000	$7.6000	$3.1667	$0.0000	$3.1667
TFX - Discount	111866	$7.6025	$0.0000	$4.4348	$0.0000	$4.4348
TFX - Discount	111866	$15.1392	$0.0000	$8.8312	$0.0000	$8.8312
TFX - Discount	111866	$5.4720	$5.4720	$5.4720	$0.0000	$5.4720
TFX - Discount	111866	$4.8640	$4.8640	$4.8640	$0.0000	$4.8640
Gas Cost						$3.8105

V. ANNUAL SALES -- RATE CASE 2008 TOTAL 248,613,760

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-10

		Contract #(s)		Months				Rate/CCF
A. GS	TF12B (Max Rate)	112495	41,844	12	$7.5171	=	$3,774,555	$0.01693
	TF12V (Max Rate)	112495	29,035	12	$9.0926	=	$3,168,044	$0.01421
	TF5 (Max Rate)	112495	31,515	5	$15.1530	=	$2,387,734	$0.01071
	TF12B (Discount-Winter)	112495	5,200	12	$6.4818	=	$404,464	$0.00181
	TFX5 (Discount)	112561	6,000	5	$4.5600	=	$136,800	$0.00061
	TFX12 (Max Rate)	112486	10,822	12	$9.6288	=	$1,250,434	$0.00561
	TFX Apr (Max Rate)	112486	2,000	1	$5.6830	=	$11,366	$0.00005
	TFX Oct (Max Rate)	112486	2,000	1	$5.6830	=	$11,366	$0.00005
	TFX5 (Max Rate)	112486	57,371	5	$15.1530	=	$4,346,714	$0.01950
	TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00031
	TFX12 (Discount)	111866	1,283	12	$4.8640	=	$74,886	$0.00034
	TFX12 (Discount)	111866	8,271	12	$5.4720	=	$543,107	$0.00244
	TFX12 (Discount)	111866	11,921	12	$7.6025	=	$1,087,553	$0.00488
	TFX5 (Discount)	111866	379	5	$4.8640	=	$9,217	$0.00004
	TFX5 (Discount)	111866	2,445	5	$5.4720	=	$66,895	$0.00030
	TFX5 (Discount)	111866	22,189	5	$15.1392	=	$1,679,619	$0.00753
	SMS	112521	22,680	12	$2.1800	=	$593,309	$0.00266
	Bison	FT0003	50,000	12	$17.4896	=	$10,493,750	$0.04707
	NBPL	T8673F	50,000	12	$6.9958	=	$4,197,500	$0.01883
	Windom		2,500	12	$0.0000	=	$0	$0.00000
	Ortonville		910	12	$8.0000	=	$87,360	$0.00039
	NNG Zone GDD Call Option		20,000	3	$0.9000	=	$54,000	$0.00024
	Total Demand Cost						$34,447,073	**$0.15387**
	Rate Case 2008 volume in Ccf						222,946,650	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.15451**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.40109**
	Total GS-1 Current Cost of Gas/Ccf							**$0.55559**

B. GS-1, SVI, LVI, SJ-1, LJ-1, SLV-Commodity

			Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Contract Costs	Rate ($/therm)
FDD:	FDD - Reservation	118657	75,437	12	$1.7140	=	$1,551,588	$0.00624
	FDD - Storage Cycle	118657	869,864	5	$0.3567	=	$1,551,402	$0.00624
	FDD - Reservation	118657	5,550	12	$3.3157	=	$220,826	$0.00089
	FDD - Storage Cycle	118657	64,000	5	$0.6901	=	$220,832	$0.00089
	FDD - Reservation	125344	13,008	12	$1.7140	=	$267,549	$0.00108
	FDD - Storage Cycle	125344	150,000	5	$0.3567	=	$267,525	$0.00108
	FDD - Reservation	125345	3,468	12	$1.7140	=	$71,330	$0.00029
	FDD - Storage Cycle	125345	40,000	5	$0.3567	=	$71,340	$0.00029
	Firm Deferred Delivery Storage Contracts						$4,222,392	$0.01641

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	24,861,376	x	$3.8105	$94,734,273	248,613,760	$0.38105
Call Option Premium				$758,741	248,613,760	$0.00305
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$99,715,405	248,613,760	**$0.40109**
CURRENT FIRM TRANSPORTATION COST OF GAS (CCF)						$0.75172

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C) $1.73631 $1.73631

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

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

NOVEMBER 1, 2013

NNG

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate)	41,844	112495	12	$7.5171	=	$3,774,555	$0.19026
TF12V (Max Rate)	29,035	112495	12	$9.0926	=	$3,168,044	$0.15969
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.12035
TF12B (Discount-Winter)	5,200	112495	12	$6.4818	=	$404,464	$0.02039
TFX5 (Discount)	6,000	112561	5	$4.5600	=	$136,800	$0.00690
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06303
TFX Apr (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00057
TFX Oct (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00057
TFX5 (Max Rate)	57,371	112486	5	$15.1530	=	$4,346,714	$0.21910
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00345
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00377
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02738
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05482
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00046
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00337
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08466
SMS	22,680	112521	12	$2.1800	=	$593,309	$0.02991
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.52894
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	$0.21158
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00440
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00272
Storage Reservation	75,437	118657	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	869,864	118657	0	$0.3567	=	$0	$0.00000
Storage Reservation	5,550	118657	0	$3.3157	=	$0	$0.00000
Storage Cycle Volume	64,000	118657	0	$0.6901	=	$0	$0.00000
Storage Reservation	13,008	125344	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	150,000	125344	0	$0.3567	=	$0	$0.00000
Storage Reservation	3,468	125345	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	40,000	125345	0	$0.3567	=	$0	$0.00000
				TOTAL		$34,447,073	
				Annualized Entitlement		19,839,270	
				Demand Component		$1.73631	$1.73631

Attachment 5

MINNESOTA ENERGY RESOURCES - NNG

NNG Entitlement Allocation

Heating Season 2013-2014

		Total Entitlement Levels	Total
1	Design Day	245,783	245,783
2	Customer Requirements moving to Transport	-	-
3	Adjusted Design Day	245,878	245,878
		100.00%	100.00%
5	Total Design Day Capacity	232,575	232,575
6	Less: Windom	(2,500)	(2,500)
7	Less: Northwestern Energy	(910)	(910)
8	Less: LS Power	0	-
9	Less: Chisago Delivery to Viking	0	-
10	Less: Contract Demand Units	(95)	(95)
		229,070	229,070
	Direct Assigned Entitlement		
11	TF12B (112495)	47,044	47,044
12	TF12V (112495)	29,035	29,035
13	TF5 (112495)	31,515	31,515
14	TFX12 (112486)	10,822	10,822
15	TFX April Only (112486)	2,000	2,000
16	TFX October Only (112486)	2,000	2,000
17	TFX5 (112486)	59,171	59,171
18	TFX12 (111866)	21,475	21,475
19	TFX5 (111866)	25,013	25,013
20	TFX5 (112561)	6,000	6,000
21	Bison (FT 0003) *	50,000	50,000
22	NBPL (T6873F) *	50,000	50,000
23	Total Winter Allocated Entitlement	230,075	230,075
24	Northwest Gas (Windom)	2,500	2,500
25	Northwestern Energy (Ortonville)	910	910
26	NNG Zone Delivery Call Option	20,000	20,000
27	LS Power	0	-
28	Total Design Day Capacity	253,485	253,485
29	Contract Demand		
30	Total Design Day Capacity	253,485	253,485
			100.00%
31	Storage		
32	Storage MSQ - 118657	4,669,321	4,669,321
33	Storage MSQ - 123780	750,000	750,000
34	Storage MSQ - 123781	200,000	200,000
35	SMS	22,680	22,680
36	Total Entitlement	253,485	253,485
37	Design Day	245,878	245,878
38	Reserve Margin	7,607	7,607
		3.09%	3.09%

***** 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 - NNG

CALCULATION OF DESIGN DAY REQUIREMENTS

2013-2014

State	1/20 Design DDD	12/13 Customer Counts*	Regression Factors Intercept	Slope	Regression Total	Adjustment Total *	1/20 Requirements Regression Load	Nov13-Mar14 Customer Growth	Total
MERC - Peak Day									
NNG	100	178,578	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
TOTAL	**100**	**178,578**	**41,361**	**2,341**	**287,358**	**43,041**	**244,317**		**245,783**
MERC - Non-Peak Day									
NNG	55	178,578	41,361	2,341	182,893	27,735	155,158	0.60%	156,089
TOTAL	**55**	**178,578**	**41,361**	**2,341**	**182,893**	**27,735**	**155,158**		**156,089**

* Adjustment to remove interruptible and transportation volumes and add adjustment to achieve 97.5% confidence level that actual demand under design conditions will not exceed estimate.

Attachment 7

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2014-2013 VS. 2013-2012

	2013-2014 Proposed		2012-2013		Difference	
	NNG	NNG	NNG	NNG		
	Winter	Total	Winter	Total	Winter	Total
TF12(base)	47,044	47,044	46,281	46,281	763	763
TF12(variable)	29,035	29,035	29,035	29,035	-	-
TF12	76,079	76,079	75,316	75,316	763	763
Peak Capacity	-	-	-	-	-	-
TF5	31,515	31,515	32,278	32,278	(763)	(763)
TF Total	107,594	107,594	107,594	107,594	-	-
TFX12	32,297	32,297	32,297	32,297	-	-
TFX5	90,184	90,184	90,184	90,184	-	-
TFX Total	122,481	122,481	122,481	122,481	-	-
NNG Total	230,075	230,075	230,075	230,075	-	-
Bison	50,000	50,000	50,000	50,000	-	-
NBPL	50,000	50,000	50,000	50,000	-	-
Windom	2,500	2,500	2,500	2,500	-	-
Ortonville	910	910	910	910	-	-
NNG Zone GDD Call Option	20,000	20,000	-	-	20,000	20,000
					-	
Total	253,485	253,485	233,485	233,485	20,000	20,000

	NNG-Total EF
Design Day	245,878
Capacity	253,485
Reserve Margin	7,607
	3.09%

Attachment 8

MINNESOTA ENERGY RESOURCES - NNG

Financial Options

Heating Season 2013-2014

Units - Gas Daily Peaker Packages (Physical)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
			TBD	20,000	TBD	20,000	TBD	20,000			60,000	1,800,000

Premium - Gas Daily Peaker (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
			$ 0.0300	$18,600	$ 0.0300	$18,600	$ 0.0300	$18,600			$ 0	$ 55,800

