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August 1, 2014

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-14-___

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, 2014 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, 2014

To: Service List

RE: Minnesota Energy Resources Corporation-Consolidated 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:

Amber Lee
Minnesota Energy Resources Corporation
2665 145th Street West
Rosemount, MN 55065
(651) 322-8965

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
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation for Approval of a	)	
Change in Demand Entitlement	)	Docket No. G011/M-14-___
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 Nothern 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, 2014.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
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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-14-___
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 (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, 2014.

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
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, 2014
Proposed Effective Date: November 1, 2014

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

Amber S. Lee
2665 145th Street West
Rosemount, MN 55068
(651) 322-8965

If additional information is required, please contact Amber S. Lee at (651) 322-8965, Shawn Gillespie at (402) 614-0076, or Michael J. Ahern at (612) 340-2881.

DATED: August 1, 2014

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
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation	)	
for Approval of a Change in Demand	)	Docket No. G011/M-14-___
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 - NNG (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-NNG'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, 2014.

[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 2014-2015 heating season for its MERC-Consolidated in a separate docket.

II. DISCUSSION

A. MERC's NNG Design Day Requirements

MERC's 2014-2015 NNG design day is not changing from what was filed in the November 1, 2013 filing. The design day number is still in the process of being calculated and MERC will be filing revised NNG Design Day requirements in the November 1, 2014 filing.

Table 1: MERC's Proposed NNG Reserve Margins For the 2014-2015 Heating Season

	Reserve Margin 2014-2015 Heating Season	Reserve Margin 2013-2014 Heating Season	Change
NNG Zone EF	4.27%	4.27%	0.00%

As shown in Table 1, MERC's proposed system wide reserve margin, Zone EF for the 2014-2015 heating season is positive.

For the Demand Entitlement filing effective November 1, 2014, 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, 2014, the total Design Day capacity on Northern Natural Gas (NNG), is 256,385 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 4.27% positive reserve margin.

B. <u>Forecast Methodology for MERC Demand Entitlement Nov. 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 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 was composed of <u>two service areas:</u>

1. PNG - Peoples Natural Gas
2. NMU - Northern Minnesota Utility

Which were served by <u>four pipelines:</u>

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

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 MERC 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.

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 NNG or Consolidated. 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 NNG or

Consolidated. 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.
  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.

[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.

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 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 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

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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

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. MERC's Specific PNG Proposed Northern System Demand-Related Changes

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC- 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 no change in Design Day Deliverability. Please see Table 4 for the portfolio of capacity services.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)
TF12B & TF12V	0 Mcf/Day
TF5	0 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	0 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.

On MERC's NNG contract 112561, MERC contracted for 6,000 Dth/day capacity during the winter months (November through March). The 6,000 Dth/day capacity on this contract has been rolled into MERC's NNG contract 112486 and NNG contract 112561 has been terminated. This has no impact on total contracted capacity or costs. It merely reduced the number of contracts MERC manages.

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 2014/2015 winter (November through March). MERC will be making purchases through October 2014. The Call Option contracts are projected for the entire 2014/2015 winter. Please see Attachment 8.

ii. MERC is projecting total premium costs entered into the financial Call Options on behalf of MERC's NNG firm customers amounts to $1,549,901 for the 2014/2015 winter. As of this filing, only Options through July 2014 have been purchased. These numbers will be revised to reflect actual premium costs in the November 1, 2014 filing. Please see Attachment 8.

iii. MERC will be entering into 513 contracts (10,000/contract) or 5,130,000. Total projected premium per contract is projected at $.3021. As of this filing, only Options through July 2014 have been purchased. These numbers will be revised to reflect actual premium costs in the November 1, 2014 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 176 futures contracts (10,000/contract) or 1,760,000. As of this filing, only futures contracts through July 2014 have been purchased. The numbers shouldn't change but the dates will be revised to reflect actual transaction dates in the November 1, 2014 filing. Please see Attachment 8.

vii. Please see Attachment 8.

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

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

The NNG 2014-2015 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 $4.0842. Please see Attachment 15, page 1 of 3. MERC is projecting the NNG Storage WACOG for PNG-NNG to be approximately $4.1998. 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 $4.2827, 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 $4.20 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. Since actual purchases are only through July 2014, this section will be updated in the November 1, 2014 filing.

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, 2014. 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

Based on the requirement that all interruptible and transportation customers on MERC's system must have telemetry, this has led to some customers switching from interruptible to firm. On NNG, there have been twelve (12) customers that switched from interruptible to firm service. The switching occurred between November 1, 2013 and July 1, 2014. MERC will project the impact of these customers on firm requirements by projecting their peak day volumes and provide this number in the November 1, 2014 filing.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2014. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: August 1, 2014

Respectfully Submitted,

DORSEY & WHITNEY LLP

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Resources Corporation

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2014
NNG

Design Day Requirement		245,878
Total Peak Day Entitlement		256,385
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 6)	212,806
Firm Annual Throughput - Minnesota		21,803,847
No. of Firm Customers		178,388
Department Load Factor Calculation		28.07%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2014
NNG

Pipeline Group	Nov13-Mar 14 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	Nov13-Mar 14 Avg. Customer Growth	Total *
PEAK										
NNG	178,388	178,388	100	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
Total	178,388	178,388								245,783
OFF PEAK										
NNG	178,388	178,388	55	41,361	2,341	182,893	27,735	155,158	0.60%	156,089
Total	178,388	178,388								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% confidenc
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, 2014

NNG

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
14/15	178,388	245,878	1.38
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

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2015

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	5,975,516	15,812,613	21,788,129
SVI	1,408,810	1,257,722	2,666,533
SVJ	6,017	9,702	15,718
LVI			0
LVJ	0	0	0
SLV	0	0	0
Total	7,390,343	17,080,037	24,470,380

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2014

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
TF-12 Base & Variable	76,079	0	76,079
TF5	31,515	0	31,515
TFX - 12	32,297	0	32,297
TFX - 5	93,084	0	93,084
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	20,000	0	20,000
Heating Season Total	**256,385**	**0**	**256,385**
Non-Heating Season Total	113,786	0	113,786
Heating Season Forecasted Design Day-Adjusted	245,878	0	245,878
Non-Heating Season Forecasted Design Day	156,089	(0)	156,089
Heating Season Capacity Surplus/Shortage	10,507	0	10,507
Non-Heating Season Capacity Surplus/Shortage	(42,303)	0	(42,303)

*Not included in Heating Season Total entitlement

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2014
NNG

All costs in $/Dth	Last Base Cost of Gas G011/ MR13-732* Jan. 14	Last Demand Change G011-12-1193 Jul. 13	Last Demand Change G011-13-670 Nov. 13	Most Recent PGA Aug. 14	Current Proposal Effective Nov.1,2014	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:		**93**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$1.7955	$1.6968	$1.7177	$1.7822	$1.7920	($0.0035)	$0.0743	0.55%	$0.0098
Commodity Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	$0.0000	$0.2536	0.00%	$0.0000
Total Cost of Gas	$8.5880	$7.5547	$7.7406	$8.0562	$8.0779	($0.5101)	$0.3373	0.27%	$0.0217
Avg Annual Cost	$798.68	$702.59	$719.88	$749.23	$751.24	($47.44)	$31.37	0.27%	$2.02
Effect of proposed commodity change on average annual bills:									$1.11
Effect of proposed demand change on average annual bills:									$0.91
2) Small Vol. Interruptible: Avg. Annual Use:		**6,699**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost									
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	($0.5066)	$0.1461	0.23%	$0.0119
Avg Annual Cost	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$35,225.35	($3,393.71)	$978.72	0.23%	$79.72
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**42,000**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost									
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	($0.5066)	$0.0552	0.27%	$0.0119
Avg Annual Cost	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$187,299.00	($21,277.20)	$2,318.40	0.27%	$499.80
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**6,699**		**Dth**					
		25		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	$0.1663	$0.1663	0.82%	$0.1548
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	($0.5066)	$0.1461	0.23%	$0.0119
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	$0.1663	$0.4616	0.72%	$0.1548
Avg Annual Cost	$39,155.94	$33,684.14	$34,776.12	$35,682.79	$35,766.38	($3,389.56)	$990.26	0.23%	$83.59
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$3.87
5) Large Vol. Firm: Avg. Annual Use:		**42,000**		**Dth**					
		75		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	$0.1663	$0.1663	0.82%	$0.1548
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	($0.5066)	$0.0552	0.27%	$0.0119
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	$0.1663	$0.4616	0.72%	$0.1548
Avg Annual Cost	$210,186.82	$179,679.15	$186,569.07	$188,410.68	$188,922.09	($3,389.56)	$2,353.02	0.27%	$511.41
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$11.61

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-13-600
*As approved in Docket No. G011/MR-13-732; to coincide with implementation of interim rates in Docket No. G011/GR-13-617

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2014

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE — 01-Nov-14

		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	112495	$5.6830	$10.2300	$7.5171	$0.0000	$7.5171
TF-12B Discount	112495	$5.6830	$10.0320	$7.4951	$0.0000	$7.4951
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						$3.9655

V. ANNUAL SALES -- As approved in Docket No. G011/MR-13-732

Total MERC NNG Annual Sales — 234,442,025 Therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-14

		Contract #(s)	Monthly Entitlement (Dth)	Months	Rate $/Dth		Contract Costs	Rate/Therm
A. GS	TF12B (Max Rate) Winter	112495	43,953	5	$10.2300	=	$2,248,196	$0.01046
	TF12B (Max Rate) Summe	112495	43,190	7	$5.6830	=	$1,718,141	$0.00799
	TF12V (Max Rate)	112495	26,926	12	$9.0926	=	$2,937,928	$0.01366
	TF5 (Max Rate)	112495	31,515	5	$15.1530	=	$2,387,734	$0.01110
	TF12B (Discount-Winter)	112495	5,200	12	$7.4951	=	$467,694	$0.00218
	TFX5 (Discount)	112561	0	5	$4.5600	=	$0	$0.00000
	TFX12 (Max Rate)	112486	10,822	12	$9.6288	=	$1,250,434	$0.00582
	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	66,271	5	$15.1530	=	$5,021,022	$0.02335
	TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00032
	TFX12 (Discount)	111866	1,283	12	$4.8640	=	$74,886	$0.00035
	TFX12 (Discount)	111866	8,271	12	$5.4720	=	$543,107	$0.00253
	TFX12 (Discount)	111866	11,921	12	$7.6025	=	$1,087,553	$0.00506
	TFX5 (Discount)	111866	379	5	$4.8640	=	$9,217	$0.00004
	TFX5 (Discount)	111866	2,445	5	$5.4720	=	$66,895	$0.00031
	TFX5 (Discount)	111866	22,189	5	$15.1392	=	$1,679,619	$0.00781
	Bison	FT0003	50,000	12	$17.4896	=	$10,493,750	$0.04880
	NBPL	T8673F	50,000	12	$6.9958	=	$4,197,500	$0.01952
	Windom		2,500	12	$0.0000	=	$0	$0.00000
	Ortonville		910	12	$8.0000	=	$87,360	$0.00041
	NNG Zone GDD Call Option		20,000	3	$0.9000	=	$54,000	$0.00025
FDD:	Storage Reservation	118657	75,437	12	$1.7140	=	$1,551,588	$0.00722
	Storage Cycle Volume	118657	869,864	5	$0.3567	=	$1,551,402	$0.00722
	Storage Reservation	118657	5,550	12	$3.3157	=	$220,826	$0.00103
	Storage Cycle Volume	118657	64,000	5	$0.6901	=	$220,832	$0.00103
	Storage Reservation	125915	2,602	12	$1.7140	=	$53,518	$0.00025
	Storage Cycle Volume	125915	30,000	5	$0.3567	=	$53,505	$0.00025
	Storage Reservation	125916	11,274	12	$1.7140	=	$231,884	$0.00108
	Storage Cycle Volume	125916	130,000	5	$0.3567	=	$231,855	$0.00108
	Total Demand Cost						$38,531,579	$0.17705
	Rate Case volume as approved in Docket No. G0011/MR-13-732 in therms						215,014,955	
	NNG-GS Demand Current Cost of Gas/therm							**$0.17920**
	NNG-GS Commodity Current Cost of Gas/therm+							**$0.40569**
	Total NNG-GS Current Cost of Gas/therm							**$0.58489**

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	23,444,203	x	$3.9655	$92,967,985.01	234,442,025	$0.39655
SMS-Bal Service	272,160	x	$2.1800	$593,309	234,442,025	$0.00253
Call Option Premium				$ 1,549,901	234,442,025	$0.00661
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$ 95,111,195	234,442,025	$0.40569

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2014

NNG

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Months	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate) Winter	43,953	112495	5	$10.2300	=	$2,248,196	$0.11113
TF12B (Max Rate) Summer	43,190	112495	7	$5.6830	=	$1,718,141	$0.08493
TF12V (Max Rate)	26,926	112495	12	$9.0926	=	$2,937,928	$0.14522
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.11802
TF12B (Discount-Winter)	5,200	112495	12	$7.4951	=	$467,694	$0.02312
TFX5 (Discount)	0	112561	5	$4.5600	=	$0	$0.00000
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06181
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)	66,271	112486	5	$15.1530	=	$5,021,022	$0.24819
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00338
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00370
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02685
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05376
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00046
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00331
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08302
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.51870
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	$0.20748
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00432
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00267
Storage Reservation	75,437	118657	12	$1.7140	=	$1,551,588	$0.07669
Storage Cycle Volume	869,864	118657	5	$0.3567	=	$1,551,402	$0.07668
Storage Reservation	5,550	118657	12	$3.3157	=	$220,826	$0.01092
Storage Cycle Volume	64,000	118657	5	$0.6901	=	$220,832	$0.01092
Storage Reservation	2,602	125915	12	$1.7140	=	$53,518	$0.00265
Storage Cycle Volume	30,000	125915	5	$0.3567	=	$53,505	$0.00264
Storage Reservation	11,274	125916	12	$1.7140	=	$231,884	$0.01146
Storage Cycle Volume	130,000	125916	5	$0.3567	=	$231,855	$0.01146
				TOTAL		$38,531,578	
				Annualized Entitlement		20,230,860	
				Demand Component		$1.90459	$1.90459