Units - Futures (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1	05/17/13	1,889	05/03/13	-	05/23/13	1,720	05/07/13	204	05/29/13	3,592	7,406	227,078
2	06/19/13	1,889	05/03/13	-	06/24/13	215	05/07/13	612	06/27/13	3,592	6,309	191,840
3	07/19/13	1,889	06/04/13	-	06/24/13	1,505	06/11/13	408	TBD	3,849	7,651	234,080
4	TBD	1,889	07/02/13	-	07/24/13	1,720	06/11/13	408	TBD	3,849	7,866	240,747
5	TBD	1,889	TBD	-	TBD	1,505	07/09/13	1,020	TBD	3,849	8,264	251,223
6	TBD	1,889	TBD	-	TBD	1,505	TBD	1,020	TBD	3,849	8,264	251,223
7			TBD	-	TBD	1,505	TBD	1,020			2,526	75,238
8							TBD	1,020			1,020	28,571
9											-	-
10											-	-
Total		11,333		0		9,677		5,714		22,581	49,306	1,500,000
		340,000		0		300,000		160,000		700,000		1,500,000
		480,000		100,000		450,000		280,000		880,000		2,190,000

Units - Call Options (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1	05/09/13	3,446	05/30/13	5,151	05/14/13	6,546	05/21/13	6,747	05/02/13	4,727	26,617	801,450
2	06/13/13	3,711	06/26/13	5,151	06/18/13	6,808	06/20/13	6,747	06/06/13	4,727	27,144	817,519
3	07/11/13	3,711	07/26/13	5,151	07/16/13	6,808	07/22/13	6,747	07/03/13	4,727	27,144	817,519
4	TBD	3,711	TBD	5,408	TBD	6,808	TBD	6,747	TBD	4,990	27,664	833,644
5	TBD	3,711	TBD	5,408	TBD	6,808	TBD	6,747	TBD	5,253	27,927	841,786
6	TBD	3,711	TBD	5,666	TBD	6,546	TBD	7,334	TBD	5,253	28,510	858,082
7												
Total		22,000		31,935		40,323		41,071		29,677	165,007	4,970,000
		660,000		990,000		1,250,000		1,150,000		920,000		4,970,000
		830,000		1,240,000		1,540,000		1,400,000		1,130,000		6,140,000

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
1	$ 0.3100	$ 32,046	$ 0.2500	$39,919	$ 0.3520	$71,429	$ 0.3850	$72,738	$ 0.4000	$ 58,619	$ 0.3428	$ 274,751
2	$ 0.2450	$ 27,275	$ 0.2830	$45,189	$ 0.3230	$68,166	$ 0.3520	$66,503	$ 0.3230	$ 47,335	$ 0.3113	$ 254,467
3	$ 0.2150	$ 23,935	$ 0.1870	$29,860	$ 0.2960	$62,468	$ 0.3280	$61,969	$ 0.3500	$ 51,292	$ 0.2808	$ 229,523
4		$ -		$0		$0		$0		$ -	$ -	$ -
5		$ -		$0		$0		$0		$ -	$ -	$ -
6		$ -		$0		$0		$0		$ -	$ -	$ -
7												
Total	**$ 0.1261**	**$ 83,255**	**$ 0.1161**	**$ 114,968**	**$ 0.1616**	**$ 202,062**	**$ 0.1750**	**$ 201,209**	**$ 0.1709**	**$ 157,247**	**$ 0.1527**	**$ 758,741**
		$ 104,700		**$ 144,000**		**$ 248,940**		**$ 244,950**		**$ 193,140**		**$ 935,730**

Units - Collar Floor (put)

No Puts were purchased.

13/14 Winter Portfolio Plan - MERC NNG Hedging Plan

10,000 Contract Size **REVISED:**

		Nov-13		Dec-13		Jan-14		Feb-14		Mar-14		Total		Percent
	Purchase	Number	Contract	Number	Contract	Number	Contract	Number	Contract	Number	Contract	Number	Contract	of
System	Month	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Requirements
MN Requirements			2,197,940		3,325,111		4,167,658		3,833,379		3,042,634		16,566,721	16,566,721
NNG -MN			73,265		107,262		134,441		136,906		98,149		109,713	
70%			1,538,558		2,327,577		2,917,361		2,683,365		2,129,843		11,596,705	
40%			879,176		1,330,044		1,667,063		1,533,352		1,217,053		6,626,688	
			547,884		1,376,734		1,376,734		1,376,734		547,884		5,225,970	
			331,292		-46,690		290,329		156,618		669,169		1,400,718	
30%			659,382		997,533		1,250,297		1,150,014		912,790		4,970,016	
Contracts	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	May-13	5	50,000	0	0	5	50,000	2	20,000	11	110,000	23	230,000	
	Jun-13	5	50,000	0	0	5	50,000	2	20,000	11	110,000	23	230,000	
	Jul-13	6	60,000	0	0	5	50,000	3	30,000	12	120,000	26	260,000	
	Aug-13	6	60,000	0	0	5	50,000	3	30,000	12	120,000	26	260,000	
	Sep-13	6	60,000	0	0	5	50,000	3	30,000	12	120,000	26	260,000	
	Oct-13	6	60,000	0	0	5	50,000	3	30,000	12	120,000	26	260,000	
	Total	**34**	**340,000**	**0**	**0**	**30**	**300,000**	**16**	**160,000**	**70**	**700,000**	**150**	**1,500,000**	**9.05%**
Call Options	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	May-13	11	110,000	16	160,000	20	200,000	19	190,000	15	150,000	81	810,000	
	Jun-13	11	110,000	16	160,000	21	210,000	19	190,000	15	150,000	82	820,000	
	Jul-13	11	110,000	16	160,000	21	210,000	19	190,000	15	150,000	82	820,000	
	Aug-13	11	110,000	17	170,000	21	210,000	19	190,000	15	150,000	83	830,000	
	Sep-13	11	110,000	17	170,000	21	210,000	19	190,000	16	160,000	84	840,000	
	Oct-13	11	110,000	17	170,000	21	210,000	20	200,000	16	160,000	85	850,000	
	Total	**66**	**660,000**	**99**	**990,000**	**125**	**1,250,000**	**115**	**1,150,000**	**92**	**920,000**	**497**	**4,970,000**	**30.00%**
Collars	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.00%**
Index (back financial)	May-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-13	11,112	333,360	10,646	330,026	16,666	516,646	15,596	436,688	17,420	540,020	71,440	2,156,740	
	Sep-13	11,111	333,330	10,645	329,995	16,667	516,677	15,595	436,660	17,419	539,989	71,437	2,156,651	
	Oct-13	11,111	333,330	10,645	329,995	16,667	516,677	15,595	436,660	17,419	539,989	71,437	2,156,651	
	Total		**1,000,020**		**990,016**		**1,550,000**		**1,310,008**		**1,619,998**		**6,470,042**	**39.05%**
Physical Hedges			**0**		**0**		**0**		**0**		**0**		**0**	
Storage			547,884		1,376,734		1,376,734		1,376,734		547,884		5,225,970	**31.54%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			70.43%		71.18%		70.22%		70.09%		71.25%		70.60%	
Term Index		0	0	0	0	0	0	0	0	0	0		0	**0.00%**
		0	0	0	0	0	0	0	0	0	0		0	**0.00%**
Total NNG MN														
Fixed Price													1,500,000	**9.05%**
Call Options													4,970,000	**30.00%**
Costing Collar													0	**0.00%**
Storage													5,225,970	**31.54%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													4,870,751	**29.40%**
Total													16,566,721	**100.00%**

NOTE:

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN
NOVEMBER, 2013 THROUGH MARCH, 2014

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Daily Volumes Nov	Dec	Jan	Feb	Mar	Monthly Total
										-
No Physical Fixed Price Hedges										-
										-
	Total Actual Fixed/Option Physical				-	-	-	-	-	-

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Index - Back Financial Options		TBD	NNG Ventura	3,321	1,923	19,987	16,773	22,245	1,938,079
Index - Back Financial Options		TBD	NNG Welcome	8,932	8,932	8,932	8,932	8,932	1,348,732
Index - Back Financial Options		TBD	NNG Aberdeen	3,249	3,249	3,249	3,249	3,249	490,599
Index - Back Financial Options		TBD	NNG Beatrice	5,632	5,632	5,632	5,632	5,632	850,432
Index - Back Financial Options		TBD	NNG Marshall	12,200	12,200	12,200	12,200	12,200	1,842,200
	Total Actual Seasonal Index			**33,334**	**31,936**	**50,000**	**46,786**	**52,258**	**6,470,042**
GAS DAILY PACKAGES									
	TBD	TBD	MERC Zone EF	-	25,000	25,000	25,000	-	75,000

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 125344 Volume Injected	Contract # 125345 Volume Injected	Total Volume Injected
May - balance forward	302,570	0	0	302,570
June	584,713	144,780	38,610	768,103
July	974,342	154,240	41,129	1,169,711
August	946,071	151,960	40,522	1,138,553
Sept	915,553	147,059	39,216	1,101,828
Oct (est)	946,072	151,961	40,523	1,138,556
Total	**4,669,321**	**750,000**	**200,000**	**5,619,321**

MINNESOTA ENERGY RESOURCES - NNG

	M-09-Peoples Mn GS	M-10-Peoples Mn GS	M-11-Peoples Mn GS	**M-12-Peoples Mn GS**	**M-13-Peoples Mn GS**	Proposed Change
Design Day	203,360	194,598	211,182	**200,785**	**245,878**	45,093
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	31.50%	35.92%	33.31%	**38.29%**	**28.43%**	-9.86%
Total Design Day Capacity (includes non-recallable capacity	238,064	233,627	221,436	**208,007**	**253,485**	45,478
Less: Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
Less: Northwestern Energy	0	0	910	**910**	**910**	0
Less: LS Power	26,375	25,951	0	**0**	**0**	0
Less: TF12B	7,000	0	0	**0**	**0**	0
Less: TF5						
Less: TFX(5)						
Total Design Day Capacity	202,189	205,176	218,026	**204,597**	**250,075**	45,478
Factors for All Winter Capacity	100.00%	100.00%	100.00%	**100.00%**	**100.00%**	
Allocated Entitlements in PGA						
TF12B	35,221	34,875	42,396	**41,156**		-41,156
TF12V	24,583	32,290	25,298	**25,820**		-25,820
TF5	29,619	28,785	29,011	**28,704**		-28,704
TFX12	31,199	28,802	29,029	**28,721**		-28,721
TFX(5)	81,567	80,424	81,057	**80,197**		-80,197
TFX(5) (12-V)	0	0	0	**0**		0
TFX (October Only)	0	1,784	1,798	**1,779**		-1,779
TFX (April Only)	0	1,784	1,798	**1,779**		-1,779
NNG Zone Delivery Call Option	0	0	11,235	**0**		0
LS Power	26,375	25,951	0	**0**		0
Bison *	0	44,589	44,940	**44,463**		-44,463
NBPL *	0	44,589	44,940	**44,463**		-44,463
Peak Capacity	228,564	231,127	218,026	**205,508**	**0**	-205,508
Total Allocated Entitlements in PGA	228,564	323,873	311,502	297,082	0	-297,082