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, 2014
NNG

All costs in $/Dth	Last Base Cost of Gas G011/ MR13-732* Jan. 14	Last Demand Change G011- 12-1193 Jul. 13	Last Demand Change G011- 13-977 Nov. 13	Most Recent PGA Aug. 14	Current Proposal Effective Nov.1,2014	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. Annua		**93**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$1.7955	$1.6968	$1.7177	$1.7822	$1.6006	($0.1949)	($0.1171)	-10.19%	($0.1816)
Commodity Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	$0.0000	$0.2536	0.00%	$0.0000
Total Cost of Gas	$8.5880	$7.5547	$7.7406	$8.0562	$8.0621	($0.5259)	$0.3215	0.07%	$0.0059
Avg Annual Cost	$798.68	$702.59	$719.88	$749.23	$749.78	($48.91)	$29.90	0.07%	$0.55
Effect of proposed commodity change on average annual bills:									$17.43
Effect of proposed demand change on average annual bills:									($16.89)
2) Small Vol. Interruptible: Avg. Annual Use		**6,699**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost									
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	($0.3310)	$0.3217	3.57%	$0.1875
Avg Annual Cost	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$36,401.42	($2,217.65)	$2,154.79	3.57%	$1,255.78
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**42,000**		**Dth**		0			
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost									
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	($0.3310)	$0.2308	4.21%	$0.1875
Avg Annual Cost	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$194,672.44	($13,903.76)	$9,691.84	4.21%	$7,873.24
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**6,699**		**Dth**					
		25		**DTh**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	$0.0000	($1.3265)	-7.08%	($1.3380)
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$2.5953	$0.2953	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	($0.3310)	$0.3217	3.57%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	($1.3265)	($1.0312)	-6.23%	($1.3380)
Avg Annual Cost	$39,155.94	$33,684.14	$34,776.12	$35,682.79	$36,905.13	($2,250.81)	$2,129.01	3.43%	$1,222.33
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									($33.45)
5) Large Vol. Firm: Avg. Annual Use:		**42,000**		**Dth**					
		75		**DTh**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	($1.3265)	($1.3265)	-7.08%	($1.3380)
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	($0.3310)	$0.2308	4.21%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	$20.1484	($1.0312)	-6.23%	($1.3380)
Avg Annual Cost	$210,186.82	$179,679.15	$186,569.07	$188,410.68	$196,183.57	($1,713.94)	$9,614.50	4.13%	$7,772.89
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									($100.35)

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-13-600
*As approved in Docket No. G011/MR-13-732; to coincide with implementation of interim rates in Docket No. G011/GR-13-617

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, 2014
NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-14**

		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	112495	5.683	10.23	$7.5776	$0.0000	$7.5776
TF-12B Discount	112495	5.683	10.032	$7.4951	$0.0000	$7.4951
TF-12V	112495	5.683	13.866	$9.0926	$0.0000	$9.0926
TF-5	112495	0	15.153	$6.3138	$0.0000	$6.3138
TFX	112486	5.683	15.153	$9.6288	$0.0000	$9.6288
TFX-5	112486	0	15.153	$6.3138	$0.0000	$6.3138
TFX-5 Discount	112486	0	7.6	$3.1667	$0.0000	$3.1667
TFX - Discount	111866	7.6025	0	$4.4348	$0.0000	$4.4348
TFX - Discount	111866	15.1392	0	$8.8312	$0.0000	$8.8312
TFX - Discount	111866	5.472	5.472	$5.4720	$0.0000	$5.4720
TFX - Discount	111866	4.864	4.864	$4.8640	$0.0000	$4.8640
Gas Cost						$3.9655

V. ANNUAL SALES -- As approved in Docket No. G011/MR-13-732 234,442,025

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-14**

		Contract #(s)		Months				Rate/CCF
A. GS	TF12B (Max Rate) Winter	112,495	43,953	5	10	=	$2,248,196	$0.01046
	TF12B (Max Rate) Summe	112,495	43,190	7	6	=	$1,718,141	$0.00799
	TF12V (Max Rate)	112,495	26,926	12	9	=	$2,937,928	$0.01366
	TF5 (Max Rate)	112,495	31,515	5	15	=	$2,387,734	$0.01110
	TF12B (Discount-Winter)	112,495	5,200	12	7	=	$467,694	$0.00218
	TFX5 (Discount)	112,561	0	5	5	=	$0	$0.00000
	TFX12 (Max Rate)	112,486	10,822	12	10	=	$1,250,434	$0.00582
	TFX Apr (Max Rate)	112,486	2,000	1	6	=	$11,366	$0.00005
	TFX Oct (Max Rate)	112,486	2,000	1	6	=	$11,366	$0.00005
	TFX5 (Max Rate)	112,486	66,271	5	15	=	$5,021,022	$0.02335
	TFX5 (Discount)	112,486	1,800	5	8	=	$68,400	$0.00032
	TFX12 (Discount)	111,866	1,283	12	5	=	$74,886	$0.00035
	TFX12 (Discount)	111,866	8,271	12	5	=	$543,107	$0.00253
	TFX12 (Discount)	111,866	11,921	12	8	=	$1,087,553	$0.00506
	TFX5 (Discount)	111,866	379	5	5	=	$9,217	$0.00004
	TFX5 (Discount)	111,866	2,445	5	5	=	$66,895	$0.00031
	TFX5 (Discount)	111,866	22,189	5	15	=	$1,679,619	$0.00781
	Bison	FT0003	50,000	12	17	=	$10,493,750	$0.04880
	NBPL	T8673F	50,000	12	7	=	$4,197,500	$0.01952
	Windom	0	2,500	12	0	=	$0	$0.00000
	Ortonville	0	910	12	8	=	$87,360	$0.00041
	NNG Zone GDD Call Optic	0	20,000	3	1	=	$54,000	$0.00025
	Total Demand Cost						$34,416,168	**$0.16006**
	Rate Case volume as approved in Docket No. G0011/MR-13-732 in therms						215,014,955	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.16006**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.42325**
	Total GS-1 Current Cost of Gas/Ccf							**$0.58331**

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	2	=	$1,551,588	$0.00662
	FDD - Storage Cycle	118657	869,864	5	0	=	$1,551,402	$0.00662
	FDD - Reservation	118657	5,550	12	3	=	$220,826	$0.00094
	FDD - Storage Cycle	118657	64,000	5	1	=	$220,832	$0.00094
	FDD - Reservation	125915	2,602	12	2	=	$53,518	$0.00023
	FDD - Storage Cycle	125915	30,000	5	0	=	$53,505	$0.00023
	FDD - Reservation	125916	11,274	12	2	=	$231,884	$0.00099
	FDD - Storage Cycle	125916	130,000	5	0	=	$231,855	$0.00099
	Firm Deferred Delivery Storage Contracts						$4,115,410	$0.01755

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	23,444,203	x	$3.9655	$92,967,985	234,442,025	$0.39655
SMS-Bal Service	272,160	x	$2.1800	$593,309	234,442,025	$0.00253
Call Option Premium				$1,549,901	234,442,025	$0.00661
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$99,226,605	234,442,025	**$0.42325**

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, 2014

NNG

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate) Winter	43,953	112495	5	$10.2300	=	$2,248,196	$0.11466
TF12B (Max Rate) Summer	43,190	112495	7	$5.6830	=	$1,718,141	$0.08763
TF12V (Max Rate)	26,926	112495	12	$9.0926	=	$2,937,928	$0.14984
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.12178
TF12B (Discount-Winter)	5,200	112495	12	$7.4951	=	$467,694	$0.02385
TFX5 (Discount)	0	112561	5	$4.5600	=	$0	$0.00000
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06378
TFX Apr (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00058
TFX Oct (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00058
TFX5 (Max Rate)	66,271	112486	5	$15.1530	=	$5,021,022	$0.25608
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00349
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00382
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02770
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05547
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00047
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00341
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08566
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.53521
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	$0.21408
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00446
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00275
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	2,602	125915	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	30,000	125915	0	$0.3567	=	$0	$0.00000
Storage Reservation	11,274	125916	0	$1.7140	=	$0	$0.00000
				TOTAL		$34,416,169	
				Annualized Entitlement		19,606,860	
				Demand Component		$1.75531	$1.75531

Attachment 5

MINNESOTA ENERGY RESOURCES - NNG

NNG Entitlement Allocation

Heating Season 2014-2015

		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**	**235,475**	**235,475**
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)**
		231,970	**231,970**
	Direct Assigned Entitlement		
11	**TF12B (112495)**	49,153	**49,153**
12	**TF12V (112495)**	26,926	**26,926**
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)**	68,071	**68,071**
18	**TFX12 (111866)**	21,475	**21,475**
19	**TFX5 (111866)**	25,013	**25,013**
20	**TFX5 (112561)**	0	**-**
21	**Bison (FT 0003) ***	50,000	**50,000**
22	**NBPL (T6873F) ***	50,000	**50,000**
23	**Total Winter Allocated Entitlement**	232,975	**232,975**
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**	**256,385**	**256,385**
29	**Contract Demand**		
30	**Total Design Day Capacity**	**256,385**	**256,385**
			100.00%
31	**Storage**		
32	**Storage MSQ - 118657**	4,669,321	**4,669,321**
33	**Storage MSQ -125915**	150,000	**150,000**
34	**Storage MSQ - 125916**	650,000	**650,000**
35	**SMS**	22,680	**22,680**
36	**Total Entitlement**	256,385	**256,385**
37	**Design Day**	245,878	**245,878**
38	**Reserve Margin**	10,507	**10,507**
		4.27%	4.27%

***** 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

2014-2015

State	1/20 Design DDD	13/14 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	178,388	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
TOTAL	**100**	**178,388**	**41,361**	**2,341**	**287,358**	**43,041**	**244,317**		**245,783**

Attachment 7

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2014-2015 VS. 2013-2014

	2014-2015 Proposed		2013-2014		Difference	
	NNG	NNG	NNG	NNG		
	Winter	Total	Winter	Total	Winter	Total
TF12(base)	49,153	49,153	49,153	49,153	-	-
TF12(variable)	26,926	26,926	26,926	26,926	-	-
TF12	76,079	76,079	76,079	76,079	-	-
Peak Capacity	-	-	-	-	-	-
TF5	31,515	31,515	31,515	31,515	-	-
TF Total	107,594	107,594	107,594	107,594	-	-
TFX12	32,297	32,297	32,297	32,297	-	-
TFX5	93,084	93,084	93,084	93,084	-	-
TFX Total	125,381	125,381	125,381	125,381	-	-
NNG Total	232,975	232,975	232,975	232,975	-	-
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	256,385	256,385	256,385	256,385	-	-

	NNG-Total EF
Design Day	245,878
Capacity	256,385
Reserve Margin	10,507
	4.27%

Attachment 8

MINNESOTA ENERGY RESOURCES - NNG

Financial Options

Heating Season 2014-2015

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	$16,800			$ 0	$ 54,000

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	06/25/14	2,718	06/16/14	114	06/11/14	224	06/30/14	1,272	06/20/14	1,243	5,572	166,187
2	07/25/14	2,966	06/16/14	228	06/11/14	1,567	07/30/14	1,484	06/20/14	1,243	7,488	224,700
3	08/xx/14	2,966	07/16/14	455	07/10/14	448	8/xx/2014	1,484	06/20/14	1,243	6,596	197,065
4	09/xx14	2,966	8/xx/2014	455	07/10/14	2,014	9/xx/2014	1,272	06/20/14	1,243	7,951	239,699
5	10/xx14	2,718	9/xx/2014	342	8/xx/2014	2,238	10/xx/2014	1,272	07/21/14	4,973	11,544	351,319
6			10/xx/2014	342	9/xx/2014	2,238			8/xx/2014	4,724	7,304	226,434
7					10/xx/2014	2,238			9/xx/2014	4,724	6,963	215,846
8									10/xx/2014	4,476	4,476	138,750
9											-	-
10											-	-
Total		14,333		1,935		10,968		6,786		23,871	57,893	1,760,000
		430,000		60,000		340,000		190,000		740,000		1,760,000
		580,000		170,000		490,000		320,000		960,000		2,520,000

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	06/13/14	4,584	06/27/14	6,452	06/23/14	7,867	06/18/14	8,156	06/10/14	5,935	32,994	993,768
2	07/14/14	4,584	07/28/14	6,710	07/24/14	8,129	07/18/14	8,156	07/08/14	6,194	33,773	1,017,897
3	8/xx/2014	4,584	08/14/14	6,710	8/xx/2014	8,129	8/xx/2014	8,156	8/xx/2014	6,194	33,773	1,017,897
4	9/xx/2014	5,124	9/xx/2014	6,710	9/xx/2014	8,129	9/xx/2014	8,156	9/xx/2014	6,194	34,312	1,034,077
5	10/xx/2014	5,124	10/xx/2014	6,968	10/xx/2014	8,391	10/xx/2014	8,447	10/xx/2014	6,452	35,382	1,066,362
6												
7												
Total		24,000		33,548		40,645		41,071		30,968	170,233	5,130,000
		720,000		1,040,000		1,260,000		1,150,000		960,000		5,130,000
		890,000		1,300,000		1,550,000		1,410,000		1,200,000		6,350,000

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	$ 0.2380	$ 32,732	$ 0.2380	$47,600	$ 0.3450	$84,135	$ 0.3750	$85,638	$ 0.3960	$ 72,864	$ 0.3250	$ 322,969
2	$ 0.2220	$ 30,531	$ 0.2230	$46,384	$ 0.2370	$59,724	$ 0.3050	$69,652	$ 0.4110	$ 78,912	$ 0.2802	$ 285,204
3	$ 0.2300	$ 31,631	$ 0.2305	$47,944	$ 0.2910	$73,332	$ 0.3400	$77,645	$ 0.4035	$ 77,472	$ 0.3026	$ 308,025
4	$ 0.2300	$ 35,353	$ 0.2305	$47,944	$ 0.2910	$73,332	$ 0.3400	$77,645	$ 0.4035	$ 77,472	$ 0.3026	$ 311,746
5	$ 0.2300	$ 35,353	$ 0.2305	$49,788	$ 0.2910	$75,698	$ 0.3400	$80,418	$ 0.4035	$ 80,700	$ 0.3026	$ 321,957
6												
7												
Total	**$ 0.2300**	**$ 165,600**	**$ 0.2304**	**$ 239,660**	**$ 0.2907**	**$ 366,221**	**$ 0.3400**	**$ 391,000**	**$ 0.4036**	**$ 387,420**	**$ 0.3021**	**$ 1,549,901**
		$ 204,700		**$ 299,575**		**$ 450,510**		**$ 479,400**		**$ 484,275**		**$ 1,918,460**

Units - Collar Floor (put)

No Puts were purchased.

14/15 Winter Portfolio Plan - MERC NNG Consolidated Hedging Plan

10,000 Contract Size

REVISED: 7/1/2014

System	Purchase Month	Nov-14 Number Contracts	Nov-14 Contract Volume	Dec-14 Number Contracts	Dec-14 Contract Volume	Jan-15 Number Contracts	Jan-15 Contract Volume	Feb-15 Number Contracts	Feb-15 Contract Volume	Mar-15 Number Contracts	Mar-15 Contract Volume	Total Number Contracts	Total Contract Volume	Percent of Requirements
MN Requirements			2,404,840		3,483,485		4,187,889		3,826,379		3,177,443		17,080,036	17,080,036
NNG -MN			80,161		112,370		135,093		136,656		102,498		113,113	
70%			1,683,388		2,438,440		2,931,522		2,678,465		2,224,210		11,956,025	
40%			961,936		1,393,394		1,675,156		1,530,552		1,270,977		6,832,014	
			533,259		1,339,984		1,339,984		1,339,984		533,259		5,086,470	
			428,677		53,410		335,172		190,568		737,718		1,745,544	
30%			721,452	0	1,045,046	0	1,256,367	0	1,147,914	0	953,233		5,124,011	
Contracts	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	May-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	8	80,000	0	0	5	50,000	3	30,000	15	150,000	31	310,000	
	Jul-14	9	90,000	2	20,000	8	80,000	4	40,000	15	150,000	38	380,000	
	Aug-14	9	90,000	2	20,000	7	70,000	4	40,000	15	150,000	37	370,000	
	Sep-14	9	90,000	1	10,000	7	70,000	4	40,000	15	150,000	36	360,000	
	Oct-14	8	80,000	1	10,000	7	70,000	4	40,000	14	140,000	34	340,000	
	Total	**43**	**430,000**	**6**	**60,000**	**34**	**340,000**	**19**	**190,000**	**74**	**740,000**	**176**	**1,760,000**	**10.30%**
Call Options	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	May-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	14	140,000	20	200,000	25	250,000	23	230,000	19	190,000	101	1,010,000	
	Jul-14	14	140,000	21	210,000	25	250,000	23	230,000	19	190,000	102	1,020,000	
	Aug-14	14	140,000	21	210,000	25	250,000	23	230,000	19	190,000	102	1,020,000	
	Sep-14	15	150,000	21	210,000	25	250,000	23	230,000	19	190,000	103	1,030,000	
	Oct-14	15	150,000	21	210,000	26	260,000	23	230,000	20	200,000	105	1,050,000	
	Total	**72**	**720,000**	**104**	**1,040,000**	**126**	**1,260,000**	**115**	**1,150,000**	**96**	**960,000**	**513**	**5,130,000**	**30.04%**
Collars	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-14	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-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-14	9,584	287,520	8,871	275,001	12,904	400,024	11,965	335,020	13,709	424,979	57,033	1,722,544	
	Aug-14	9,584	287,520	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,032	1,722,516	
	Sep-14	9,583	287,490	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,031	1,722,486	
	Oct-14	9,583	287,490	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,031	1,722,486	
	Total		**1,150,020**		**1,100,004**		**1,600,003**		**1,339,996**		**1,700,009**		**6,890,032**	**40.34%**
Physical Hedges			**0**		**0**		**0**		**0**		**0**		**0**	
Storage			533,259		1,339,984		1,339,984		1,339,984		533,259		5,086,470	**29.78%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			70.00%		70.04%		70.20%		70.04%		70.29%		70.12%	
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													1,760,000	**10.30%**
Call Options													5,130,000	**30.04%**
Costing Collar													0	**0.00%**
Storage													5,086,470	**29.78%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													5,103,566	**29.88%**
Total													17,080,036	**100.00%**

NOTE:

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN

NOVEMBER, 2014 THROUGH MARCH, 2015

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov (Daily Volumes)	Dec (Daily Volumes)	Jan (Daily Volumes)	Feb (Daily Volumes)	Mar (Daily Volumes)	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	TBD	NNG Ventura	590	-	13,869	10,113	17,095	1,260,748
Index - Back Financial Options	2946	1/11/2011	NNG Welcome	8,957	8,957	8,957	8,957	8,957	1,352,507
Index - Back Financial Options	TBD	TBD	NNG Welcome	7,740	5,480	7,740	7,740	7,740	1,098,680
Index - Back Financial Options	2946	1/11/2011	NNG Aberdeen	3,244	3,244	3,244	3,244	3,244	489,844
Index - Back Financial Options	TBD	TBD	NNG Beatrice	5,623	5,623	5,623	5,623	5,623	849,073
Index - Back Financial Options	2946	1/11/2011	NNG Marshall	12,180	12,180	12,180	12,180	12,180	1,839,180
	Total Actual Seasonal Index			**38,334**	**35,484**	**51,613**	**47,857**	**54,839**	**6,890,032**

GAS DAILY PACKAGES				Nov	Dec	Jan	Feb	Mar	Total
	TBD	TBD	MERC Zone EF	-	20,000	20,000	20,000	-	60,000

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 125915 Volume Injected	Contract # 125916 Volume Injected	Total Volume Injected
May - balance forward	79,831	0	0	79,831
June	817,150	29,760	127,770	974,680
July	964,644	30,044	131,380	1,126,068
August	946,071	30,392	131,700	1,108,163
Sept	915,553	29,412	127,451	1,072,416
Oct (est)	946,072	30,392	131,699	1,108,163
Total	**4,669,321**	**150,000**	**650,000**	**5,469,321**

MERC Attachment 10
NNG Demand Entitlements

MINNESOTA ENERGY RESOURCES - NNG

	M-10-Peoples Mn GS	M-11-Peoples Mn GS	M-12-Peoples Mn GS	**M-13-Peoples Mn GS**	**M-14-Peoples Mn GS**	Proposed Change
Design Day	194,598	211,182	200,785	**245,878**	**245,878**	0
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	35.92%	33.31%	38.29%	**28.43%**	**28.07%**	0.36%
Total Design Day Capacity (includes non-recallable capacity)	233,627	221,436	208,007	**256,385**	**256,385**	0
Less: Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
Less: Northwestern Energy	0	910	910	**910**	**910**	0
Less: LS Power	25,951	0	0	**0**	**0**	0
Less: TF12B	0	0	0	**0**	**0**	0
Less: TF5						
Less: TFX(5)						
Total Design Day Capacity	205,176	218,026	204,597	**252,975**	**252,975**	48,378
Factors for All Winter Capacity	100.00%	100.00%	100.00%	**100.00%**	**100.00%**	
Allocated Entitlements in PGA						
TF12B	34,875	42,396	41,156			0
TF12V	32,290	25,298	25,820			0
TF5	28,785	29,011	28,704			0
TFX12	28,802	29,029	28,721			0
TFX(5)	80,424	81,057	80,197			0
TFX(5) (12-V)	0	0	0			0
TFX (October Only)	1,784	1,798	1,779			0
TFX (April Only)	1,784	1,798	1,779			0
NNG Zone Delivery Call Option	0	11,235	0			0
LS Power	25,951	0	0			0
Bison *	44,589	44,940	44,463			0
NBPL *	44,589	44,940	44,463			0
Peak Capacity	231,127	218,026	205,508			0
Total Allocated Entitlements in PGA	323,873	311,502	297,082	0	0	0

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

	M-10-Peoples Mn GS	M-11-Peoples Mn GS	M-12-Peoples Mn GS	**M-13-Peoples Mn GS**	**M-14-Peoples Mn GS**	Proposed Change
Direct Assigned Entitlements in PGA						
TF12B				**49,153**	**49,153**	**0**
TF12V				**26,926**	**26,926**	**0**
TF5				**31,515**	**31,515**	**0**
TFX12				**32,297**	**32,297**	**0**
TFX(5)				**93,084**	**93,084**	**0**
TFX(5) (12-V)						**0**
TFX (October Only)				**2,000**	**2,000**	**0**
TFX (April Only)				**2,000**	**2,000**	**0**
Windom	2,500	2,500	2,500	**2,500**	**2,500**	**0**
Northwestern Energy	0	910	910	**910**	**910**	**0**
NNG Zone Delivery Call Option				**20,000**	**20,000**	**0**
LS Power	0	0	0	**0**	**0**	**0**
Bison *				**50,000**	**50,000**	**0**
NBPL *				**50,000**	**50,000**	**0**
TFX (October Only)	0	0	0	**0**	**0**	**0**
TFX (April Only)	0	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	2,500	3,410	3,410	**256,385**	**256,385**	**0**
Total Capacity before Peak Shaving	233,627	221,436	208,918	**256,385**	**256,385**	**0**
LP Peak Shaving	0	0				**0**
Total Design Day Capacity	233,627	221,436	208,918	**256,385**	**256,385**	**0**
Total Transp. (with TFX Offpeak less LSP)	207,676	221,436	208,918	**256,385**	**256,385**	**0**
Total Annual Transportation	98,467	100,133	99,107	**111,786**	**111,786**	**0**
Total Seasonal Transportation	135,160	110,068	108,901	**144,599**	**144,599**	**0**
Total Percent Seasonal	57.9%	49.7%	52.1%	**56.4%**	**56.4%**	**0.0%**
LS Power as % of Total DD Capacity	11.1%	0.0%	0.0%	**0.0%**	**0.0%**	**0.0%**
Reserve Margin	20.06%	4.86%	4.05%	**4.27%**	**4.27%**	**0.0%**
Direct Assigned Demand Not in PGA						
TF-12-B Contract Demand	0	0	0	**0**	**0**	0
Total Design Day Capacity w/ contract demand	233,627	221,436	208,007	**256,385**	**256,385**	0
Factors	35.92%	33.31%	38.29%	**28.43%**	**28.07%**	0.36%
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	1,784	1,798	1,779	**2,000**	**2,000**	0
TFX Apr	1,784	1,798	1,779	**2,000**	**2,000**	0
TFX Apr-Oct	0	0	0	**0**	**0**	0
TFX May-Sept	0	0	0	**0**	**0**	0
FDD Storage reservation	78,409	84,483	86,671	**97,463**	**94,863**	2,600
FDD Storage capacity	4,520,719	4,870,885	4,997,056	**5,619,321**	**5,469,321**	150,000
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	20,226	20,385	20,168	**22,680**	**22,680**	0
SBA	0	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - NNG

Rate Impacts
NNG

1) General Service Residential: Avg. Annual Use: 93 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$1.7955	$1.6968	$1.7177	$1.7822	$1.7920	-0.19%	4.33%	0.55%	$0.0098
Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$8.5880	$7.5547	$7.7406	$8.0562	$8.0779	-5.94%	4.36%	0.27%	$0.0217
Avg. Annual Bill*	$798.68	$702.59	$719.88	$749.23	$751.24	-5.94%	4.36%	0.27%	$2.02
Effect of proposed commodity change on average annual bills:									$1.11
Effect of proposed demand change on average annual bills:									$0.91

2) Small Volume Interruptible: Avg. Annual Use: 6,699 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate									$0.0000
Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	-8.79%	2.86%	0.23%	$0.0119
Avg. Annual Bill*	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$35,225.35	-8.79%	2.86%	0.23%	$79.72
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 42,000 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate									$0.0000
Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	-10.20%	1.25%	0.27%	$0.0119
Avg. Annual Bill*	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$187,299.00	-10.20%	1.25%	0.27%	$499.80
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 6,699 Dth
Avg. Annual CD Volumes: 25 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	0.88%	0.88%	0.82%	$0.1548
Comm. Margin	$1.2014	$1.2781	$1.0647	$1.0647	$1.2014	0.00%	12.84%	12.84%	$0.1367
SV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$5.7649	$5.1606	$5.1122	$5.1097	$5.2583	-8.79%	2.86%	2.91%	$0.1486
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	0.77%	2.18%	0.72%	$0.1548
Avg. Annual Bill*	$39,155.94	$35,113.71	$34,776.12	$34,767.04	$35,766.38	-8.66%	2.85%	2.87%	$999.34
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$3.87

5) Large Volume Firm: Avg. Annual Use: 42,000 Dth
Avg. Annual CD Units: 75 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$18.8796	$19.3628	$19.3628	$19.4140	$19.0459	0.88%	-1.64%	-1.90%	($0.3681)
Comm. Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
LV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	-10.20%	1.25%	0.27%	$0.0119
Total Demand Cost	$21.4749	$21.6628	$21.6628	$22.0093	$21.6412	0.77%	-0.10%	-1.67%	($0.3681)
Avg. Annual Bill*	$210,186.82	$179,675.31	$186,605.31	$188,449.90	$188,922.09	-10.12%	1.24%	0.25%	$472.19
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									-$27.61

***** Average Annual Bill amount does not include customer charges.

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	$0.0119	0.29%	1.19%	$0.0098	0.55%	0.0217		0.27%
Sm Vol Inter. Service	$0.0119	0.29%	1.19%	$0.0000	0.00%	0.0119		0.23%
Lrg Vol Inter. Service	$0.0119	0.29%	1.19%	$0.0000	0.00%	0.0119		0.27%
Sm Vol Joint Service	$0.0119	0.29%	1.19%	$0.1548	0.82%	0.1486	***	2.91%
Lrg Vol Joint Service	$0.0119	0.29%	1.19%	($0.3681)	-1.90%	0.0119	***	0.27%

*** 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: 93 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$1.7955	$1.6968	$1.7177	$1.7822	$1.6006	-10.85%	-6.81%	-10.19%	($0.1816)
Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$8.5880	$7.5547	$7.7406	$8.0562	$8.0621	-6.12%	4.15%	0.07%	$0.0059
Avg. Annual Bill*	$798.68	$702.59	$719.88	$749.23	$749.78	-6.12%	4.15%	0.07%	$0.55
Effect of proposed commodity change on average annual bills:									$17.43
Effect of proposed demand change on average annual bills:									($16.89)

2) Small Volume Interruptible: Avg. Annual Use: 6,699 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate									
Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	-5.74%	6.29%	3.57%	$0.1875
Avg. Annual Bill*	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$36,401.42	-5.74%	6.29%	3.57%	$1,255.78
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 42,000 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate									
Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	-6.67%	5.24%	4.21%	$0.1875
Avg. Annual Bill*	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$194,672.44	-6.67%	5.24%	4.21%	$7,873.24
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 6,699 Dth
Avg. Annual CD Volumes: 25 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	-7.03%	-7.03%	-7.08%	($1.3380)
Comm. Margin	$1.2014	$1.0647	$1.0647	$1.0647	$1.0647	-11.38%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$5.7649	$4.9472	$5.1122	$5.1097	$5.2972	-8.11%	3.62%	3.67%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	-6.18%	-4.87%	-6.23%	($1.3380)
Avg. Annual Bill*	$39,155.94	$33,684.14	$34,776.12	$34,767.04	$35,989.37	-8.09%	3.49%	3.52%	$1,222.33
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									($33.45)