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

	M-09-Peoples Mn GS	M-10-Peoples Mn GS	M-11-Peoples Mn GS	**M-12-Peoples Mn GS**	**M-13-Peoples Mn GS**	Proposed Change
Direct Assigned Entitlements in PGA						
TF12B					**47,044**	**47,044**
TF12V					**29,035**	**29,035**
TF5					**31,515**	**31,515**
TFX12					**32,297**	**32,297**
TFX(5)					**90,184**	**90,184**
TFX(5) (12-V)						**0**
TFX (October Only)					**2,000**	**2,000**
TFX (April Only)					**2,000**	**2,000**
Windom	2,500	2,500	2,500	**2,500**	**2,500**	**0**
Northwestern Energy	0	0	910	**910**	**910**	**0**
NNG Zone Delivery Call Option					**20,000**	**20,000**
LS Power	0	0	0	**0**	**0**	**0**
Bison *					**50,000**	**50,000**
NBPL *					**50,000**	**50,000**
TFX (October Only)	2,000	0	0	**0**	**0**	**0**
TFX (April Only)	2,000	0	0	**0**	**0**	**0**
TFX(5)	0	0	0	0	**0**	**0**
TFX(7)	0	0	0	0	**0**	**0**
TFX(5)	0	0	0	0	**0**	**0**
Total Direct Assignments	6,500	2,500	3,410	**3,410**	**253,485**	**250,075**
Total Capacity before Peak Shaving	235,064	233,627	221,436	**208,918**	**253,485**	**44,567**
LP Peak Shaving	0	0	0			**0**
Total Design Day Capacity	231,064	233,627	221,436	**208,918**	**253,485**	**44,567**
Total Transp. (with TFX Offpeak less LSP)	204,689	207,676	221,436	**208,918**	**253,485**	**44,567**
Total Annual Transportation	93,503	98,467	100,133	**99,107**	**111,786**	**12,679**
Total Seasonal Transportation	137,561	135,160	110,068	**108,901**	**141,699**	**32,798**
Total Percent Seasonal	59.5%	57.9%	49.7%	**52.1%**	**55.9%**	**2.4%**
LS Power as % of Total DD Capacity	11.4%	11.1%	0.0%	**0.0%**	**0.0%**	**0.0%**
Reserve Margin	13.62%	20.06%	4.86%	**4.05%**	**3.09%**	**-0.8%**
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	0	0	0	**0**	**0**	0
Total Design Day Capacity w/ contract demand	238,064	233,627	221,436	**208,007**	**253,485**	-12,191
Factors	31.50%	35.92%	33.31%	**38.29%**	**28.43%**	-2.61%
Other Entitlements not included in Peak Day Deliverability						
Field TF (TFF) (NMU direct assigned)	0	0	0	**0**	**0**	0
TFX Offpeak Old Oct. (60,000)	0	0	0	**0**	**0**	0
TFX Offpeak Old Oct. (35,000)	0	0	0	**0**	**0**	0
TFX Offpeak New Oct. (14,600)	0	0	0	**0**	**0**	0
TFX Offpeak New Apr. (39,600)	0	0	0	**0**	**0**	0
TFX Oct	2,000	1,784	1,798	**1,779**	**2,000**	221
TFX Apr	2,000	1,784	1,798	**1,779**	**2,000**	221
TFX Apr-Oct	0	0	0	**0**	**0**	0
TFX May-Sept	0	0	0	**0**	**0**	0
FDD Storage reservation	76,628	78,409	84,483	**86,671**	**97,463**	10,792
FDD Storage capacity	4,417,893	4,520,719	4,870,885	**4,997,056**	**5,619,321**	622,265
Nexen PSO	0	0	0	**0**	**0**	0
Tenaska PSO New	0	0	0	**0**	**0**	0
NGPL	0	0	0	**0**	**0**	0
SMS	20,577	20,226	20,385	**20,168**	**22,680**	2,512
SBA	0	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - NNG

Rate Impacts
NNG

1) General Service Residential: Avg. Annual Use: 71 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	-19.71%	10.21%	-2.11%	($0.0820)
Demand Rate	$1.6894	$1.8818	$1.6711	$1.6968	$1.7561	3.95%	5.09%	3.49%	$0.0593
Margin	$1.9754	$1.9417	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$8.4109	$7.2886	$7.1041	$7.5647	$7.5420	-10.33%	6.16%	-0.30%	($0.0227)
Avg. Annual Bill*	$595.49	$516.03	$502.97	$535.58	$533.97	-10.33%	6.16%	-0.30%	-$1.61
Effect of proposed commodity change on average annual bills:									-$5.81
Effect of proposed demand change on average annual bills:									$4.20

2) Small Volume Interruptible: Avg. Annual Use: 4,034 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	-19.71%	10.21%	-2.11%	($0.0820)
Demand Rate									$0.0000
Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$5.8108	$4.7432	$4.5223	$4.9572	$4.8752	-16.10%	7.80%	-1.65%	($0.0820)
Avg. Annual Bill*	$23,440.77	$19,134.07	$18,242.96	$19,997.34	$19,666.56	-16.10%	7.80%	-1.65%	-$330.79
Effect of proposed commodity change on average annual bills:									-$330.79
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 20,096 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	-19.71%	10.21%	-2.11%	($0.0820)
Demand Rate									$0.0000
Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$5.1029	$3.8205	$3.8144	$4.2493	$4.1673	-18.33%	9.25%	-1.93%	($0.0820)
Avg. Annual Bill*	$102,547.88	$76,776.77	$76,654.18	$85,393.93	$83,746.06	-18.33%	9.25%	-1.93%	-$1,647.87
Effect of proposed commodity change on average annual bills:									-$1,647.87
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 4,800 Dth
Avg. Annual CD Volumes: 25 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	-19.71%	10.21%	-2.11%	($0.0820)
Demand Rate	$19.5620	$19.3628	$19.3628	$19.4140	$18.7211	-4.30%	-3.31%	-3.57%	($0.6929)
Comm. Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.3000	$1.9695	$2.3000	$2.3000	$2.3000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$5.8108	$4.7432	$4.5223	$4.9572	$4.8752	-16.10%	7.80%	-1.65%	($0.0820)
Total Demand Cost	$21.8620	$21.3323	$21.6628	$21.7140	$21.0211	-3.85%	-2.96%	-3.19%	($0.6929)
Avg. Annual Bill*	$28,438.39	$23,300.67	$22,248.61	$24,337.41	$23,926.49	-15.87%	7.54%	-1.69%	-$410.92
Effect of proposed commodity change on average annual bills:									-$393.60
Effect of proposed demand change on average annual bills:									-$17.32

5) Large Volume Firm: Avg. Annual Use: 14,841 Dth
Avg. Annual CD Units: 75 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$3.8105	-19.71%	10.21%	-2.11%	($0.0820)
Demand Rate	$19.5620	$19.3628	$19.3628	$19.4140	$18.7211	-4.30%	-3.31%	-3.57%	($0.6929)
Comm. Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$2.3000	$1.5319	$2.3000	$2.3000	$2.3000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$5.1029	$3.8205	$3.8144	$4.2493	$4.1673	-18.33%	9.25%	-1.93%	($0.0820)
Total Demand Cost	$21.8620	$20.8947	$21.6628	$21.7140	$21.0211	-3.85%	-2.96%	-3.19%	($0.6929)
Avg. Annual Bill*	$77,371.79	$58,267.14	$58,234.22	$64,692.41	$63,423.48	-18.03%	8.91%	-1.96%	-$1,268.93
Effect of proposed commodity change on average annual bills:									-$1,216.96
Effect of proposed demand change on average annual bills:									-$51.97

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

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	($0.0820)	-2.11%	-8.20%	$0.0593	3.49%	(0.0227)		-0.30%
Sm Vol Inter. Service	($0.0820)	-2.11%	-8.20%	$0.0000	0.00%	(0.0820)		-1.65%
Lrg Vol Inter. Service	($0.0820)	-2.11%	-8.20%	$0.0000	0.00%	(0.0820)		-1.93%
Sm Vol Joint Service	($0.0820)	-2.11%	-8.20%	($0.6929)	-3.57%	(0.0820)	***	-1.65%
Lrg Vol Joint Service	($0.0820)	-2.11%	-8.20%	($0.6929)	-3.57%	(0.0820)	***	-1.93%

*** Joint total change includes only commodity change since not all joint customers purchase CD units.

MINNESOTA ENERGY RESOURCES - NNG

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

1) General Service Residential: Avg. Annual Use: 71 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	-15.49%	16.00%	3.04%	$0.1184
Demand Rate	$1.6894	$1.8818	$1.6711	$1.6968	$1.5387	-8.92%	-7.92%	-9.32%	($0.1581)
Margin	$1.9754	$1.9417	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$8.4109	$7.2886	$7.1041	$7.5647	$7.5250	-10.53%	5.92%	-0.52%	($0.0397)
Avg. Annual Bill*	$595.49	$516.03	$502.97	$535.58	$532.77	-10.53%	5.92%	-0.52%	($2.81)
Effect of proposed commodity change on average annual bills:									$8.38
Effect of proposed demand change on average annual bills:									($11.19)