5) Large Volume Firm: Avg. Annual Use: 42,000 Dth
Avg. Annual CD Units: 75 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$18.8796	$19.4140	$18.8796	$19.4140	$17.5531	-7.03%	-7.03%	-9.59%	($1.8609)
Comm. Margin	$0.4026	$0.3568	$0.3568	$0.3568	$0.3568	-11.38%	0.00%	0.00%	$0.0000
LV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$4.9661	$4.2393	$4.4043	$4.4018	$4.5893	-7.59%	4.20%	4.26%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$22.0093	$20.1484	-6.18%	-4.87%	-8.45%	($1.8609)
Avg. Annual Bill*	$210,186.82	$179,679.15	$186,569.07	$186,526.30	$194,259.97	-7.58%	4.12%	4.15%	$7,733.67
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									($139.57)

***** Average Annual Bill amount does not include customer charges.

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	$0.1875	4.63%	18.75%	($0.1816)	-10.19%	0.0059		0.07%
Sm Vol Inter. Service	$0.1875	4.63%	18.75%	$0.0000	0.00%	0.1875		3.57%
Lrg Vol Inter. Service	$0.1875	4.63%	18.75%	$0.0000	0.00%	0.1875		4.21%
Sm Vol Joint Service	$0.1875	4.63%	18.75%	($1.3380)	-7.08%	0.1875	***	3.67%
Lrg Vol Joint Service	$0.1875	4.63%	18.75%	($1.8609)	-9.59%	0.1875	***	4.26%

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

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2014 Change in Entitlement Levels and Related Demand Costs

NNG

	Contract	Aug-14 PGA	Nov-14 Entitlement	Entitlement Change	Months	Nov-14 Rate/MCF	Aug-14 Total Cost	Entitlement Total Cost	Entitlement Change
TF12B (Max Rate) Winter	112495	0	43,953	43,953	5	$ 10.2300	$0	$2,248,196	$2,248,196
TF12B (Max Rate) Summer	112495	0	43,190	43,190	7	$ 5.6830	$0	$1,718,141	$1,718,141
TF12B	112495	43,953	0	(43,953)	12	$ 7.5171	$3,964,789	$0	($3,964,789)
TF12V (Max Rate)	112495	26,926	26,926	0	12	$ 9.0926	$2,937,928	$2,937,928	$0
TF5 (Max Rate)	112495	31,515	31,515	0	5	$ 15.1530	$2,387,734	$2,387,734	($0)
TF12B (Discount-Winter)	112495	5,200	5,200	0	12	$ 7.4951	$467,694	$467,694	$0
TFX5 (Discount)	112561	6,000	0	(6,000)	5	$ 4.5600	$136,800	$0	($136,800)
TFX12 (Max Rate)	112486	10,822	10,822	0	12	$ 9.6288	$1,250,434	$1,250,434	$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
TFX5 (Max Rate)	112486	60,271	66,271	6,000	5	$ 15.1530	$4,566,432	$5,021,022	$454,590
TFX5 (Discount)	112486	1,800	1,800	0	5	$ 7.6000	$68,400	$68,400	$0
TFX12 (Discount)	111866	1,283	1,283	0	12	$ 4.8640	$74,886	$74,886	$0
TFX12 (Discount)	111866	8,271	8,271	0	12	$ 5.4720	$543,107	$543,107	($0)
TFX12 (Discount)	111866	11,921	11,921	0	12	$ 7.6025	$1,087,553	$1,087,553	($0)
TFX5 (Discount)	111866	379	379	0	5	$ 4.8640	$9,217	$9,217	$0
TFX5 (Discount)	111866	2,445	2,445	0	5	$ 5.4720	$66,895	$66,895	$0
TFX5 (Discount)	111866	22,189	22,189	0	5	$ 15.1392	$1,679,619	$1,679,619	($0)
Bison	FT0003	50,000	50,000	0	12	$ 17.4896	$10,493,760	$10,493,750	($10)
NBPL	T8673F	50,000	50,000	0	12	$ 6.9958	$4,197,480	$4,197,500	$20
Windom		2,500	2,500	0	12	$ -	$0	$0	$0
Ortonville		910	910	0	12	$ 8.0000	$87,360	$87,360	$0
NNG Zone GDD Call Option		20,000	20,000	0	3	$ 0.9000	$54,000	$54,000	$0
Total Demand Cost							$34,096,820	$34,416,169	$319,349

Costs Assigned In Commodity:		Aug-14 PGA	Nov-14 Entitlement	Entitlement Change	Months	Nov-14 Rate/MCF	Aug-14 Total Cost	Entitlement Total Cost	Entitlement Change
Upstream				0				$0	$0
Surcharges:				0				$0	$0
				0				$0	$0
Storage (FDD)									
Storage Reservation	118657	75,437	75,437	0	12	$ 1.7140	$1,551,588	$1,551,588	$0
Storage Cycle Volume	118657	869,864	869,864	0	5	$ 0.3567	$1,551,402	$1,551,402	$0
Storage Reservation	118657	5,550	5,550	0	12	$ 3.3157	220826	$220,826	($0)
Storage Cycle Volume	118657	64,000	64,000	0	5	$ 0.6901	$220,832	$220,832	$0
Storage Reservation	125915	13,009	2,602	(10,407)	12	$ 1.7140	$267,569	$53,518	($214,051)
Storage Cycle Volume	125915	150,000	30,000	(120,000)	5	$ 0.3567	$267,525	$53,505	($214,020)
Storage Reservation	125916	3,468	11,274	7,806	12	$ 1.7140	$71,330	$231,884	$160,554
Storage Cycle Volume	125916	40,000	130,000	90,000	5	$ 0.3567	$71,340	$231,855	$160,515
SMS-Bal Service		272,160	272,160	0	1	$ 2.1800	$593,309	$593,309	($0)
Producer Demand Payments/Option Premium							$1,269,879	$1,549,901	$280,022
Total Commodity Costs							$6,085,601	$6,258,620	$173,019

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2013 through June 30, 2014

NNG

Attachment 13

Base	41,361
Variable	2,341

Date	12.04% Cloquet Adjusted HDD	28.20% Minneapolis Adjusted HDD	47.24% Rochester Adjusted HDD	12.52% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/13	4	0	0	0	0	50,494	42,522
7/2/13	2	0	0	0	0	49,986	41,936
7/3/13	0	0	0	0	0	45,362	41,361
7/4/13	0	0	0	0	0	37,892	41,361
7/5/13	0	0	0	0	0	42,393	41,361
7/6/13	5	0	0	0	1	39,459	42,883
7/7/13	1	0	0	0	0	44,996	41,651
7/8/13	1	0	0	0	0	52,003	41,657
7/9/13	0	0	0	0	0	49,286	41,361
7/10/13	0	0	0	0	0	52,536	41,361
7/11/13	0	0	0	0	0	51,561	41,361
7/12/13	0	0	0	0	0	45,400	41,361
7/13/13	0	0	0	0	0	38,769	41,361
7/14/13	0	0	0	0	0	43,076	41,361
7/15/13	0	0	0	0	0	50,907	41,361
7/16/13	0	0	0	0	0	60,710	41,361
7/17/13	0	0	0	0	0	63,035	41,361
7/18/13	0	0	0	0	0	58,928	41,361
7/19/13	4	0	0	0	1	51,847	42,556
7/20/13	6	0	0	0	1	37,692	43,187
7/21/13	0	0	0	0	0	42,140	41,361
7/22/13	4	0	0	0	1	50,762	42,545
7/23/13	5	0	0	1	1	51,676	43,134
7/24/13	0	0	0	0	0	52,292	41,361
7/25/13	11	1	5	0	4	50,465	50,165
7/26/13	17	7	12	9	11	47,195	66,763
7/27/13	9	2	8	10	6	42,411	56,470
7/28/13	6	0	3	5	3	44,081	48,139
7/29/13	0	0	0	0	0	52,512	41,361
7/30/13	0	0	0	1	0	57,396	41,666
7/31/13	0	0	0	0	0	54,470	41,361
8/1/13	3	0	0	0	0	53,062	42,266
8/2/13	6	0	0	5	1	45,603	44,677
8/3/13	6	0	2	4	2	42,470	46,690
8/4/13	1	0	0	0	0	40,920	41,648
8/5/13	1	0	0	0	0	50,499	41,654
8/6/13	5	0	0	0	1	52,285	42,869
8/7/13	3	0	0	0	0	52,753	42,232
8/8/13	8	0	0	1	1	56,898	43,805
8/9/13	2	0	1	1	1	48,154	43,408
8/10/13	3	0	0	0	0	41,956	42,232
8/11/13	5	0	0	0	1	43,303	42,855
8/12/13	8	0	3	0	3	50,787	47,222
8/13/13	7	0	3	2	3	51,494	47,484
8/14/13	3	0	2	3	2	55,399	45,517
8/15/13	0	0	0	7	1	50,708	43,495
8/16/13	0	0	0	2	0	43,348	41,994
8/17/13	0	0	0	0	0	37,087	41,361
8/18/13	0	0	0	0	0	45,236	41,361
8/19/13	0	0	0	0	0	51,818	41,361
8/20/13	0	0	0	0	0	51,712	41,361
8/21/13	0	0	0	0	0	50,062	41,361
8/22/13	1	0	0	0	0	51,602	41,651
8/23/13	0	0	0	0	0	47,374	41,361
8/24/13	0	0	0	0	0	39,972	41,361
8/25/13	0	0	0	0	0	44,225	41,361
8/26/13	0	0	0	0	0	51,305	41,361
8/27/13	0	0	0	0	0	49,798	41,361
8/28/13	0	0	0	0	0	51,870	41,361
8/29/13	0	0	0	0	0	54,405	41,361
8/30/13	0	0	0	0	0	46,048	41,361
8/31/13	2	0	0	0	0	39,408	41,987
9/1/13	11	4	9	4	7	39,784	57,963
9/2/13	7	0	5	4	4	47,644	50,433
9/3/13	6	0	0	0	1	54,040	43,119
9/4/13	7	0	0	0	1	55,983	43,393
9/5/13	0	0	0	0	0	54,327	41,361
9/6/13	0	0	0	0	0	48,291	41,361
9/7/13	5	0	0	0	1	45,163	42,855
9/8/13	3	0	0	0	0	45,642	42,223
9/9/13	0	0	0	0	0	58,803	41,361
9/10/13	1	0	0	0	0	62,275	41,665
9/11/13	12	0	3	0	3	59,864	48,391
9/12/13	15	5	8	7	8	55,170	60,623
9/13/13	10	3	7	5	6	48,760	55,107
9/14/13	20	8	10	3	10	43,909	63,917
9/15/13	18	10	12	13	12	51,015	69,408
9/16/13	13	7	13	9	11	60,142	66,668

MERC

Attachment 13

9/17/13	5	0	0	3	1	56,716	43,834
9/18/13	1	0	0	0	0	57,047	41,654
9/19/13	11	8	10	4	9	57,654	62,139
9/20/13	15	10	12	20	12	58,282	70,608
9/21/13	16	4	9	6	8	50,044	60,508
9/22/13	9	1	6	0	4	49,170	50,767
9/23/13	6	1	7	0	4	56,012	51,058
9/24/13	8	1	7	5	5	56,736	53,204
9/25/13	7	0	0	0	1	56,527	43,472
9/26/13	1	0	0	0	0	56,188	41,663
9/27/13	8	4	8	0	6	52,067	55,294
9/28/13	9	2	8	11	7	50,978	57,194
9/29/13	0	0	1	0	1	51,303	42,677
9/30/13	6	0	0	0	1	59,219	42,911
10/1/13	8	3	6	4	5	69,594	53,192
10/2/13	13	8	3	0	5	65,369	53,702
10/3/13	16	9	6	9	8	66,160	60,699
10/4/13	21	12	13	17	14	58,469	74,338
10/5/13	18	18	19	21	19	62,374	85,490
10/6/13	17	10	11	23	13	73,237	71,418
10/7/13	8	1	5	8	4	76,747	51,624
10/8/13	2	0	3	1	2	68,211	46,050
10/9/13	5	0	4	0	3	65,127	47,750
10/10/13	3	0	2	0	2	54,427	44,879
10/11/13	11	15	16	8	14	54,022	74,621
10/12/13	21	15	19	19	18	65,048	83,861
10/13/13	23	18	19	15	19	74,019	85,251
10/14/13	23	17	16	18	17	93,518	81,770
10/15/13	21	18	27	24	23	93,772	96,000
10/16/13	26	15	23	22	21	103,116	90,200
10/17/13	24	22	26	22	24	108,623	97,545
10/18/13	29	24	29	26	28	111,310	106,025
10/19/13	34	27	28	26	28	117,112	107,556
10/20/13	38	34	38	25	35	123,082	123,624
10/21/13	36	32	36	28	34	163,407	121,264
10/22/13	36	32	35	33	34	157,487	121,069
10/23/13	33	29	33	35	32	168,604	116,858
10/24/13	29	23	29	31	28	156,612	106,119
10/25/13	28	25	27	24	26	123,727	102,086
10/26/13	28	21	24	32	25	124,993	99,681
10/27/13	34	28	27	23	28	117,072	106,435
10/28/13	37	31	25	32	29	151,427	109,732
10/29/13	30	24	20	26	23	139,226	94,603
10/30/13	24	20	17	25	20	113,393	88,065
10/31/13	26	25	27	29	27	127,997	103,751
11/1/13	31	25	26	27	26	130,046	102,882
11/2/13	30	24	29	23	27	138,715	104,554
11/3/13	22	18	21	19	20	114,180	87,763
11/4/13	30	26	28	29	28	141,938	106,655
11/5/13	34	29	31	40	32	152,358	116,692
11/6/13	39	33	35	39	35	150,822	124,000
11/7/13	41	36	36	38	37	163,725	127,874
11/8/13	36	30	32	27	31	138,186	115,079
11/9/13	36	30	32	36	32	133,889	117,298
11/10/13	41	36	34	40	36	135,223	125,857
11/11/13	56	50	55	61	55	195,890	169,095
11/12/13	47	45	51	52	49	184,801	155,994
11/13/13	32	27	34	27	31	146,246	113,990
11/14/13	28	24	31	24	28	142,533	106,655
11/15/13	25	20	22	23	22	120,393	92,879
11/16/13	23	22	21	21	21	100,929	91,012
11/17/13	36	33	35	31	34	137,135	121,127
11/18/13	46	38	41	33	40	167,552	134,604
11/19/13	37	32	35	24	33	145,391	118,438
11/20/13	30	27	31	34	30	143,060	111,936
11/21/13	50	46	46	61	48	183,219	154,285
11/22/13	54	50	55	56	54	199,322	166,930
11/23/13	63	55	62	60	60	215,695	181,042
11/24/13	49	48	57	50	53	179,535	164,281
11/25/13	47	41	41	42	42	167,090	139,004
11/26/13	60	54	58	59	57	215,488	175,111
11/27/13	53	49	51	52	51	190,639	160,414
11/28/13	59	46	49	51	49	180,957	157,191
11/29/13	48	43	44	44	44	169,625	144,463
11/30/13	36	35	33	35	34	141,935	121,306
12/1/13	43	36	37	36	37	154,330	128,481
12/2/13	39	33	34	30	34	159,074	120,390
12/3/13	41	35	34	40	36	166,309	125,381
12/4/13	52	52	51	60	53	201,073	164,683
12/5/13	73	70	70	79	71	259,103	208,271
12/6/13	82	75	72	81	75	275,153	217,215
12/7/13	81	71	67	71	70	261,158	205,833
12/8/13	73	65	64	71	66	243,830	196,598
12/9/13	77	68	71	71	71	279,992	206,997
12/10/13	80	68	70	71	71	272,689	207,068
12/11/13	80	68	72	73	72	281,572	210,125
12/12/13	67	54	52	52	54	233,152	168,168
12/13/13	69	57	54	60	58	235,989	176,164
12/14/13	75	63	66	64	66	242,974	195,278

MERC

Attachment 13

12/15/13	79	66	66	65	67	250,607	199,375
12/16/13	58	51	53	52	53	228,493	164,719
12/17/13	59	51	55	48	53	222,310	165,739
12/18/13	58	41	41	49	44	193,728	144,371
12/19/13	61	54	52	64	55	225,365	169,946
12/20/13	57	49	49	59	51	215,440	161,236
12/21/13	54	50	51	61	52	205,398	163,513
12/22/13	70	63	68	75	68	241,629	200,467
12/23/13	79	77	81	80	79	285,291	227,444
12/24/13	71	67	70	62	68	235,724	200,574
12/25/13	58	49	52	46	51	200,830	160,399
12/26/13	57	46	46	47	47	193,806	151,954
12/27/13	39	37	40	38	38	161,373	131,474
12/28/13	63	48	50	60	52	183,175	163,968
12/29/13	86	77	78	76	78	275,395	225,128
12/30/13	79	72	75	64	73	281,745	213,032
12/31/13	86	74	75	77	76	278,833	219,476
1/1/14	83	74	75	82	77	277,248	220,836
1/2/14	79	72	78	75	76	288,267	220,135
1/3/14	62	52	58	53	56	232,162	173,002
1/4/14	79	68	70	72	71	256,427	207,358
1/5/14	91	90	95	92	93	300,315	258,242
1/6/14	95	89	94	85	92	310,124	255,593
1/7/14	82	71	73	63	73	295,830	211,469
1/8/14	78	70	77	66	74	297,517	213,785
1/9/14	61	57	61	57	59	238,587	179,986
1/10/14	44	41	41	46	42	181,551	139,779
1/11/14	45	41	45	41	44	174,737	143,403
1/12/14	39	33	35	39	36	152,994	124,551
1/13/14	49	43	42	41	43	182,482	141,841
1/14/14	67	61	67	61	64	234,565	191,996
1/15/14	56	50	58	54	55	219,620	169,879
1/16/14	67	60	60	63	61	251,340	183,892
1/17/14	62	62	66	54	63	235,470	188,286
1/18/14	51	49	56	51	53	194,608	165,362
1/19/14	55	37	41	36	41	168,616	137,552
1/20/14	82	68	68	66	69	267,929	203,742
1/21/14	79	72	75	71	74	275,195	215,192
1/22/14	88	82	84	78	84	305,545	236,900
1/23/14	78	69	78	71	75	290,343	216,053
1/24/14	61	54	57	50	56	213,218	171,564
1/25/14	70	67	64	50	64	230,378	190,859
1/26/14	84	77	81	70	79	246,423	225,283
1/27/14	89	83	89	81	86	277,268	242,860
1/28/14	83	77	82	76	80	271,765	228,407
1/29/14	65	51	60	50	57	217,374	174,560
1/30/14	76	67	64	65	66	258,878	196,320
1/31/14	73	67	71	62	69	256,280	202,297
2/1/14	71	62	67	68	66	243,535	195,691
2/2/14	67	64	70	62	67	248,006	197,845
2/3/14	64	59	60	62	60	249,302	182,646
2/4/14	72	68	68	77	70	266,648	204,470
2/5/14	76	75	80	78	78	290,770	223,487
2/6/14	75	74	79	78	77	284,856	221,769
2/7/14	76	66	70	67	69	261,562	203,161
2/8/14	67	62	65	69	65	244,121	193,637
2/9/14	77	75	79	78	78	276,780	222,919
2/10/14	78	70	79	75	76	296,445	218,740
2/11/14	69	66	73	67	70	260,795	204,977
2/12/14	55	48	54	53	52	225,638	164,263
2/13/14	64	55	58	54	57	247,712	175,842
2/14/14	67	61	69	65	66	244,443	195,713
2/15/14	63	57	60	51	58	223,836	178,132
2/16/14	63	55	60	56	58	208,034	178,087
2/17/14	46	44	47	39	45	199,032	147,187
2/18/14	37	34	40	38	38	165,814	130,059
2/19/14	33	36	39	33	37	153,192	127,584
2/20/14	52	52	53	53	52	196,704	164,167
2/21/14	68	63	65	54	64	228,687	190,352
2/22/14	66	64	68	60	65	222,741	194,583
2/23/14	66	64	71	59	67	232,251	197,636
2/24/14	73	66	72	65	70	259,187	204,117
2/25/14	78	74	81	75	78	289,751	224,283
2/26/14	82	74	79	73	77	291,062	221,614
2/27/14	77	75	80	73	77	288,662	221,748
2/28/14	73	65	66	68	67	262,972	197,832
3/1/14	86	81	82	83	82	290,099	234,099
3/2/14	81	73	81	76	78	287,677	224,741
3/3/14	69	66	69	66	68	268,127	199,482
3/4/14	61	53	55	59	55	225,355	171,267
3/5/14	59	50	58	57	56	212,031	171,740
3/6/14	48	46	50	44	48	191,559	153,134
3/7/14	50	46	41	56	45	188,843	147,723
3/8/14	49	45	52	50	49	169,607	157,060
3/9/14	36	32	39	30	35	137,893	124,242
3/10/14	24	21	28	23	25	117,272	99,636
3/11/14	46	38	41	39	41	167,613	136,863
3/12/14	50	39	48	38	45	183,505	145,795
3/13/14	32	24	31	21	28	130,788	107,338

MERC

	3/14/14	45	37	39	33	38	158,184	131,243
	3/15/14	59	49	50	49	51	177,122	160,289
	3/16/14	46	44	48	47	47	179,674	150,410
Attachment 13	3/17/14	42	36	38	31	37	165,660	127,328
	3/18/14	41	38	35	38	37	158,642	128,534
	3/19/14	46	36	39	34	38	166,001	130,570
	3/20/14	33	29	34	28	32	135,837	116,045
	3/21/14	54	44	42	44	45	172,277	145,676
	3/22/14	64	55	57	53	57	198,578	173,753
	3/23/14	60	44	45	46	47	195,002	150,606
	3/24/14	59	52	52	51	53	200,270	164,334
	3/25/14	59	47	51	50	51	211,232	159,631
	3/26/14	40	32	35	30	34	158,730	121,377
	3/27/14	45	36	37	42	38	162,980	130,709
	3/28/14	46	36	37	45	39	150,573	132,234
	3/29/14	32	26	28	32	28	118,070	107,677
	3/30/14	24	13	18	11	16	100,127	79,600
	3/31/14	45	30	30	29	32	137,588	116,358
	4/1/14	46	37	36	41	38	175,169	130,696
	4/2/14	36	32	30	38	32	138,246	116,381
	4/3/14	39	37	40	40	39	163,682	133,194
	4/4/14	36	30	32	38	33	144,608	118,436
	4/5/14	23	15	19	31	20	106,202	87,370
	4/6/14	26	17	19	17	19	90,062	85,723
	4/7/14	30	23	25	21	24	103,963	98,679
	4/8/14	24	13	20	26	19	112,266	86,734
	4/9/14	25	14	17	9	16	83,843	79,195
	4/10/14	20	13	15	16	15	92,638	77,000
	4/11/14	31	17	21	8	19	77,622	86,044
	4/12/14	35	31	32	12	30	88,614	110,522
	4/13/14	47	40	42	45	42	139,985	139,986
	4/14/14	46	40	40	46	42	172,196	138,727
	4/15/14	44	37	29	38	34	150,964	121,499
	4/16/14	36	33	32	36	33	150,497	119,584
	4/17/14	39	28	26	33	29	144,168	109,601
	4/18/14	28	11	14	18	16	105,337	77,890
	4/19/14	19	5	5	6	7	73,894	57,672
	4/20/14	19	10	12	0	11	59,301	66,292
	4/21/14	24	19	21	19	21	88,098	89,790
	4/22/14	27	24	26	11	23	97,687	96,110
	4/23/14	33	25	25	22	26	122,600	101,809
	4/24/14	31	16	18	20	19	126,572	86,520
	4/25/14	32	22	21	11	21	90,363	91,144
	4/26/14	38	29	27	15	28	90,599	105,837
	4/27/14	34	26	27	20	27	119,095	104,447
	4/28/14	31	32	32	29	32	137,739	115,234
	4/29/14	31	28	31	32	30	142,398	112,703
	4/30/14	26	25	26	30	26	130,985	103,185
	5/1/14	25	16	17	28	19	114,402	85,857
	5/2/14	24	16	17	17	18	86,076	82,444
	5/3/14	24	19	18	18	19	79,875	86,669
	5/4/14	25	9	11	22	13	77,868	72,782
	5/5/14	28	10	12	11	13	79,417	72,288
	5/6/14	21	8	8	6	9	76,626	63,534
	5/7/14	22	5	0	0	4	70,931	51,292
	5/8/14	26	13	18	6	16	72,525	78,125
	5/9/14	14	10	13	13	12	82,643	69,994
	5/10/14	12	6	4	6	6	54,506	55,384
	5/11/14	27	10	4	12	10	53,997	63,775
	5/12/14	20	19	22	26	21	80,194	91,612
	5/13/14	23	17	19	22	20	88,383	87,126
	5/14/14	26	22	23	21	23	85,978	94,394
	5/15/14	22	19	22	32	23	102,029	94,472
	5/16/14	21	13	16	21	16	87,539	78,820
	5/17/14	6	6	8	9	7	57,073	58,293
	5/18/14	16	12	11	0	10	51,295	65,079
	5/19/14	5	0	0	4	1	72,103	44,116
	5/20/14	13	7	7	2	7	62,361	57,575
	5/21/14	12	6	8	8	8	67,382	59,540
	5/22/14	9	2	2	1	3	58,628	47,935
	5/23/14	1	0	1	0	1	46,617	42,879
	5/24/14	0	0	0	0	0	37,057	41,361
	5/25/14	0	0	0	0	0	38,704	41,361
	5/26/14	11	0	0	0	1	47,309	44,404
	5/27/14	11	0	0	0	1	65,305	44,348
	5/28/14	4	0	0	0	0	55,545	42,522
	5/29/14	5	0	0	0	1	55,336	42,840
	5/30/14	5	0	0	0	1	53,706	42,826
	5/31/14	2	0	0	0	0	43,904	41,942
	6/1/14	2	0	0	0	0	46,347	41,975
	6/2/14	2	0	1	1	1	58,867	43,504
	6/3/14	5	0	0	1	1	34,875	43,157
	6/4/14	9	0	0	0	1	58,901	43,999
	6/5/14	0	0	0	0	0	56,271	41,361
MERC	6/6/14	11	6	1	0	4	52,135	49,848
	6/7/14	11	4	3	11	5	44,262	54,171
	6/8/14	7	0	0	3	1	45,560	44,351
	6/9/14	8	0	0	5	2	58,413	45,259
	6/10/14	7	0	0	0	1	59,435	43,413

6/11/14	18	6	7	0	7	59,601	58,238
6/12/14	9	2	3	8	4	61,776	51,345
6/13/14	15	3	0	0	3	49,029	47,979
6/14/14	7	0	0	2	1	43,098	43,907
6/15/14	0	0	0	0	0	46,623	41,361
6/16/14	0	0	0	0	0	59,635	41,361
6/17/14	6	0	0	0	1	56,975	42,981
6/18/14	13	0	0	0	2	56,330	45,047
6/19/14	15	0	0	0	2	56,109	45,622
6/20/14	6	0	0	0	1	50,436	43,119
6/21/14	9	0	0	0	1	39,496	43,973
6/22/14	0	0	0	0	0	46,058	41,361
6/23/14	13	0	0	0	2	55,396	45,047
6/24/14	14	2	0	0	2	56,699	46,694
6/25/14	11	0	0	0	1	59,819	44,376
6/26/14	9	0	0	0	1	56,040	43,773
6/27/14	0	0	0	0	0	50,652	41,361
6/28/14	0	0	0	0	0	41,907	41,361
6/29/14	0	0	0	0	0	47,729	41,361
6/30/14	1	0	3	0	2	55,559	45,450
Totals	11,522	9,475	10,104	9,840	10,064	########	38,657,124

* 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, 2013 through June 30, 2014