2) Small Volume Interruptible: Avg. Annual Use: 4,034 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8925	$4.0109	-15.49%	16.00%	3.04%	$0.1184
Demand Rate									
Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$5.8108	$4.7432	$4.5223	$4.9572	$5.0756	-12.65%	12.23%	2.39%	$0.1184
Avg. Annual Bill*	$23,440.77	$19,134.07	$18,242.96	$19,997.34	$20,474.79	-12.65%	12.23%	2.39%	$477.45
Effect of proposed commodity change on average annual bills:									$477.45
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 20,096 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8105	$4.0047	-15.62%	15.82%	5.10%	$0.1942
Demand Rate									
Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$5.1029	$3.8205	$3.8144	$4.1673	$4.3615	-14.53%	14.34%	4.66%	$0.1942
Avg. Annual Bill*	$102,547.88	$76,776.77	$76,654.18	$83,746.06	$87,647.70	-14.53%	14.34%	4.66%	$3,901.64
Effect of proposed commodity change on average annual bills:									$3,901.64
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 4,800 Dth
Avg. Annual CD Volumes: 25 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8105	$4.0047	-15.62%	15.82%	5.10%	$0.1942
Demand Rate	$19.5620	$19.3628	$19.3628	$19.4140	$17.3631	-11.24%	-10.33%	-10.56%	($2.0509)
Comm. Margin	$1.0647	$1.2781	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.3000	$1.9695	$2.3000	$2.3000	$2.3000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$5.8108	$4.7432	$4.5223	$4.8752	$5.0694	-12.76%	12.10%	3.98%	$0.1942
Total Demand Cost	$21.8620	$21.3323	$21.6628	$21.7140	$19.6631	-10.06%	-9.23%	-9.45%	($2.0509)
Avg. Annual Bill*	$28,438.39	$23,300.67	$22,248.61	$23,943.81	$24,824.46	-12.71%	11.58%	3.68%	$880.65
Effect of proposed commodity change on average annual bills:									$931.92
Effect of proposed demand change on average annual bills:									($51.27)

5) Large Volume Firm: Avg. Annual Use: 14,841 Dth
Avg. Annual CD Units: 75 Dth

Recovery	Base Cost of Gas Change G011/MR10-978	Demand Change Nov '12 12-1193	Last Demand Change Jan '13 10-977	Most Recent PGA Aug. 2013	Nov13 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$4.7461	$3.4651	$3.4576	$3.8105	$4.0047	-15.62%	15.82%	5.10%	$0.1942
Demand Rate	$19.5620	$19.3628	$19.3628	$19.4140	$16.9452	-13.38%	-12.49%	-12.72%	($2.4688)
Comm. Margin	$0.3568	$0.3554	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
LV Dem. Margin	$2.3000	$1.5319	$2.3000	$2.3000	$2.3000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$5.1029	$3.8205	$3.8144	$4.1673	$4.3615	-14.53%	14.34%	4.66%	$0.1942
Total Demand Cost	$21.8620	$20.8947	$21.6628	$21.7140	$19.2452	-11.97%	-11.16%	-11.37%	($2.4688)
Avg. Annual Bill*	$77,371.79	$58,267.14	$58,234.22	$63,475.45	$66,171.67	-14.48%	13.63%	4.25%	$2,696.22
Effect of proposed commodity change on average annual bills:									$2,881.38
Effect of proposed demand change on average annual bills:									($185.16)

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

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.1184	3.04%	11.84%	($0.1581)	-9.32%	(0.0397)		-0.52%
Sm Vol Inter. Service	$0.1184	3.04%	11.84%	$0.0000	0.00%	0.1184		2.39%
Lrg Vol Inter. Service	$0.1942	5.10%	19.42%	$0.0000	0.00%	0.1942		4.66%
Sm Vol Joint Service	$0.1942	5.10%	19.42%	($2.0509)	-10.56%	0.1942	***	3.98%
Lrg Vol Joint Service	$0.1942	5.10%	19.42%	($2.4688)	-12.72%	0.1942	***	4.66%

*** Joint total change includes only commodity change since not all joint customers purchase CD units.

Attachment 12

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2013 Change in Entitlement Levels and Related Demand Costs

NNG

	Contract	Aug-13 PGA	Nov-13 Entitlement	Entitlement Change	Months	Nov-13 Rate/MCF	Aug-13 Total Cost	Entitlement Total Cost	Entitlement Change
TF-12-B (Max Rate)	112495	41,081	41,844	763	12	$ 7.5171	$3,804,925	$3,774,555	($30,370)
TF-12-B (Discount)	112495	5,200	5,200	0	12	$ 6.4818	$374,111	$404,464	$30,353
TF-12-V (Max Rate)	112495	29,035	29,035	0	12	$ 9.0926	$3,168,044	$3,168,044	($0)
TF-5 (Max Rate)	112495	32,278	31,515	(763)	5	$ 15.1530	$2,387,734	$2,387,734	($0)
TFX-12 (Max Rate)	112486	10,822	10,822	0	12	$ 9.6288	$1,250,434	$1,250,434	$0
TFX-12 (Discount)	111866	1,283	1,283	0	12	$ 4.8640	$74,886	$74,886	$0
TFX-12 (Discount)	111866	8,271	8,271	0	12	$ 5.4720	$543,107	$543,107	($0)
TFX-12 (Discount)	111866	11,921	11,921	0	12	$ 7.6025	$1,087,553	$1,087,553	($0)
TFX-5 (Max Rate)	112486	57,371	57,371	0	5	$ 15.1530	$4,346,714	$4,346,714	($0)
TFX-5 (Discount)	112486	1,800	1,800	0	5	$ 7.6000	$68,400	$68,400	$0
TFX-5 (Discount)	111866	379	379	0	5	$ 4.8640	$9,217	$9,217	$0
TFX-5 (Discount)	111866	2,445	2,445	0	5	$ 5.4720	$66,895	$66,895	$0
TFX-5 (Discount)	111866	22,189	22,189	0	5	$ 15.1392	$1,679,619	$1,679,619	($0)
TFX-5 (Discount)	112561	6,000	6,000	0	5	$ 4.5600	$136,800	$136,800	$0
TFX Apr (Max Rate)	112486	2,000	2,000	0	1	$ 5.6830	$11,366	$11,366	$0
TFX Oct (Max Rate)	112486	2,000	2,000	0	1	$ 5.6830	$11,366	$11,366	$0
SMS Charge		22,680	22,680	0	12	$ 2.1800	$593,309	$593,309	($0)
WINDOM		2,500	2,500	0	12	$ -	$0	$0	$0
Northwestern Energy		910	910	0	12	$ 8.0000	$87,360	$87,360	$0
NNG Zone GDD Call Option		0	20,000	20,000	3	$ 0.9000	$0	$54,000	$54,000
Bison		50,000	50,000	0	12	$ 17.4896	$10,493,750	$10,493,750	$0
NBPL		50,000	50,000	0	12	$ 6.9958	$4,197,500	$4,197,500	$0
FDD: Storage Reservation		91,913	91,913	0	12	$ 1.7140	$1,890,467	$1,890,467	($0)
FDD: Storage Reservation		5,550	5,550	0	12	$ 3.3157	$220,826	$220,826	($0)
FDD: Storage Cycle Volume		1,059,864	1,059,864	0	5	$ 0.3567	$1,890,267	$1,890,267	$0
FDD: Storage Cycle Volume		64,000	64,000	0	5	$ 0.6901	$220,832	$220,832	$0
Total Demand Cost							$38,615,482	$38,669,465	$53,983

Costs Assigned In Commodity:	Aug-13 PGA	Nov-13 Entitlement	Entitlement Change	Months	Nov-13 Rate/MCF	Aug-13 Total Cost	Entitlement Total Cost	Entitlement Change
Upstream								
			0				$0	$0
Surcharges:			0				$0	$0
			0				$0	$0
Storage			0				$0	$0
FDD Withdrawal	5,619,321	5,619,321	0	1	$0.0000	$0	$0	$0
FDD Injection	5,619,321	5,619,321	0	1	$0.0000	$0	$0	$0
							$0	$0
							$0	$0
Producer Demand Payments/Option Premium						$1,428,138	$758,741	($669,397)
Total Commodity Costs						$1,428,138	$758,741	($669,397)

Attachment 13

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/12	0	0	0	0	0	47,629	35,875
7/2/12	0	0	0	0	0	60,941	35,875
7/3/12	0	0	0	0	0	56,519	35,875
7/4/12	0	0	0	0	0	45,639	35,875
7/5/12	1	0	0	0	0	61,802	36,183
7/6/12	0	0	0	0	0	66,578	35,875
7/7/12	0	0	0	0	0	56,055	35,875
7/8/12	0	0	0	0	0	47,123	35,875
7/9/12	0	0	0	0	0	50,549	35,875
7/10/12	0	0	0	0	0	51,377	35,875
7/11/12	0	0	0	0	0	52,144	35,875
7/12/12	0	0	0	0	0	60,219	35,875
7/13/12	0	0	0	0	0	51,084	35,875
7/14/12	0	0	0	0	0	49,717	35,875
7/15/12	0	0	0	0	0	49,624	35,875
7/16/12	0	0	0	0	0	58,482	35,875
7/17/12	0	0	0	0	0	64,567	35,875
7/18/12	0	0	0	0	0	50,151	35,875
7/19/12	0	0	0	0	0	49,815	35,875
7/20/12	0	0	0	0	0	49,973	35,875
7/21/12	0	0	0	0	0	50,671	35,875
7/22/12	0	0	0	0	0	51,526	35,875
7/23/12	0	0	0	0	0	65,497	35,875
7/24/12	0	0	0	0	0	58,243	35,875
7/25/12	0	0	0	0	0	56,852	35,875
7/26/12	1	0	0	0	0	48,309	36,177
7/27/12	0	0	0	0	0	42,853	35,875
7/28/12	0	0	0	0	0	42,720	35,875
7/29/12	0	0	0	0	0	49,078	35,875
7/30/12	0	0	0	0	0	56,200	35,875
7/31/12	0	0	0	0	0	57,853	35,875
8/1/12	0	0	0	0	0	53,332	35,875
8/2/12	0	0	0	0	0	51,384	35,875
8/3/12	0	0	0	0	0	48,571	35,875
8/4/12	2	0	1	0	1	46,022	37,725
8/5/12	0	0	0	0	0	47,802	35,875
8/6/12	0	0	0	0	0	51,620	35,875
8/7/12	4	0	0	0	0	54,752	37,050
8/8/12	4	0	0	0	1	47,164	37,131
8/9/12	5	0	0	0	1	44,205	37,401
8/10/12	4	0	2	5	2	42,509	40,853
8/11/12	0	0	3	0	1	44,171	39,320
8/12/12	1	0	0	7	1	44,631	38,021

Attachment 13

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Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