Attachment 14

Rate Class	Tariff Rate Designation	Jul-13 Average Customers	Aug-13 Average Customers	Sep-13 Average Customers	Oct-13 Average Customers	Nov-13 Average Customers	Dec-13 Average Customers	Jan-14 Average Customers	Feb-14 Average Customers	Mar-14 Average Customers	Apr-14 Average Customers	May-14 Average Customers	Jun-14 Average Customers	Annual Average Customers
GS- Residential (w/ Heat)	2H801 / 2HS01 2HS02	160,366	161,713	161,822	162,267	162,257	163,703	167,028	163,698	164,199	158,550	162,775	163,807	162,682
GS-Residential (w/o Heat)	2R801 / 2RS01 2RS02	921	939	933	938	932	942	965	942	945	917	929	935	937
GS-C&I <1,500 therms/yr (Small)	2C805 / 2CS05 2I805 / 2IS05 2C806 / 2CS06 2CS07 / 2IS07 2CS08	8,197	8,230	8,222	8,253	8,255	8,332	8,545	8,405	8,398	8,139	8,291	8,359	8,302
GS-C&I <1,500 therms/yr (Small) Emmons, IA	2CE05	2	2	2	2	2	2	2	2	2	2	2	2	2
GS-C&I >1,500 therms/yr (Large)	2C810 / 2CS10 2I810 / 2IS10 2CS11 / 2IS11 2C812/ 2CS12 2IS12	7,813	7,824	7,810	7,835	7,843	7,862	8,079	7,918	7,876	7,680	7,848	7,893	7,857
GS-C&I >1,500 therms/yr (Large) Emmons, IA	2CE10	1	1	1	1	1	1	1	1	1	1	1	1	1
Small Volume Interruptible (SVI)	2D820 / 2DS20 2J820 / 2JS20 2DS22	308	311	312	317	316	308	315	306	305	302	304	301	309
Small Volume Interrupt	2C830 / 2CS30 2C830	0	0	0	0	0	0	0	3	3	3	3	3	1
Large Volume Interrupt	2D840 / 2DS40 2J840 / 2JS40 2D842	57	56	59	62	59	57	61	58	58	63	67	60	60
Large Volume Interrupt	2IS50 / 2JS50	0	0	0	0	0	0	0	0	0	0	0	0	0
Super Large Volume In	2DS60 / 2JS60	0	0	0	0	0	0	0	0	0	0	0	0	0
Super Large Volume In	2IS70 / 2JS70	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		177,665	179,076	179,161	179,675	179,665	181,207	184,996	181,333	181,787	175,657	180,220	181,361	180,150

MINNESOTA ENERGY RESOURCES - NNG

Projected Fixed Cost - November 2014 through March 2015

Futures Contracts WACOG

NNG-PNG
Futures

Nov-14 (30)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/25/14	81,552	$ 4.5750	$ 373,099	$ 3.9955	$ 325,840	$ 47,259
07/25/14	88,966	$ 3.8470	$ 342,250	$ 3.9955	$ 355,462	$ (13,211)
08/xx/14	88,966	$ 3.8580	$ 343,229	$ 3.9955	$ 355,462	$ (12,233)
09/xx14	88,966	$ 3.8580	$ 343,229	$ 3.9955	$ 355,462	$ (12,233)
10/xx14	81,552	$ 3.8580	$ 314,627	$ 3.9955	$ 325,840	$ (11,213)
Total	430,000		$ 1,716,434		$ 1,718,065	$ (1,631)
WACOG			$ 3.9917		3.9955	$ (0.0063)

Dec-14 (31)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/16/14	3,529	$ 4.7950	$ 16,924	$ 4.2065	$ 14,846	$ 2,077
06/16/14	7,059	$ 4.8020	$ 33,896	$ 4.2065	$ 29,693	$ 4,204
07/16/14	14,118	$ 4.2330	$ 59,760	$ 4.2065	$ 59,386	$ 374
8/xx/2014	14,118	$ 3.9390	$ 55,609	$ 4.2065	$ 59,386	$ (3,776)
9/xx/2014	10,588	$ 3.9390	$ 41,707	$ 4.2065	$ 44,539	$ (2,832)
10/xx/2014	10,588	$ 3.9390	$ 41,707	$ 4.2065	$ 44,539	$ (2,832)
Total	60,000		$ 249,604		$ 252,390	$ (2,786)
WACOG			$ 4.1601		$ 4.2065	$ (0.0464)

Jan-15 (31)						
Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/11/14	6,939	$ 4.6790	$ 32,467	$ 4.3310	$ 30,052	$ 2,415
06/11/14	48,571	$ 4.6800	$ 227,314	$ 4.3310	$ 210,363	$ 16,951
07/10/14	13,878	$ 4.2950	$ 59,604	$ 4.3310	$ 60,104	$ (500)
07/10/14	62,449	$ 4.2960	$ 268,281	$ 4.3310	$ 270,467	$ (2,186)
8/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
9/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
10/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
Total	340,000		$ 1,422,609		$ 1,472,540	$ (49,931)
WACOG			$ 4.1841		$ 4.3310	$ (0.1469)

Feb-15 (28)						
Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/30/14	35,625	$ 4.5720	$ 162,877	$ 4.2985	$ 153,134	$ 9,743
07/30/14	41,563	$ 4.0100	$ 166,666	$ 4.2985	$ 178,656	$ (11,991)
8/xx/2014	41,563	$ 4.0010	$ 166,292	$ 4.2985	$ 178,656	$ (12,365)
9/xx/2014	35,625	$ 4.0010	$ 142,536	$ 4.2985	$ 153,134	$ (10,598)
10/xx/2014	35,625	$ 4.0010	$ 142,536	$ 4.2985	$ 153,134	$ (10,598)
Total	190,000		$ 780,906		$ 816,715	$ (35,809)
WACOG			$ 4.1100		$ 4.2985	$ (0.1885)

Mar-15 (31)						
Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/20/14	38,542	$ 4.5650	$ 175,943	$ 4.1410	$ 159,601	$ 16,342
06/20/14	38,542	$ 4.5750	$ 176,328	$ 4.1410	$ 159,601	$ 16,727
06/20/14	38,542	$ 4.5770	$ 176,405	$ 4.1410	$ 159,601	$ 16,804
06/20/14	38,542	$ 4.5790	$ 176,482	$ 4.1410	$ 159,601	$ 16,881
07/21/14	154,167	$ 3.9850	$ 614,354	$ 4.1410	$ 638,404	$ (24,050)
8/xx/2014	146,458	$ 3.9360	$ 576,460	$ 4.1410	$ 606,484	$ (30,024)
9/xx/2014	146,458	$ 3.9360	$ 576,460	$ 4.1410	$ 606,484	$ (30,024)
10/xx/2014	138,750	$ 3.9360	$ 546,120	$ 4.1410	$ 574,564	$ (28,444)
Total	740,000		$ 3,018,553		$ 3,064,340	$ (45,787)
WACOG			$ 4.0791		$ 4.1410	$ (0.0619)

Total						
	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	166,187	$ 4.5811	$ 761,309	$ 4.1127	$ 683,473	$ 77,836
	224,700	$ 4.2121	$ 946,455	$ 4.1557	$ 933,775	$ 12,680
	197,065	$ 4.0864	$ 805,290	$ 4.1266	$ 813,209	$ (7,919)
	239,699	$ 4.1141	$ 986,137	$ 4.1638	$ 998,049	$ (11,912)
	351,319	$ 3.9609	$ 1,391,538	$ 4.1627	$ 1,462,436	$ (70,898)
	226,434	$ 3.9591	$ 896,481	$ 4.2023	$ 951,542	$ (55,060)
	215,846	$ 3.9601	$ 854,774	$ 4.2021	$ 907,002	$ (52,228)
	138,750	$ 3.9360	$ 546,120	$ 4.1410	$ 574,564	$ (28,444)
	1,760,000		$ 7,188,105		$ 7,324,050	$ (135,945)
			$ 4.0842		$ 4.1614	$ (0.0772)

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2014 through March 2015

Month/ Year	K#118657 NNG Storage	Storage K#125915 NNG Storage	Storage K#125916 NNG Storage	Total NNG Storage	Projected Storage NNG WACOG	K#118657 NNG Storage Cost	K#125915 NNG Storage Cost	K#125916 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-14	455,259	14,625	63,375	533,259	$ 4.1998	$ 1,912,006	$ 61,422	$ 266,164	$ 2,239,593	85,304	$ 4.2134	$ 359,423
Dec-14	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	231,769	$ 4.2134	$ 976,543
Jan-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	231,769	$ 4.2134	$ 976,543
Feb-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	209,339	$ 4.2134	$ 882,035
Mar-15	455,259	14,625	63,375	533,259	$ 4.1998	$ 1,912,006	$ 61,422	$ 266,164	$ 2,239,593	96,374	$ 4.2134	$ 406,065
Total	4,342,470	139,500	604,500	5,086,470	$ 4.1998	$ 18,237,598	$ 585,875	$ 2,538,792	$ 21,362,265	854,555	$ 4.2134	$ 3,600,608

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson LDS + Basis	Emerson LDS + Cost
Nov-14	533,259	$ 3.9955	$ 2,130,636	85,304	$ 4.2080	$ 358,959
Dec-14	1,339,984	$ 4.2065	$ 5,636,643	231,769	$ 4.4890	$ 1,040,411
Jan-15	1,339,984	$ 4.3310	$ 5,803,471	231,769	$ 4.8310	$ 1,119,676
Feb-15	1,339,984	$ 4.2985	$ 5,759,921	209,339	$ 4.7110	$ 986,196
Mar-15	533,259	$ 4.1410	$ 2,208,226	96,374	$ 4.5560	$ 439,080
Total	5,086,470	$ 4.2345	$ 21,538,896	854,555	$ 4.6156	$ 3,944,322

Max NNG Storage (Storage plan withdrawals through Apr 14	5,086,470	5,469,321	07/30/14 Storage Balance - NNG	2,095,947	38.32%	1,949,231
Max AECO Storage	854,555	947,820	07/30/14 Storage Balance - AECO	567,143	59.84%	511,336
						41.42%

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-14	455,259	14,625	63,375	533,259	$ 4.1998	$ 4.1998	$ 4.1998	$ 2,239,593	$ 3.9955	$ 2,130,636	$ 108,956
Dec-14	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.2065	$ 5,636,643	$ (8,949)
Jan-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.3310	$ 5,803,471	$ (175,777)
Feb-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.2985	$ 5,759,921	$ (132,228)
Mar-15	455,259	14,625	63,375	533,259	$ 4.1998	$ 4.1998	$ 4.1998	$ 2,239,593	$ 4.1410	$ 2,208,226	$ 31,367
Total	4,342,470	139,500	604,500	5,086,470	$ 4.1998	$ 4.1998	$ 4.1998	$ 21,362,265	$ 4.2345	$ 21,538,896	$ (176,631)
								$ 4.1998	$ (0.2690)	$ (176,631)	

Month/ Year	AECO Storage	AECO Storage Other WACOG	Total AECO Cost	Projected Emerson Index Price	Projected Emerson Index Cost	Additional Storage (Savings)/ Cost
Nov-14	85,304	$ 4.2134	$ 359,423	$ 4.2080	$ 358,959	$ 463
Dec-14	231,769	$ 4.2134	$ 976,543	$ 4.4890	$1,040,411	$ (63,868)
Jan-15	231,769	$ 4.2134	$ 976,543	$ 4.8310	$1,119,676	$ (143,133)
Feb-15	209,339	$ 4.2134	$ 882,035	$ 4.7110	$ 986,196	$ (104,161)
Mar-15	96,374	$ 4.2134	$ 406,065	$ 4.5560	$ 439,080	$ (33,015)
Total	854,555	$ 4.2134	$ 3,600,608	$ 4.6156	$3,944,322	$ (343,714)
			$ 3.2341	$ (0.8488)	$ (343,714)	

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2014 through March 201!

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-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	06/13/14		17	170,000	$ 5.0000	$ 850,000	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2380	$ 40,460	$ 696,320
2	07/14/14		17	170,000	$ 4.2500	$ 722,500	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2220	$ 37,740	$ 693,600
3	8/xx/2014		17	170,000	$ 4.0000	$ 680,000	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2300	$ 39,100	$ 694,960
4	9/xx/2014		19	190,000	$ 4.0000	$ 760,000	$ 3.8580	$ 733,020	$ 3.8580	$ 733,020	$ -	$ 0.2300	$ 43,700	$ 776,720
5	10/xx/2014		19	190,000	$ 4.0000	$ 760,000	$ 3.8580	$ 733,020	$ 3.8580	$ 733,020	$ -	$ 0.2300	$ 43,700	$ 776,720
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			89	890,000		$ 3,772,500		$ 3,433,620		$ 3,433,620	$ -		$ 204,700	$ 3,638,320
						$ 4.2388		$ 3.8580		$ 3.8580	$ -		$ 0.0543	$ 4.0880
NNG-Cons	72	80.90%	72	720,000	$ 4.2388	$ 3,051,910	$ 3.8580	$ 2,777,760	$ 3.6613	$ 2,777,760	$ -	$ 0.2300	$ 165,600	$ 2,943,360
Other-Cons	17	19.10%	17	170,000	$ 4.2388	$ 720,590	$ 3.8580	$ 655,860	$ 3.8902	$ 655,860	$ -	$ 0.2300	$ 39,100	$ 694,960
Total	89	100.0%	89	890,000	$ 4.2388	$ 3,772,500	$ 3.8580	$ 3,433,620	$ 3.7060	$ 3,433,620	$ -	$ 0.2300	$ 204,700	$ 3,638,320

Dec-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	06/27/14		25	250,000	$ 5.0000	$ 1,250,000	$ 3.9390	$ 984,750	$ 3.9390	$ 984,750	$ -	$ 0.2380	$ 59,500	$ 1,044,250
2	07/28/14		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2230	$ 57,980	$ 1,082,120
3	08/14/14		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2305	$ 59,930	$ 1,084,070
4	9/xx/2014		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2305	$ 59,930	$ 1,084,070
5	10/xx/2014		27	270,000	$ 4.0000	$ 1,080,000	$ 3.9390	$ 1,063,530	$ 3.9390	$ 1,063,530	$ -	$ 0.2305	$ 62,235	$ 1,125,765
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			130	1,300,000		$ 5,450,000		$ 5,120,700		$ 5,120,700	$ -		$ 299,575	$ 5,420,275
						$ 4.1923		$ 3.9390		$ 3.9390	$ -		$ 0.0550	$ 4.1694
NNG-Cons	104	80.00%	104	1,040,000	$ 4.1923	$ 4,360,000	$ 3.9390	$ 4,096,560	$ 3.9390	$ 4,096,560	$ -	$ 0.2304	$ 239,660	$ 4,336,220
Other-Cons	26	20.00%	26	260,000	$ 4.1923	$ 1,090,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2304	$ 59,915	$ 1,084,055
Total	130	100.0%	130	1,300,000	$ 4.1923	$ 5,450,000	$ 3.9390	$ 5,120,700	$ 3.7060	$ 5,120,700	$ -	$ 0.2304	$ 299,575	$ 5,420,275