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Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
8/13/12	2	0	0	0	0	47,866	36,474
8/14/12	0	0	0	0	0	51,617	35,875
8/15/12	9	1	6	0	4	51,196	45,571
8/16/12	8	3	6	8	6	48,506	49,751
8/17/12	3	0	3	3	2	42,063	41,231
8/18/12	7	0	1	4	2	47,915	40,375
8/19/12	8	0	2	3	2	53,407	41,527
8/20/12	4	0	1	1	1	53,437	38,577
8/21/12	0	0	0	0	0	51,433	35,875
8/22/12	0	0	0	0	0	49,339	35,875
8/23/12	0	0	0	0	0	47,334	35,875
8/24/12	0	0	0	0	0	44,673	35,875
8/25/12	0	0	0	0	0	44,983	35,875
8/26/12	0	0	0	0	0	47,971	35,875
8/27/12	0	0	0	0	0	50,918	35,875
8/28/12	0	0	0	0	0	53,017	35,875
8/29/12	0	0	0	0	0	53,098	35,875
8/30/12	0	0	0	0	0	46,458	35,875
8/31/12	1	0	0	0	0	42,284	36,180
9/1/12	0	0	0	0	0	43,041	35,875
9/2/12	0	0	0	0	0	43,762	35,875
9/3/12	0	0	0	0	0	47,351	35,875
9/4/12	0	0	0	0	0	52,921	35,875
9/5/12	1	0	0	2	0	44,858	36,776
9/6/12	10	2	7	0	5	43,669	47,673
9/7/12	14	1	3	11	5	46,329	47,621
9/8/12	8	2	4	2	4	44,895	45,109
9/9/12	3	0	1	1	1	47,681	38,387
9/10/12	0	0	0	0	0	49,070	35,875
9/11/12	6	0	1	0	1	45,429	38,975
9/12/12	10	1	4	15	5	48,716	48,244
9/13/12	13	1	3	5	4	51,039	45,483
9/14/12	9	0	1	0	2	46,950	39,883
9/15/12	2	0	0	0	0	48,591	36,497
9/16/12	19	10	11	1	10	50,511	60,646
9/17/12	23	15	16	17	17	58,188	75,460
9/18/12	11	2	5	14	6	59,071	49,718
9/19/12	15	8	13	8	11	57,074	62,660
9/20/12	21	15	13	9	14	57,371	69,062
9/21/12	26	18	21	16	20	57,910	83,666
9/22/12	24	18	21	25	21	71,676	85,929
9/23/12	10	6	10	16	10	65,483	58,997
9/24/12	21	8	4	4	8	56,010	53,660

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
9/25/12	22	14	9	12	12	57,745	65,257
9/26/12	19	10	9	18	12	57,154	63,844
9/27/12	12	4	6	10	7	51,554	52,032
9/28/12	13	0	0	3	2	47,534	40,407
9/29/12	10	3	1	0	3	44,784	42,151
9/30/12	9	2	2	0	3	46,556	42,384
10/1/12	17	7	4	15	8	63,605	54,502
10/2/12	8	1	2	7	3	64,259	43,218
10/3/12	22	14	16	9	16	63,270	72,630
10/4/12	32	28	24	27	26	79,231	98,210
10/5/12	30	28	28	30	28	87,848	103,035
10/6/12	28	27	27	36	28	95,990	102,747
10/7/12	26	13	14	24	16	91,070	74,329
10/8/12	29	24	22	9	22	82,792	87,466
10/9/12	28	23	24	31	25	95,198	95,406
10/10/12	31	23	26	22	25	88,968	96,148
10/11/12	33	27	26	34	28	102,262	102,478
10/12/12	23	16	9	28	15	84,565	70,943
10/13/12	19	14	17	13	16	72,001	73,965
10/14/12	21	16	16	20	17	80,059	76,216
10/15/12	11	7	7	10	8	68,391	54,477
10/16/12	17	11	13	3	12	66,178	63,365
10/17/12	18	20	20	24	20	70,805	83,931
10/18/12	24	20	22	27	22	74,261	88,792
10/19/12	24	21	21	28	22	75,162	88,817
10/20/12	20	9	8	20	11	74,480	61,901
10/21/12	20	9	6	11	9	61,915	57,994
10/22/12	21	5	0	15	6	63,826	49,874
10/23/12	16	12	0	13	7	56,898	52,145
10/24/12	30	27	22	31	25	57,514	95,528
10/25/12	34	32	32	37	33	91,186	113,612
10/26/12	34	31	28	39	31	95,437	108,877
10/27/12	34	29	28	35	30	89,148	106,220
10/28/12	28	29	29	27	28	92,507	102,841
10/29/12	28	29	27	27	27	104,972	100,880
10/30/12	36	29	29	29	30	102,006	106,680
10/31/12	25	20	23	25	23	91,671	89,577
11/1/12	39	30	31	31	32	95,799	110,874
11/2/12	33	29	26	35	29	93,545	103,956
11/3/12	38	29	25	28	28	91,317	102,003
11/4/12	35	26	22	26	25	81,261	95,766
11/5/12	30	25	25	31	26	88,791	98,025
11/6/12	30	26	26	31	27	90,902	99,839

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013
NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
11/7/12	28	27	27	27	27	91,005	99,316
11/8/12	25	22	22	22	23	79,703	89,327
11/9/12	33	19	21	23	22	73,573	88,062
11/10/12	26	15	9	24	15	54,900	70,528
11/11/12	41	43	41	51	43	109,726	136,985
11/12/12	48	46	48	46	47	134,622	147,906
11/13/12	39	34	35	30	35	104,254	117,626
11/14/12	27	22	22	25	23	83,951	90,849
11/15/12	39	29	29	37	31	91,686	109,882
11/16/12	34	31	27	32	30	90,405	105,647
11/17/12	20	20	20	22	20	71,415	83,616
11/18/12	17	15	16	20	16	68,043	74,804
11/19/12	26	20	22	27	22	78,484	88,934
11/20/12	29	20	21	20	21	80,392	86,183
11/21/12	23	11	6	12	10	58,136	59,835
11/22/12	36	32	29	36	31	87,248	110,228
11/23/12	60	51	53	51	53	127,535	161,285
11/24/12	51	45	46	42	46	111,071	144,206
11/25/12	57	50	43	46	47	117,674	147,180
11/26/12	58	51	53	51	53	142,798	160,581
11/27/12	45	39	43	44	42	127,749	135,045
11/28/12	46	35	37	37	38	115,239	124,752
11/29/12	44	33	28	35	32	104,397	112,019
11/30/12	36	32	32	36	33	101,069	114,565
12/1/12	31	27	26	27	27	84,643	99,954
12/2/12	28	26	25	21	25	84,861	95,130
12/3/12	36	24	21	28	24	83,670	93,297
12/4/12	52	43	40	37	42	121,172	134,408
12/5/12	41	36	38	32	37	111,738	123,695
12/6/12	41	34	33	31	34	101,868	116,335
12/7/12	45	37	38	43	39	111,975	128,748
12/8/12	43	38	35	40	38	104,792	124,655
12/9/12	53	50	47	61	50	127,585	154,154
12/10/12	58	58	59	59	58	155,929	174,142
12/11/12	61	50	48	45	50	145,100	153,068
12/12/12	48	33	36	40	37	112,070	123,708
12/13/12	54	37	38	45	41	116,734	131,823
12/14/12	42	39	36	33	37	99,015	124,531
12/15/12	33	33	32	41	34	92,792	115,195
12/16/12	46	43	44	50	45	125,192	141,620
12/17/12	46	43	43	43	43	127,732	137,711
12/18/12	43	40	39	44	40	118,017	130,562
12/19/12	42	41	40	47	41	116,472	133,670

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
12/20/12	61	55	61	64	60	152,631	177,466
12/21/12	57	53	58	60	56	152,622	169,411
12/22/12	56	49	48	55	50	135,222	154,759
12/23/12	60	54	51	61	54	140,421	164,144
12/24/12	71	62	61	71	64	153,764	186,355
12/25/12	67	60	62	68	63	162,774	184,404
12/26/12	58	54	55	62	56	162,322	167,968
12/27/12	54	51	52	56	53	144,611	160,552
12/28/12	52	47	49	58	50	133,296	153,812
12/29/12	59	59	63	60	61	166,422	179,810
12/30/12	60	56	58	52	57	152,791	170,796
12/31/12	68	65	68	66	67	182,002	194,173
1/1/13	63	60	66	58	63	174,632	184,754
1/2/13	51	51	53	55	53	166,490	160,161
1/3/13	56	53	59	64	57	170,477	171,615
1/4/13	45	46	51	51	49	146,433	151,720
1/5/13	48	50	54	56	52	144,471	159,312
1/6/13	51	46	55	55	52	150,148	158,707
1/7/13	42	40	46	47	44	134,810	140,230
1/8/13	45	40	45	45	44	129,675	139,421
1/9/13	42	39	43	38	41	130,281	133,229
1/10/13	29	33	36	35	34	117,288	117,012
1/11/13	35	42	39	49	41	129,557	132,141
1/12/13	61	63	62	67	63	186,103	184,129
1/13/13	64	64	63	63	64	192,959	186,388
1/14/13	63	57	55	57	57	179,032	169,693
1/15/13	54	47	48	50	49	148,231	151,552
1/16/13	57	48	47	49	49	164,871	151,638
1/17/13	66	52	50	47	52	176,165	158,951
1/18/13	51	33	32	29	34	131,881	116,448
1/19/13	63	54	53	51	54	174,215	164,510
1/20/13	81	74	73	73	74	210,322	211,443
1/21/13	87	80	78	76	80	236,124	224,015
1/22/13	78	67	67	60	68	205,228	195,547
1/23/13	79	67	67	70	69	213,008	198,551
1/24/13	73	64	66	66	66	199,406	191,924
1/25/13	67	59	60	58	60	183,865	178,769
1/26/13	63	50	54	52	54	156,267	162,836
1/27/13	42	35	37	34	37	133,051	123,068
1/28/13	37	36	34	36	35	125,419	119,107
1/29/13	48	43	44	50	45	135,099	141,857
1/30/13	67	64	65	70	65	179,102	190,521
1/31/13	84	81	82	81	82	218,269	229,447