Jan-15

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	06/23/14		30	300,000	$ 4.7500	$ 1,425,000	$ 4.0110	$ 1,203,300	$ 4.0110	$ 1,203,300	$ -	$ 0.3450	$ 103,500	$ 1,306,800
2	07/24/14		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2370	$ 73,470	$ 1,316,880
3	8/xx/2014		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2910	$ 90,210	$ 1,333,620
4	9/xx/2014		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2910	$ 90,210	$ 1,333,620
5	10/xx/2014		32	320,000	$ 4.2500	$ 1,360,000	$ 4.0110	$ 1,283,520	$ 4.0110	$ 1,283,520	$ -	$ 0.2910	$ 93,120	$ 1,376,640
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total	Total		155	1,550,000		$ 6,737,500		$ 6,217,050		$ 6,217,050	$ -		$ 450,510	$ 6,667,560
						$ 4.3468		$ 4.0110		$ 4.0110	$ -		$ 0.0669	$ 4.3017
NNG-Cons	126	81.29%	126	1,260,000	$ 4.3468	$ 5,476,935	$ 4.0110	$ 5,053,860	$ 4.0110	$ 5,053,860	$ -	$ 0.2907	$ 366,221	$ 5,420,081
Other-Cons	29	18.71%	29	290,000	$ 4.3468	$ 1,260,565	$ 4.0110	$ 1,163,190	$ 4.0110	$ 1,163,190	$ -	$ 0.2907	$ 84,289	$ 1,247,479
Total	155	100.0%	155	1,550,000	$ 4.3468	$ 6,737,500	$ 4.0110	$ 6,217,050	$ 3.7060	$ 6,217,050	$ -	$ 0.2907	$ 450,510	$ 6,667,560

Feb-15

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	06/18/14		28	280,000	$ 5.0000	$ 1,400,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3750	$ 105,000	$ 1,225,280
2	07/18/14		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3050	$ 85,400	$ 1,205,680
3	8/xx/2014		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3400	$ 95,200	$ 1,215,480
4	9/xx/2014		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3400	$ 95,200	$ 1,215,480
5	10/xx/2014		29	290,000	$ 4.2500	$ 1,232,500	$ 4.0010	$ 1,160,290	$ 4.0010	$ 1,160,290	$ -	$ 0.3400	$ 98,600	$ 1,258,890
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			141	1,410,000		$ 6,202,500		$ 5,641,410		$ 5,641,410	$ -		$ 479,400	$ 6,120,810
						$ 4.3989		$ 4.0010		$ 4.0010	$ -		$ 0.0773	$ 4.3410
NNG-Cons	115	81.56%	115	1,150,000	$ 4.3989	$ 5,058,777	$ 4.0010	$ 4,601,150	$ 3.6613	$ 4,601,150	$ -	$ 0.3400	$ 391,000	$ 4,992,150
Other-Cons	26	18.44%	26	260,000	$ 4.3989	$ 1,143,723	$ 4.0010	$ 1,040,260	$ 3.8902	$ 1,040,260	$ -	$ 0.3400	$ 88,400	$ 1,128,660
Total	141	100.0%	141	1,410,000	$ 4.3989	$ 6,202,500	$ 4.0010	$ 5,641,410	$ 3.7060	$ 5,641,410	$ -	$ 0.3400	$ 479,400	$ 6,120,810

Mar-15

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	06/10/14		23	230,000	$ 4.7500	$ 1,092,500	$ 3.8690	$ 889,870	$ 3.8690	$ 889,870	$ -	$ 0.3960	$ 91,080	$ 980,950
2	07/08/14		24	240,000	$ 4.2500	$ 1,020,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4110	$ 98,640	$ 1,027,200
3	8/xx/2014		24	240,000	$ 4.0000	$ 960,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4035	$ 96,840	$ 1,025,400
4	9/xx/2014		24	240,000	$ 4.0000	$ 960,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4035	$ 96,840	$ 1,025,400
5	10/xx/2014		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8690	$ 967,250	$ 3.8690	$ 967,250	$ -	$ 0.4035	$ 100,875	$ 1,068,125
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			120	1,200,000		$ 5,032,500		$ 4,642,800		$ 4,642,800	$ -		$ 484,275	$ 5,127,075
						$ 4.1938		$ 3.8690		$ 3.8690	$ -		$ 0.0962	$ 4.2726
NNG-Cons	96	80.00%	96	960,000	$ 4.1938	$ 4,026,000	$ 3.8690	$ 3,714,240	$ 3.6613	$ 3,714,240	$ -	$ 0.4036	$ 387,420	$ 4,101,660
Other-Cons	24	20.00%	24	240,000	$ 4.1938	$ 1,006,500	$ 3.8690	$ 928,560	$ 3.8902	$ 928,560	$ -	$ 0.4036	$ 96,855	$ 1,025,415
Total	120	100.0%	120	1,200,000	$ 4.1938	$ 5,032,500	$ 3.8690	$ 4,642,800	$ 3.7060	$ 4,642,800	$ -	$ 0.4036	$ 484,275	$ 5,127,075

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			123	1,230,000	$ 4.8923	$ 6,017,500	$ 3.9464	$ 4,854,060	19.678	$ 4,854,060	$ -	$ 0.3248	$ 399,540	$ 5,253,600
2			126	1,260,000	$ 4.1984	$ 5,290,000	$ 3.9462	$ 4,972,250	19.678	$ 4,972,250	$ -	$ 0.2803	$ 353,230	$ 5,325,480
3			126	1,260,000	$ 4.1171	$ 5,187,500	$ 3.9462	$ 4,972,250	19.678	$ 4,972,250	$ -	$ 0.3026	$ 381,280	$ 5,353,530
4			128	1,280,000	$ 4.1152	$ 5,267,500	$ 3.9449	$ 5,049,410	19.678	$ 5,049,410	$ -	$ 0.3015	$ 385,880	$ 5,435,290
5			132	1,320,000	$ 4.1155	$ 5,432,500	$ 3.9452	$ 5,207,610	19.678	$ 5,207,610	$ -	$ 0.3019	$ 398,530	$ 5,606,140
6														
7														
8														
9														
10														
11														
12														
13														
14														
15														
Total			635	6,350,000		$ 27,195,000		$ 25,055,580		$ 25,055,580	$ -		$ 1,918,460	$ 26,974,040
						$ 4.2827		$ 3.9458		$ 3.9458	$ -		$ 0.0705	$ 4.2479
NNG-Cons	513	80.79%	513	5,130,000	$ 4.2834	$ 21,973,622	$ 3.9461	$ 20,243,570	18.9340482	$ 20,243,570	$ -	$ 0.3021	$ 1,549,901	$ 21,793,471
Other-Cons	122	19.21%	122	1,220,000	$ 4.2798	$ 5,221,378	$ 3.9443	$ 4,812,010	19.6205512	$ 4,812,010	$ -	$ 0.3021	$ 368,559	$ 5,180,569
Total	635	100.0%	635	6,350,000	$ 4.2827	$ 27,195,000	$ 3.9458	$ 25,055,580	$ 3.7060	$ 25,055,580	$ -	$ 0.3021	$ 1,918,460	$ 26,974,040

ATTACHMENT 4

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Kristin M. Stastny hereby certifies that on the 1st day of August, 2014, 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, 2014.

/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	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 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
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th Street West Rosemount, MN 55068	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@stinsonleonard.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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

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	OFF_SL_13-617_Official cc 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	Yes	OFF_SL_13-617_Official cc service list
Seth	DeMerritt	ssdemerritt@integrysgroup.com	Integrys Business Support	700 North Adams P.O. Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_13-617_Official cc service list
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-617_Official cc 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	Yes	OFF_SL_13-617_Official cc service list
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-617_Official cc service list
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_13-617_Official cc service list
Harry W	John	HWJohn@integrysgroup.com	MERC, Integrys	700 North Adams PO Box 19001 Green Bay, WI 54307-9001	Electronic Service	No	OFF_SL_13-617_Official cc service list
David G.	Kult	dgkult@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St. NW Rosemount, MN 55068	Electronic Service	No	OFF_SL_13-617_Official cc service list
David	Kyto	djkyto@integrysgroup.com	Integrys Business Support	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_13-617_Official cc service list

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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	Yes	OFF_SL_13-617_Official cc service list
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_13-617_Official cc service list
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_13-617_Official cc service list
Chad T	Marriott	ctmarriott@stoel.com	Stoel Rives LLP	900 SW 5th Ave Ste 2600 Portland, OR 97204	Electronic Service	No	OFF_SL_13-617_Official cc service list
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-617_Official cc service list
Barbara	Nick	banick@integrysgroup.com	Minnesota Energy Resources Corporation	2665 145th Street PO Box 455 Rosemount, MN 55068-0455	Electronic Service	No	OFF_SL_13-617_Official cc service list
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_13-617_Official cc service list
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_13-617_Official cc service list
Kristin	Stastny	stastny.kristin@dorsey.com	Dorsey & Whitney LLP	50 South 6th Street Suite 1500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-617_Official cc service list
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_13-617_Official cc service list

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James P.	Zakoura	Jim@smizak-law.com	Smithyman & Zakoura Chartered	750 Commerce Plaza II 7400 West 110th Street Overland Park, KS 662102362	Electronic Service	No	OFF_SL_13-617_Official cc service list

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2014
NNG

Design Day Requirement		245,878
Total Peak Day Entitlement		256,385
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 6)	212,806
Firm Annual Throughput - Minnesota		21,803,847
No. of Firm Customers		178,388
Department Load Factor Calculation		28.07%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2014

NNG

Pipeline Group	Nov13-Mar 14 Avg. Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors		Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	Nov13-Mar 14 Avg. Customer Growth	Total *
				Intercept	Slope					
PEAK										
NNG	178,388	178,388	100	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
Total	178,388	178,388								245,783
OFF PEAK										
NNG	178,388	178,388	55	41,361	2,341	182,893	27,735	155,158	0.60%	156,089
Total	178,388	178,388								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% confiden
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, 2014

		NNG	
Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
14/15	178,388	245,878	1.38
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

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2015

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	5,975,516	15,812,613	21,788,129
SVI	1,408,810	1,257,722	2,666,533
SVJ	6,017	9,702	15,718
LVI			0
LVJ	0	0	0
SLV	0	0	0
Total	7,390,343	17,080,037	24,470,380

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2014

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
TF-12 Base & Variable	76,079	0	76,079
TF5	31,515	0	31,515
TFX - 12	32,297	0	32,297
TFX - 5	93,084	0	93,084
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	20,000	0	20,000
Heating Season Total	**256,385**	**0**	**256,385**
Non-Heating Season Total	113,786	0	113,786
Heating Season Forecasted Design Day-Adjusted	245,878	0	245,878
Non-Heating Season Forecasted Design Day	156,089	(0)	156,089
Heating Season Capacity Surplus/Shortage	10,507	0	10,507
Non-Heating Season Capacity Surplus/Shortage	(42,303)	0	(42,303)

*Not included in Heating Season Total entitlement

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2014
NNG

All costs in $/Dth	Last Base Cost of Gas G011/ MR13-732* Jan. 14	Last Demand Change G011-12-1193 Jul. 13	Last Demand Change G011-13-670 Nov. 13	Most Recent PGA Aug. 14	Current Proposal Effective Nov.1,2014	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:		**93**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$1.7955	$1.6968	$1.7177	$1.7822	$1.7920	($0.0035)	$0.0743	0.55%	$0.0098
Commodity Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	$0.0000	$0.2536	0.00%	$0.0000
Total Cost of Gas	$8.5880	$7.5547	$7.7406	$8.0562	$8.0779	($0.5101)	$0.3373	0.27%	$0.0217
Avg Annual Cost	$798.68	$702.59	$719.88	$749.23	$751.24	($47.44)	$31.37	0.27%	$2.02
Effect of proposed commodity change on average annual bills:									$1.11
Effect of proposed demand change on average annual bills:									$0.91
2) Small Vol. Interruptible: Avg. Annual Use:		**6,699**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost									
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	($0.5066)	$0.1461	0.23%	$0.0119
Avg Annual Cost	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$35,225.35	($3,393.71)	$978.72	0.23%	$79.72
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**42,000**		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost									
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	($0.5066)	$0.0552	0.27%	$0.0119
Avg Annual Cost	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$187,299.00	($21,277.20)	$2,318.40	0.27%	$499.80
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**6,699**		**Dth**					
		25		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	$0.1663	$0.1663	0.82%	$0.1548
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	($0.5066)	$0.1461	0.23%	$0.0119
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	$0.1663	$0.4616	0.72%	$0.1548
Avg Annual Cost	$39,155.94	$33,684.14	$34,776.12	$35,682.79	$35,766.38	($3,389.56)	$990.26	0.23%	$83.59
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$3.87
5) Large Vol. Firm: Avg. Annual Use:		**42,000**		**Dth**					
		75		**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	($0.5066)	$0.0094	0.29%	$0.0119
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	$0.1663	$0.1663	0.82%	$0.1548
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	($0.5066)	$0.0552	0.27%	$0.0119
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	$0.1663	$0.4616	0.72%	$0.1548
Avg Annual Cost	$210,186.82	$179,679.15	$186,569.07	$188,410.68	$188,922.09	($3,389.56)	$2,353.02	0.27%	$511.41
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$11.61

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-13-600
*As approved in Docket No. G011/MR-13-732; to coincide with implementation of interim rates in Docket No. G011/GR-13-617

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2014

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-14**

		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	112495	$5.6830	$10.2300	$7.5171	$0.0000	$7.5171
TF-12B Discount	112495	$5.6830	$10.0320	$7.4951	$0.0000	$7.4951
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						$3.9655