Attachment 13

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
2/1/13	78	73	70	63	71	193,054	203,711
2/2/13	69	62	59	55	61	170,709	179,524
2/3/13	73	60	59	54	60	171,433	178,856
2/4/13	64	53	56	52	56	164,429	167,141
2/5/13	58	52	52	41	52	160,827	158,221
2/6/13	51	52	43	40	46	144,634	145,116
2/7/13	48	47	44	49	46	150,611	144,210
2/8/13	49	50	46	46	48	144,002	148,307
2/9/13	44	44	42	35	42	135,433	135,738
2/10/13	44	40	39	44	40	136,362	131,047
2/11/13	52	49	51	51	50	157,796	155,159
2/12/13	45	40	42	42	42	134,937	134,698
2/13/13	37	36	38	36	37	124,450	123,963
2/14/13	59	51	51	53	52	151,848	158,917
2/15/13	63	60	61	54	60	172,204	177,992
2/16/13	61	54	54	48	54	164,311	163,821
2/17/13	50	47	49	38	47	137,382	147,601
2/18/13	63	53	57	63	57	173,152	170,939
2/19/13	76	69	76	75	74	205,258	211,035
2/20/13	62	58	59	64	60	181,007	177,128
2/21/13	54	52	55	54	54	158,926	163,577
2/22/13	44	43	47	53	46	138,065	145,505
2/23/13	47	46	56	50	51	145,551	156,811
2/24/13	42	41	49	45	45	130,121	142,851
2/25/13	47	39	37	45	40	132,494	129,390
2/26/13	41	37	41	43	40	129,231	130,119
2/27/13	39	35	40	47	39	129,151	128,465
2/28/13	46	42	44	46	44	141,738	140,041
3/1/13	62	48	52	53	52	145,971	158,664
3/2/13	47	42	47	46	46	136,167	143,589
3/3/13	46	42	46	42	44	132,302	140,963
3/4/13	45	43	46	41	44	145,628	140,412
3/5/13	52	43	50	51	48	143,519	150,552
3/6/13	58	46	59	48	54	150,538	162,809
3/7/13	47	44	52	44	48	134,255	150,009
3/8/13	39	37	39	36	38	120,693	125,448
3/9/13	35	32	34	38	34	112,801	115,952
3/10/13	42	38	40	56	42	130,326	134,213
3/11/13	46	42	48	51	46	133,799	145,320
3/12/13	57	48	54	54	53	140,774	160,038
3/13/13	44	40	47	47	44	131,859	141,036
3/14/13	35	30	39	29	35	109,852	118,358
3/15/13	52	42	41	39	43	119,229	136,522

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013
NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
3/16/13	67	52	53	53	54	132,213	164,165
3/17/13	47	46	45	49	46	124,082	144,571
3/18/13	56	60	63	62	61	154,760	180,355
3/19/13	62	59	63	56	61	160,603	180,175
3/20/13	60	54	62	54	59	159,807	174,417
3/21/13	50	44	51	49	49	142,540	151,188
3/22/13	43	37	43	42	41	116,055	133,446
3/23/13	34	33	36	43	36	102,172	120,672
3/24/13	46	40	44	44	43	115,939	137,671
3/25/13	35	35	42	48	40	110,073	130,114
3/26/13	32	35	40	40	38	110,322	125,420
3/27/13	37	31	37	34	35	106,783	117,939
3/28/13	33	29	35	26	32	97,178	111,298
3/29/13	23	23	27	18	24	83,179	93,461
3/30/13	26	22	30	24	27	82,832	98,579
3/31/13	49	41	44	42	43	111,674	138,501
4/1/13	47	40	44	39	43	120,420	136,574
4/2/13	41	32	36	33	35	113,973	119,680
4/3/13	29	20	26	25	24	93,843	93,599
4/4/13	39	29	32	30	32	90,004	110,799
4/5/13	36	23	24	27	25	96,162	95,854
4/6/13	32	25	25	29	26	83,279	97,897
4/7/13	31	23	18	23	22	79,160	87,186
4/8/13	34	31	33	26	32	86,330	111,485
4/9/13	38	33	38	41	37	108,189	123,176
4/10/13	44	35	37	36	37	117,936	123,468
4/11/13	41	35	37	34	37	122,226	122,250
4/12/13	40	34	36	38	36	110,855	121,754
4/13/13	48	35	34	38	36	105,505	121,386
4/14/13	35	33	33	37	34	111,739	115,461
4/15/13	31	27	29	38	30	105,770	105,836
4/16/13	37	29	32	34	32	91,999	112,133
4/17/13	37	36	36	37	36	112,510	121,598
4/18/13	47	38	38	48	41	117,816	131,703
4/19/13	43	35	32	46	36	110,933	120,650
4/20/13	36	25	26	39	28	93,046	102,855
4/21/13	33	30	31	26	30	87,912	107,403
4/22/13	35	32	35	45	35	104,746	119,065
4/23/13	36	28	30	42	32	105,351	110,569
4/24/13	31	25	27	32	27	92,772	100,805
4/25/13	17	6	8	22	10	79,465	60,359
4/26/13	17	6	9	12	10	53,110	58,400
4/27/13	13	0	8	6	6	44,513	50,028

Attachment 13

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013
NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
4/28/13	14	2	4	3	5	47,378	47,153
4/29/13	13	0	2	3	3	48,602	43,258
4/30/13	28	22	27	18	25	51,012	94,029
5/1/13	32	26	39	37	34	91,584	116,588
5/2/13	36	34	39	34	36	100,592	122,161
5/3/13	33	25	27	32	28	102,437	101,408
5/4/13	23	13	17	32	18	76,488	79,455
5/5/13	14	4	7	21	9	56,407	56,748
5/6/13	10	0	1	13	3	45,262	43,740
5/7/13	11	0	2	2	3	43,148	42,136
5/8/13	25	16	16	10	16	45,970	73,929
5/9/13	26	13	14	20	16	64,276	73,476
5/10/13	29	20	25	16	23	53,455	90,636
5/11/13	28	20	23	28	23	67,964	90,907
5/12/13	19	9	17	14	15	65,776	70,461
5/13/13	10	0	0	0	1	52,051	38,701
5/14/13	1	0	1	0	1	44,367	37,422
5/15/13	9	0	0	1	1	43,074	38,677
5/16/13	18	5	9	0	8	43,154	54,274
5/17/13	21	0	0	0	3	44,586	42,039
5/18/13	17	0	0	0	2	39,408	40,716
5/19/13	22	0	0	1	3	41,341	42,537
5/20/13	21	10	4	5	8	45,767	54,637
5/21/13	18	16	11	14	14	50,155	68,182
5/22/13	21	11	14	21	15	55,696	70,513
5/23/13	18	10	13	14	13	52,433	66,331
5/24/13	18	8	15	2	12	42,167	63,942
5/25/13	15	9	17	11	14	44,380	68,927
5/26/13	16	7	12	11	11	44,506	62,255
5/27/13	12	7	7	9	8	48,376	54,937
5/28/13	6	0	0	4	1	45,685	38,887
5/29/13	5	0	0	0	1	43,257	37,431
5/30/13	2	0	0	0	0	45,018	36,486
5/31/13	15	3	6	3	6	41,637	49,602
6/1/13	14	7	12	13	11	41,695	61,575
6/2/13	16	4	10	8	9	43,862	56,427
6/3/13	13	4	11	0	8	43,417	55,183
6/4/13	18	9	8	8	10	47,217	58,639
6/5/13	16	11	8	10	10	49,863	59,037
6/6/13	10	5	5	15	7	50,805	52,219
6/7/13	8	0	3	5	3	43,384	43,450
6/8/13	15	1	1	8	4	36,991	44,624
6/9/13	8	0	0	1	1	40,462	38,551

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

NNG

Base	35,875
Variable	2,365

Date	12.29% Cloquet Adjusted HDD	28.34% Minneapolis Adjusted HDD	47.60% Rochester Adjusted HDD	11.77% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
6/10/13	0	0	0	0	0	42,452	35,875
6/11/13	1	0	0	0	0	41,579	36,183
6/12/13	2	0	0	3	1	43,982	37,446
6/13/13	7	0	0	0	1	43,313	38,032
6/14/13	3	0	0	0	0	40,101	36,782
6/15/13	0	0	0	0	0	36,422	35,875
6/16/13	19	0	0	0	2	37,803	41,475
6/17/13	14	0	0	0	2	42,458	39,806
6/18/13	2	0	0	0	0	42,456	36,480
6/19/13	6	0	0	0	1	42,646	37,742
6/20/13	4	0	0	0	1	41,775	37,119
6/21/13	11	0	0	0	1	38,239	38,986
6/22/13	0	0	0	0	0	35,685	35,875
6/23/13	0	0	0	0	0	39,196	35,875
6/24/13	0	0	0	0	0	40,199	35,875
6/25/13	0	0	0	0	0	40,701	35,875
6/26/13	0	0	0	0	0	41,496	35,875
6/27/13	0	0	0	0	0	39,284	35,875
6/28/13	3	0	0	0	0	39,860	36,791
6/29/13	0	0	0	0	0	45,064	35,875
6/30/13	6	0	4	0	3	43,107	42,497
Totals	10,282	8,406	8,786	9,175	8,908	33,063,198	34,161,416

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

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

MINNESOTA ENERGY RESOURCES - NNG

Customer Counts by PGAC Class - July 1, 2012 through June 30, 2013

Rate Class	Tariff Rate Designation	Jul-12 Average Customers	Aug-12 Average Customers	Sep-12 Average Customers	Oct-12 Average Customers	Nov-12 Average Customers	Dec-12 Average Customers	Jan-13 Average Customers	Feb-13 Average Customers	Mar-13 Average Customers	Apr-13 Average Customers	May-13 Average Customers	Jun-13 Average Customers
Residential w/ Heat	MN001/007/008	143,475	143,858	144,119	144,676	145,031	145,312	145,395	145,402	145,399	145,013	144,373	144,538
Residential w/o Heat	MN002/009/010	931	931	931	938	939	938	937	938	937	927	910	918
Commercial-SV	MN048/050/053/054/070/076/078	7,345	7,340	7,334	7,378	7,414	7,430	7,437	7,434	7,438	7,403	7,349	7,357
Commercial-LV	MN049/056/060/063/064/065/071/077/756	6,679	6,677	6,689	6,705	6,747	6,752	6,763	6,762	6,763	6,752	6,734	6,733
SV-Joint	MN704	3	3	3	3	3	3	3	3	3	3	4	3
SV-Interruptible	MN125/128/129/735	265	264	265	265	263	261	262	261	261	260	259	261
LV-Interruptible	MN200/201/207/720/721	52	53	53	54	54	53	53	54	54	54	56	55
Transport	MN710	2	2	2	2	2	2	2	2	2	2	2	2
Transport	MN790	1	1	1	1	1	1	1	1	1	1	1	1
Transport	MN789/714	1	2	2	2	2	4	5	5	5	3	1	2
Transport	MN718	1	1	1	1	1	1	1	1	1	1	1	1
Transport	MN705	12	12	12	12	12	12	12	12	12	12	12	12
Transport	MN703	2	2	2	2	2	2	2	3	3	4	7	8
Transport	MN/704/739	4	4	4	4	4	4	4	4	4	4	4	4
Transport	MN/712/713	3	3	3	3	3	3	3	3	3	1	0	0
Transport	MN/714	8	7	7	7	7	7	7	7	7	8	8	8
Transport	MN/715	0	0	0	0	0	1	1	1	1	1	1	0
Transport	MN/721	2	2	2	2	2	2	2	2	2	2	2	2
Transport	MN/752	0	0	0	0	0	0	0	1	1	1	0	0
Transport	MN/799	1	1	1	1	1	1	1	1	1	1	1	1
Transport	MN/751/761/82L/781/701/702/706	51	51	51	51	51	52	50	50	50	54	53	54
Transport	MN766	11	11	11	11	11	11	11	11	11	9	7	7
Transport	MN/700	1	1	1	1	1	1	1	1	1	1	1	1
Transport	MN/750	2	2	2	2	2	2	2	1	1	1	1	0
Transport	MN/774	1	1	1	1	1	0	0	0	0	0	0	0
Transport	MN/745	1	1	1	1	1	1	1	1	1	1	1	1
Total		158,854	159,230	159,498	160,123	160,555	160,856	160,956	160,961	160,962	160,519	159,788	159,969

Note: Customer counts do not include NMU-NNG. MERC was not able to separate out customer counts by pipeline for NMU to include in consolidated NNG

MINNESOTA ENERGY RESOURCES - NNG

Projected Fixed Cost - November 2013 through March 2014

Futures Contracts WACOG

NNG-PNG Futures

Nov-13						30
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/17/13	56,667	$ 4.1999	$ 237,994	$ 3.8690	$ 219,243	$ 18,751
06/19/13	56,667	$ 4.0540	$ 229,727	$ 3.8690	$ 219,243	$ 10,483
07/19/13	56,667	$ 3.8580	$ 218,620	$ 3.8690	$ 219,243	$ (623)
TBD	56,667		$ -		$ -	$ -
TBD	56,667		$ -		$ -	$ -
TBD	56,667		$ -		$ -	$ -
Total	340,000		$ 686,341		$ 657,730	$ 28,611
WACOG			$ 4.0373		3.869	$ 0.1683

Dec-13						31
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/03/13	-	$ 4.3820	$ -	$ 4.0440	$ -	$ -
05/03/13	-	$ 4.3830	$ -	$ 4.0440	$ -	$ -
06/04/13	-	$ 4.2420	$ -	$ 4.0440	$ -	$ -
07/02/13	-	$ 3.8980	$ -	$ 4.0440	$ -	$ -
TBD	-		$ -	$ 4.0440	$ -	$ -
TBD	-		$ -	$ 4.0440	$ -	$ -
TBD	-		$ -	$ 4.0440	$ -	$ -
Total	-		$ -		$ -	$ -
WACOG			#DIV/0!		#DIV/0!	#DIV/0!

Jan-14						31
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/23/13	53,333	$ 4.6130	$ 246,027	$ 3.9460	$ 210,453	$ 35,573
06/24/13	6,667	$ 4.0980	$ 27,320	$ 3.9460	$ 26,307	$ 1,013
06/24/13	46,667	$ 4.0990	$ 191,287	$ 3.9460	$ 184,147	$ 7,140
07/24/13	53,333	$ 4.0210	$ 214,453	$ 3.9460	$ 210,453	$ 4,000
TBD	46,667		$ -		$ -	$ -
TBD	46,667		$ -		$ -	$ -
TBD	46,667		$ -		$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
Total	300,000		$ 679,087		$ 631,360	$ 47,727
WACOG			$ 4.2443		$ 3.9460	$ 0.1591

Feb-14						28
Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/07/13	5,714	$ 4.3480	$ 24,846	$ 3.9480	$ 22,560	$ 2,286
05/07/13	17,143	$ 4.3490	$ 74,554	$ 3.9480	$ 67,680	$ 6,874
06/11/13	11,429	$ 4.0940	$ 46,789	$ 3.9480	$ 45,120	$ 1,669
06/11/13	11,429	$ 4.0950	$ 46,800	$ 3.9480	$ 45,120	$ 1,680
07/09/13	28,571	$ 3.9830	$ 113,800	$ 3.9480	$ 112,800	$ 1,000
TBD	28,571		$ -		$ -	$ -
TBD	28,571		$ -		$ -	$ -
TBD	28,571					
Total	160,000		$ 306,789		$ 293,280	$ 13,509
WACOG			$ 4.1298		$ 3.9480	$ 0.0844

Mar-14						31
Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/29/13	111,364	$ 4.4130	$ 491,448	$ 3.9130	$ 435,766	$ 55,682
06/27/13	111,364	$ 3.8820	$ 432,314	$ 3.9130	$ 435,766	$ (3,452)
TBD	119,318		$ -		$ -	$ -
TBD	119,318		$ -		$ -	$ -
TBD	119,318		$ -		$ -	$ -
TBD	119,318		$ -		$ -	$ -
Total	700,000		$ 923,761		$ 871,532	$ 52,230
WACOG			$ 4.1475		$ 3.9130	$ 0.0746

Total						
	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	227,078	$ 4.4052	$ 1,000,314	$ 3.9107	$ 888,023	$ 112,292
	191,840	$ 3.9820	$ 763,915	$ 3.9043	$ 748,996	$ 14,919
	234,080	$ 1.9510	$ 456,695	$ 1.9161	$ 448,510	$ 8,185
	240,747	$ 1.0852	$ 261,253	$ 1.0616	$ 255,573	$ 5,680
	251,223	$ 0.4530	$ 113,800	$ 0.4490	$ 112,800	$ 1,000
	251,223	$ -	$ -	$ -	$ -	$ -
	75,238	$ -	$ -	$ -	$ -	$ -
	28,571	$ -	$ -	$ -	$ -	$ -
	1,500,000		$ 2,595,978		$ 2,453,902	$ 142,076
			$ 4.1402		$ 3.9136	$ 0.0947

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2013 through March 2014

Month/ Year	K#118657 NNG Storage	Storage K#125344 LS Power	Storage K#125345 LS Power	Total NNG Storage	Projected Storage NNG WACOG	K#118657 NNG Storage Cost	K#125344 NNG Storage Cost	K#125345 NNG Storage Cost	Total NNG Storage Cost	AECO Storage GLGT/VGT Centra Emerson	AECO Storage GLGT/VGT Centra Emerson WACOG	AECO Storage GLGT/VGT Centra Emerson Cost
Nov-13	455,259	73,125	19,500	547,884	$ 3.6991	$ 1,684,071	$ 270,500	$ 72,133	$ 2,026,705	85,304	$ 3.2341	$ 275,885
Dec-13	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 4,231,767	$ 679,719	$ 181,258	$ 5,092,744	231,769	$ 3.2341	$ 749,574
Jan-14	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 4,231,767	$ 679,719	$ 181,258	$ 5,092,744	231,769	$ 3.2341	$ 749,574
Feb-14	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 4,231,767	$ 679,719	$ 181,258	$ 5,092,744	209,339	$ 3.2341	$ 677,033
Mar-14	455,259	73,125	19,500	547,884	$ 3.6991	$ 1,684,071	$ 270,500	$ 72,133	$ 2,026,705	96,374	$ 3.2341	$ 311,687
Total	4,342,470	697,500	186,000	5,225,970	$ 3.6991	$16,063,444	$ 2,580,157	$ 688,042	$19,331,642	854,555	$ 3.2341	$ 2,763,755

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson LDS + Basis	Emerson LDS + Cost
Nov-13	547,884	$ 3.7710	$ 2,066,071	85,304	$ 3.9835	$ 339,808
Dec-13	1,376,734	$ 3.9390	$ 5,422,955	231,769	$ 4.1015	$ 950,601
Jan-14	1,376,734	$ 4.0235	$ 5,539,289	231,769	$ 4.0960	$ 949,326
Feb-14	1,376,734	$ 4.0205	$ 5,535,159	209,339	$ 4.0955	$ 857,348
Mar-14	547,884	$ 3.9680	$ 2,174,004	96,374	$ 4.0680	$ 392,049
Total	5,225,970	$ 3.9682	$20,737,478	854,555	$ 4.0830	$ 3,489,132

Max NNG Storage (Storage plan withdrawals through Apr 14)	5,225,970	5,669,321	06/30/13 Storage Balance - NNG	1,070,673	18.89%	986,944
Max AECO Storage	854,555	947,820	06/30/13 Storage Balance - AECO	376,065	39.68%	339,060
						39.68%

Month/ Year	K#118657 NNG Storage	Storage K#125344 LS Power	Storage K#125345 LS Power	Total NNG Storage	Projected K#118657 NNG WACOG	Projected K#125344 NNG WACOG	K#118657 K#125345 NNG WACOG	WACOG NNG PNG Cost	Projected NNG Indexes Price	Projected NNG Index Cost	Additional Storage (Savings)/ Cost
Nov-13	455,259	73,125	19,500	547,884	$ 3.6991	$ 3.6991	$ 3.6991	$ 2,026,705	$ 3.7710	$ 2,066,071	$ (39,366)
Dec-13	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 3.6991	$ 3.6991	$ 5,092,744	$ 3.9390	$ 5,422,955	$ (330,211)
Jan-14	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 3.6991	$ 3.6991	$ 5,092,744	$ 4.0235	$ 5,539,289	$ (446,545)
Feb-14	1,143,984	183,750	49,000	1,376,734	$ 3.6991	$ 3.6991	$ 3.6991	$ 5,092,744	$ 4.0205	$ 5,535,159	$ (442,415)
Mar-14	455,259	73,125	19,500	547,884	$ 3.6991	$ 3.6991	$ 3.6991	$ 2,026,705	$ 3.9680	$ 2,174,004	$ (147,299)
Total	4,342,470	697,500	186,000	5,225,970	$ 3.6991	$ 3.6991	$ 3.6991	$ 19,331,642	$ 3.9682	$ 20,737,478	$ (1,405,835)
								$ 3.6991	$ (0.2690)	$ (1,405,835)	

Month/ Year	AECO Storage	AECO Storage Other WACOG	Total AECO Cost	Projected Emerson Index Price	Projected Emerson Index Cost	Additional Storage (Savings)/ Cost
Nov-13	85,304	$ 3.2341	$ 275,885	$ 3.9835	$ 339,808	$ (63,923)
Dec-13	231,769	$ 3.2341	$ 749,574	$ 4.1015	$ 950,601	$ (201,026)
Jan-14	231,769	$ 3.2341	$ 749,574	$ 4.0960	$ 949,326	$ (199,751)
Feb-14	209,339	$ 3.2341	$ 677,033	$ 4.0955	$ 857,348	$ (180,315)
Mar-14	96,374	$ 3.2341	$ 311,687	$ 4.0680	$ 392,049	$ (80,362)
Total	854,555	$ 3.2341	$ 2,763,755	$ 4.0830	$3,489,132	$ (725,378)
			$ 3.2341	$ (0.8488)	$ (725,378)	

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2013 through March 2014

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-13

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/09/13		13	130,000	$ 4.2500	$ 552,500	$ 3.7060	$ 481,780	$ 3.7060	$ 481,780	$ -	$ 0.3100	$ 40,300	$ 522,080
2	06/13/13		14	140,000	$ 4.0000	$ 560,000	$ 3.7060	$ 518,840	$ 3.7060	$ 518,840	$ -	$ 0.2450	$ 34,300	$ 553,140
3	07/11/13		14	140,000	$ 3.7500	$ 525,000	$ 3.7060	$ 518,840	$ 3.7060	$ 518,840	$ -	$ 0.2150	$ 30,100	$ 548,940
4	TBD			-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
5	TBD			-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
6	TBD			-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.7060	$ -	$ -		$ -	$ -
Total			41	410,000		$ 1,637,500		$ 1,519,460		$ 1,519,460	$ -		$ 104,700	$ 1,624,160
						$ 3.9939		$ 3.7060		$ 3.7060	$ -		$ 0.2554	$ 3.9614
NNG-Cons	66	79.52%	33	330,000	$ 3.9458	$ 1,302,108	$ 3.6613	$ 1,208,245	$ 3.6613	$ 1,208,245	$ -	$ 0.2523	$ 83,255	$ 1,291,501
Other-Cons	17	20.48%	8	80,000	$ 4.1924	$ 335,392	$ 3.8902	$ 311,215	$ 3.8902	$ 311,215	$ -	$ 0.2681	$ 21,445	$ 332,659
Total	83	100.0%	41	410,000	$ 3.9939	$ 1,637,500	$ 3.7060	$ 1,519,460	$ 3.7060	$ 1,519,460	$ -	$ 0.2554	$ 104,700	$ 1,624,160

Dec-13

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/30/13		20	200,000	$ 4.5000	$ 900,000	$ 3.8690	$ 773,800	$ 3.8690	$ 773,800	$ -	$ 0.2500	$ 50,000	$ 823,800
2	06/26/13		20	200,000	$ 4.0000	$ 800,000	$ 3.8690	$ 773,800	$ 3.8690	$ 773,800	$ -	$ 0.2830	$ 56,600	$ 830,400
3				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
4				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
5				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
6				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.8690	$ -	$ -		$ -	$ -
Total			40	400,000		$ 1,700,000		$ 1,547,600		$ 1,547,600	$ -		$ 106,600	$ 1,654,200
						$ 4.2500		$ 3.8690		$ 3.8690	$ -		$ 0.2665	$ 4.1355
NNG-Cons	99	79.84%	32	320,000	$ 4.2414	$ 1,357,258	$ 3.8612	$ 1,235,584	$ 3.8612	$ 1,235,584	$ -	$ 0.2660	$ 85,108	$ 1,320,692
Other-Cons	25	20.16%	8	80,000	$ 4.2843	$ 342,742	$ 3.9002	$ 312,016	$ 3.9002	$ 312,016	$ -	$ 0.2686	$ 21,492	$ 333,508
Total	124	100.0%	40	400,000	$ 4.2500	$ 1,700,000	$ 3.8690	$ 1,547,600	$ 3.8690	$ 1,547,600	$ -	$ 0.2665	$ 106,600	$ 1,654,200

Jan-14

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/14/13		25	250,000	$ 4.5000	$ 1,125,000	$ 3.9460	$ 986,500	$ 3.9460	$ 986,500	$ -	$ 0.3520	$ 88,000	$ 1,074,500
2	06/18/13		26	260,000	$ 4.2500	$ 1,105,000	$ 3.9460	$ 1,025,960	$ 3.9460	$ 1,025,960	$ -	$ 0.3230	$ 83,980	$ 1,109,940
3				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
4				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
5				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
6				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.9460	$ -	$ -		$ -	$ -
Total	Total		51	510,000		$ 2,230,000		$ 2,012,460		$ 2,012,460	$ -		$ 171,980	$ 2,184,440
						$ 4.3725		$ 3.9460		$ 3.9460	$ -		$ 0.3372	$ 4.2832
NNG-Cons	125	81.17%	41	410,000	$ 4.4148	$ 1,810,065	$ 3.9841	$ 1,633,490	$ 3.9841	$ 1,633,490	$ -	$ 0.3405	$ 139,594	$ 1,773,084
Other-Cons	29	18.83%	10	100,000	$ 4.1994	$ 419,935	$ 3.7897	$ 378,970	$ 3.7897	$ 378,970	$ -	$ 0.3239	$ 32,386	$ 411,356
Total	154	100.0%	51	510,000	$ 4.3725	$ 2,230,000	$ 3.9460	$ 2,012,460	$ 3.9460	$ 2,012,460	$ -	$ 0.3372	$ 171,980	$ 2,184,440

Feb-14

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/21/13		23	230,000	$ 4.7500	$ 1,092,500	$ 3.9480	$ 908,040	$ 3.9480	$ 908,040	$ -	$ 0.3850	$ 88,550	$ 996,590
2	06/20/13		23	230,000	$ 4.2500	$ 977,500	$ 3.9480	$ 908,040	$ 3.9480	$ 908,040	$ -	$ 0.3520	$ 80,960	$ 989,000
3				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
4				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
5				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
6				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.9480	$ -	$ -		$ -	$ -
Total			46	460,000		$ 2,070,000		$ 1,816,080		$ 1,816,080	$ -		$ 169,510	$ 1,985,590
						$ 4.5000		$ 3.9480		$ 3.9480	$ -		$ 0.3685	$ 4.3165
NNG-Cons	115	82.14%	38	380,000	$ 4.4746	$ 1,700,357	$ 3.9257	$ 1,491,780	$ 3.9257	$ 1,491,780	$ -	$ 0.3664	$ 139,240	$ 1,631,020
Other-Cons	25	17.86%	8	80,000	$ 4.6205	$ 369,643	$ 4.0538	$ 324,300	$ 4.0538	$ 324,300	$ -	$ 0.3784	$ 30,270	$ 354,570
Total	140	100.0%	46	460,000	$ 4.5000	$ 2,070,000	$ 3.9480	$ 1,816,080	$ 3.9480	$ 1,816,080	$ -	$ 0.3685	$ 169,510	$ 1,985,590

Mar-14

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/02/13		18	180,000	$ 4.5000	$ 810,000	$ 3.9130	$ 704,340	$ 3.9130	$ 704,340	$ -	$ 0.4000	$ 72,000	$ 776,340
2	06/06/13		18	180,000	$ 4.2500	$ 765,000	$ 3.9130	$ 704,340	$ 3.9130	$ 704,340	$ -	$ 0.3230	$ 58,140	$ 762,480
3	07/0313		18	180,000	$ 4.0000	$ 720,000	$ 3.9130	$ 704,340	$ 3.9130	$ 704,340	$ -	$ 0.3500	$ 63,000	$ 767,340
4				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
5				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
6				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.9130	$ -	$ -		$ -	$ -
Total			54	540,000		$ 2,295,000		$ 2,113,020		$ 2,113,020	$ -		$ 193,140	$ 2,306,160
						$ 4.2500		$ 3.9130		$ 3.9130	$ -		$ 0.3577	$ 4.2707
NNG-Cons	92	81.42%	44	440,000	$ 4.2466	$ 1,868,496	$ 3.9099	$ 1,720,335	$ 3.9099	$ 1,720,335	$ -	$ 0.3574	$ 157,247	$ 1,877,582
Other-Cons	21	18.58%	10	100,000	$ 4.2650	$ 426,504	$ 3.9269	$ 392,685	$ 3.9269	$ 392,685	$ -	$ 0.3589	$ 35,893	$ 428,578
Total	113	100.0%	54	540,000	$ 4.2500	$ 2,295,000	$ 3.9130	$ 2,113,020	$ 3.9130	$ 2,113,020	$ -	$ 0.3577	$ 193,140	$ 2,306,160

Total

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			99	990,000	$ 4.5253	$ 4,480,000	$ 3.8934	$ 3,854,460	$ 3.8934	$ 3,854,460	$ -	$ 0.3423	$ 338,850	$ 4,193,310
2			101	1,010,000	$ 4.1658	$ 4,207,500	$ 3.8921	$ 3,930,980	$ 3.8921	$ 3,930,980	$ -	$ 0.3109	$ 313,980	$ 4,244,960
3			32	320,000	$ 3.8906	$ 1,245,000	$ 3.8224	$ 1,223,180	$ 3.8224	$ 1,223,180	$ -	$ 0.2909	$ 93,100	$ 1,316,280
4			0	-	#DIV/0!	$ -	#DIV/0!	$ -	#DIV/0!	$ -	$ -	#DIV/0!	$ -	$ -
5			0	-	#DIV/0!	$ -	#DIV/0!	$ -	#DIV/0!	$ -	$ -	#DIV/0!	$ -	$ -
6			0	-	#DIV/0!	$ -	#DIV/0!	$ -	#DIV/0!	$ -	$ -	#DIV/0!	$ -	$ -
7			0	-	#DIV/0!	$ -	#DIV/0!	$ -	#DIV/0!	$ -	$ -	#DIV/0!	$ -	$ -
8			0											
9			0											
10			0											
11			0											
12			0											
13			0											
14			0											
15			0											
Total			232	2,320,000		$ 9,932,500		$ 9,008,620		$ 9,008,620	$ -		$ 745,930	$ 9,754,550
						$ 4.2813		$ 3.8830		$ 3.8830	$ -		$ 0.3215	$ 4.2045
NNG-Cons	497	80.94%	188.00	1,880,000	$ 4.2765	$ 8,039,825	$ 3.8787	$ 7,291,994	$ 3.8787	$ 7,291,994	$ -	$ 0.3212	$ 603,790	$ 7,895,784
Other-Cons	117	19.06%	44.00	440,000	$ 4.3015	$ 1,892,675	$ 3.9014	$ 1,716,626	$ 3.9014	$ 1,716,626	$ -	$ 0.3230	$ 142,140	$ 1,858,766
Total	614	100.0%	232	2,320,000	$ 4.2813	$ 9,932,500	$ 3.8830	$ 9,008,620	$ 3.8830	$ 9,008,620	$ -	$ 0.3215	$ 745,930	$ 9,754,550

ATTACHMENT 4

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Kristin M. Stastny hereby certifies that on the 1st day of August, 2013, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of MERC's Petition for Approval of a Change in Demand Entitlement on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

/s/ Kristin M. Stastny
Kristin M. Stastny

Subscribed and sworn to before me
This 1st day of August, 2013.

/s/ Alice Jaworski
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Amber	Lee	lee.amber@dorsey.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List