V. ANNUAL SALES -- As approved in Docket No. G011/MR-13-732 234,442,025 Therms
Total MERC NNG Annual Sales

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-14**

		Contract #(s)	Monthly Entitlement (Dth)	Months	Rate $/Dth		Contract Costs	Rate/Therm
A. GS	TF12B (Max Rate) Winter	112495	43,953	5	$10.2300	=	$2,248,196	$0.01046
	TF12B (Max Rate) Summ	112495	43,190	7	$5.6830	=	$1,718,141	$0.00799
	TF12V (Max Rate)	112495	26,926	12	$9.0926	=	$2,937,928	$0.01366
	TF5 (Max Rate)	112495	31,515	5	$15.1530	=	$2,387,734	$0.01110
	TF12B (Discount-Winter)	112495	5,200	12	$7.4951	=	$467,694	$0.00218
	TFX5 (Discount)	112561	0	5	$4.5600	=	$0	$0.00000
	TFX12 (Max Rate)	112486	10,822	12	$9.6288	=	$1,250,434	$0.00582
	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	66,271	5	$15.1530	=	$5,021,022	$0.02335
	TFX5 (Discount)	112486	1,800	5	$7.6000	=	$68,400	$0.00032
	TFX12 (Discount)	111866	1,283	12	$4.8640	=	$74,886	$0.00035
	TFX12 (Discount)	111866	8,271	12	$5.4720	=	$543,107	$0.00253
	TFX12 (Discount)	111866	11,921	12	$7.6025	=	$1,087,553	$0.00506
	TFX5 (Discount)	111866	379	5	$4.8640	=	$9,217	$0.00004
	TFX5 (Discount)	111866	2,445	5	$5.4720	=	$66,895	$0.00031
	TFX5 (Discount)	111866	22,189	5	$15.1392	=	$1,679,619	$0.00781
	Bison	FT0003	50,000	12	$17.4896	=	$10,493,750	$0.04880
	NBPL	T8673F	50,000	12	$6.9958	=	$4,197,500	$0.01952
	Windom		2,500	12	$0.0000	=	$0	$0.00000
	Ortonville		910	12	$8.0000	=	$87,360	$0.00041
	NNG Zone GDD Call Option		20,000	3	$0.9000	=	$54,000	$0.00025
FDD:	Storage Reservation	118657	75,437	12	$1.7140	=	$1,551,588	$0.00722
	Storage Cycle Volume	118657	869,864	5	$0.3567	=	$1,551,402	$0.00722
	Storage Reservation	118657	5,550	12	$3.3157	=	$220,826	$0.00103
	Storage Cycle Volume	118657	64,000	5	$0.6901	=	$220,832	$0.00103
	Storage Reservation	125915	2,602	12	$1.7140	=	$53,518	$0.00025
	Storage Cycle Volume	125915	30,000	5	$0.3567	=	$53,505	$0.00025
	Storage Reservation	125916	11,274	12	$1.7140	=	$231,884	$0.00108
	Storage Cycle Volume	125916	130,000	5	$0.3567	=	$231,855	$0.00108
	Total Demand Cost						$38,531,579	$0.17705

Rate Case volume as approved in Docket No. G0011/MR-13-732 in therms	215,014,955	
NNG-GS Demand Current Cost of Gas/therm		**$0.17920**
NNG-GS Commodity Current Cost of Gas/therm+		**$0.40569**
Total NNG-GS Current Cost of Gas/therm		**$0.58489**

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	23,444,203	x	$3.9655	$92,967,985.01	234,442,025	$0.39655
SMS-Bal Service	272,160	x	$2.1800	$593,309	234,442,025	$0.00253
Call Option Premium				$ 1,549,901	234,442,025	$0.00661
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$ 95,111,195	234,442,025	$0.40569

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2014

NNG

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Months	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate) Winter	43,953	112495	5	$10.2300	=	$2,248,196	$0.11113
TF12B (Max Rate) Summer	43,190	112495	7	$5.6830	=	$1,718,141	$0.08493
TF12V (Max Rate)	26,926	112495	12	$9.0926	=	$2,937,928	$0.14522
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.11802
TF12B (Discount-Winter)	5,200	112495	12	$7.4951	=	$467,694	$0.02312
TFX5 (Discount)	0	112561	5	$4.5600	=	$0	$0.00000
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06181
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)	66,271	112486	5	$15.1530	=	$5,021,022	$0.24819
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00338
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00370
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02685
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05376
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00046
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00331
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08302
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.51870
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	$0.20748
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00432
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00267
Storage Reservation	75,437	118657	12	$1.7140	=	$1,551,588	$0.07669
Storage Cycle Volume	869,864	118657	5	$0.3567	=	$1,551,402	$0.07668
Storage Reservation	5,550	118657	12	$3.3157	=	$220,826	$0.01092
Storage Cycle Volume	64,000	118657	5	$0.6901	=	$220,832	$0.01092
Storage Reservation	2,602	125915	12	$1.7140	=	$53,518	$0.00265
Storage Cycle Volume	30,000	125915	5	$0.3567	=	$53,505	$0.00264
Storage Reservation	11,274	125916	12	$1.7140	=	$231,884	$0.01146
Storage Cycle Volume	130,000	125916	5	$0.3567	=	$231,855	$0.01146
				TOTAL		$38,531,578	
				Annualized Entitlement		20,230,860	
				Demand Component		$1.90459	$1.90459

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, 2014

NNG

All costs in $/Dth	Last Base Cost of Gas G011/ MR13-732* Jan. 14	Last Demand Change G011- 12-1193 Jul. 13	Last Demand Change G011- 13-977 Nov. 13	Most Recent PGA Aug. 14	Current Proposal Effective Nov.1,2014	Result of Proposed Change: Change from Last Rate Case**	Result of Proposed Change: Change from Last Demand Change	Result of Proposed Change: Change from Last PGA %	Result of Proposed Change: Change from Last PGA $
1) General Service Residential: Avg. Annua	**93**			**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$1.7955	$1.6968	$1.7177	$1.7822	$1.6006	($0.1949)	($0.1171)	-10.19%	($0.1816)
Commodity Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	$0.0000	$0.2536	0.00%	$0.0000
Total Cost of Gas	$8.5880	$7.5547	$7.7406	$8.0562	$8.0621	($0.5259)	$0.3215	0.07%	$0.0059
Avg Annual Cost	$798.68	$702.59	$719.88	$749.23	$749.78	($48.91)	$29.90	0.07%	$0.55
Effect of proposed commodity change on average annual bills:									$17.43
Effect of proposed demand change on average annual bills:									($16.89)
2) Small Vol. Interruptible: Avg. Annual Use	**6,699**			**Dth**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost									
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	($0.3310)	$0.3217	3.57%	$0.1875
Avg Annual Cost	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$36,401.42	($2,217.65)	$2,154.79	3.57%	$1,255.78
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:	**42,000**			**Dth**		0			
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost									
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	($0.3310)	$0.2308	4.21%	$0.1875
Avg Annual Cost	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$194,672.44	($13,903.76)	$9,691.84	4.21%	$7,873.24
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**6,699**		**Dth**					
		25		**DTh**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	$0.0000	($1.3265)	-7.08%	($1.3380)
Commodity Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	$0.0000	$0.1367	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$2.5953	$0.2953	0.00%	$0.0000
Total Cost of Gas	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	($0.3310)	$0.3217	3.57%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	($1.3265)	($1.0312)	-6.23%	($1.3380)
Avg Annual Cost	$39,155.94	$33,684.14	$34,776.12	$35,682.79	$36,905.13	($2,250.81)	$2,129.01	3.43%	$1,222.33
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									($33.45)
5) Large Vol. Firm: Avg. Annual Use:		**42,000**		**Dth**					
		75		**DTh**					
Commodity Cost	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	($0.3310)	$0.1850	4.63%	$0.1875
Demand Cost	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	($1.3265)	($1.3265)	-7.08%	($1.3380)
Commodity Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	$0.0000	$0.0458	0.00%	$0.0000
Demand Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	$0.0000	$0.2953	0.00%	$0.0000
Total Cost of Gas	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	($0.3310)	$0.2308	4.21%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	$20.1484	($1.0312)	-6.23%	($1.3380)
Avg Annual Cost	$210,186.82	$179,679.15	$186,569.07	$188,410.68	$196,183.57	($1,713.94)	$9,614.50	4.13%	$7,772.89
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									($100.35)

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-13-600

*As approved in Docket No. G011/MR-13-732; to coincide with implementation of interim rates in Docket No. G011/GR-13-617

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, 2014

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IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-14**

		Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	112495	5.683	10.23	$7.5776	$0.0000	$7.5776
TF-12B Discount	112495	5.683	10.032	$7.4951	$0.0000	$7.4951
TF-12V	112495	5.683	13.866	$9.0926	$0.0000	$9.0926
TF-5	112495	0	15.153	$6.3138	$0.0000	$6.3138
TFX	112486	5.683	15.153	$9.6288	$0.0000	$9.6288
TFX-5	112486	0	15.153	$6.3138	$0.0000	$6.3138
TFX-5 Discount	112486	0	7.6	$3.1667	$0.0000	$3.1667
TFX - Discount	111866	7.6025	0	$4.4348	$0.0000	$4.4348
TFX - Discount	111866	15.1392	0	$8.8312	$0.0000	$8.8312
TFX - Discount	111866	5.472	5.472	$5.4720	$0.0000	$5.4720
TFX - Discount	111866	4.864	4.864	$4.8640	$0.0000	$4.8640
Gas Cost						$3.9655

V. ANNUAL SALES -- As approved in Docket No. G011/MR-13-732 234,442,025

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-14**

		Contract #(s)		Months				Rate/CCF
A. GS	TF12B (Max Rate) Winter	112,495	43,953	5	10	=	$2,248,196	$0.01046
	TF12B (Max Rate) Summ	112,495	43,190	7	6	=	$1,718,141	$0.00799
	TF12V (Max Rate)	112,495	26,926	12	9	=	$2,937,928	$0.01366
	TF5 (Max Rate)	112,495	31,515	5	15	=	$2,387,734	$0.01110
	TF12B (Discount-Winter)	112,495	5,200	12	7	=	$467,694	$0.00218
	TFX5 (Discount)	112,561	0	5	5	=	$0	$0.00000
	TFX12 (Max Rate)	112,486	10,822	12	10	=	$1,250,434	$0.00582
	TFX Apr (Max Rate)	112,486	2,000	1	6	=	$11,366	$0.00005
	TFX Oct (Max Rate)	112,486	2,000	1	6	=	$11,366	$0.00005
	TFX5 (Max Rate)	112,486	66,271	5	15	=	$5,021,022	$0.02335
	TFX5 (Discount)	112,486	1,800	5	8	=	$68,400	$0.00032
	TFX12 (Discount)	111,866	1,283	12	5	=	$74,886	$0.00035
	TFX12 (Discount)	111,866	8,271	12	5	=	$543,107	$0.00253
	TFX12 (Discount)	111,866	11,921	12	8	=	$1,087,553	$0.00506
	TFX5 (Discount)	111,866	379	5	5	=	$9,217	$0.00004
	TFX5 (Discount)	111,866	2,445	5	5	=	$66,895	$0.00031
	TFX5 (Discount)	111,866	22,189	5	15	=	$1,679,619	$0.00781
	Bison	FT0003	50,000	12	17	=	$10,493,750	$0.04880
	NBPL	T8673F	50,000	12	7	=	$4,197,500	$0.01952
	Windom	0	2,500	12	0	=	$0	$0.00000
	Ortonville	0	910	12	8	=	$87,360	$0.00041
	NNG Zone GDD Call Opti	0	20,000	3	1	=	$54,000	$0.00025
	Total Demand Cost						$34,416,168	**$0.16006**
	Rate Case volume as approved in Docket No. G0011/MR-13-732 in therms						215,014,955	
	GS-1 Demand Current Cost of Gas/Ccf							**$0.16006**
	GS-1 Commodity Current Cost of Gas/Ccf							**$0.42325**
	Total GS-1 Current Cost of Gas/Ccf							**$0.58331**

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	2	=	$1,551,588	$0.00662
	FDD - Storage Cycle	118657	869,864	5	0	=	$1,551,402	$0.00662
	FDD - Reservation	118657	5,550	12	3	=	$220,826	$0.00094
	FDD - Storage Cycle	118657	64,000	5	1	=	$220,832	$0.00094
	FDD - Reservation	125915	2,602	12	2	=	$53,518	$0.00023
	FDD - Storage Cycle	125915	30,000	5	0	=	$53,505	$0.00023
	FDD - Reservation	125916	11,274	12	2	=	$231,884	$0.00099
	FDD - Storage Cycle	125916	130,000	5	0	=	$231,855	$0.00099
	Firm Deferred Delivery Storage Contracts						$4,115,410	$0.01755

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	23,444,203	x	$3.9655	$92,967,985	234,442,025	$0.39655
SMS-Bal Service	272,160	x	$2.1800	$593,309	234,442,025	$0.00253
Call Option Premium				$1,549,901	234,442,025	$0.00661
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$99,226,605	234,442,025	**$0.42325**

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, 2014

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COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	Cost/Unit		Cost	$/Ccf
TF12B (Max Rate) Winter	43,953	112495	5	$10.2300	=	$2,248,196	$0.11466
TF12B (Max Rate) Summer	43,190	112495	7	$5.6830	=	$1,718,141	$0.08763
TF12V (Max Rate)	26,926	112495	12	$9.0926	=	$2,937,928	$0.14984
TF5 (Max Rate)	31,515	112495	5	$15.1530	=	$2,387,734	$0.12178
TF12B (Discount-Winter)	5,200	112495	12	$7.4951	=	$467,694	$0.02385
TFX5 (Discount)	0	112561	5	$4.5600	=	$0	$0.00000
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.06378
TFX Apr (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00058
TFX Oct (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00058
TFX5 (Max Rate)	66,271	112486	5	$15.1530	=	$5,021,022	$0.25608
TFX5 (Discount)	1,800	112486	5	$7.6000	=	$68,400	$0.00349
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00382
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02770
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.05547
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00047
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00341
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.08566
Bison	50,000	FT0003	12	$17.4896	=	$10,493,750	$0.53521
NBPL	50,000	T8673F	12	$6.9958	=	$4,197,500	$0.21408
Windom	2,500		12	$0.0000	=	$0	$0.00000
Ortonville	910		12	$8.0000	=	$87,360	$0.00446
NNG Zone GDD Call Option	20,000		3	$0.9000	=	$54,000	$0.00275
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	2,602	125915	0	$1.7140	=	$0	$0.00000
Storage Cycle Volume	30,000	125915	0	$0.3567	=	$0	$0.00000
Storage Reservation	11,274	125916	0	$1.7140	=	$0	$0.00000
				TOTAL		$34,416,169	
				Annualized Entitlement		19,606,860	
				Demand Component		$1.75531	$1.75531

MINNESOTA ENERGY RESOURCES - NNG

NNG Entitlement Allocation

Heating Season 2014-2015

		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**	**235,475**	**235,475**
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)**
		231,970	**231,970**
	Direct Assigned Entitlement		
11	**TF12B (112495)**	49,153	**49,153**
12	**TF12V (112495)**	26,926	**26,926**
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)**	68,071	**68,071**
18	**TFX12 (111866)**	21,475	**21,475**
19	**TFX5 (111866)**	25,013	**25,013**
20	**TFX5 (112561)**	0	**-**
21	**Bison (FT 0003) ***	50,000	**50,000**
22	**NBPL (T6873F) ***	50,000	**50,000**
23	**Total Winter Allocated Entitlement**	232,975	**232,975**
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**	**256,385**	**256,385**
29	**Contract Demand**		
30	**Total Design Day Capacity**	**256,385**	**256,385**
			100.00%
31	**Storage**		
32	**Storage MSQ - 118657**	4,669,321	**4,669,321**
33	**Storage MSQ -125915**	150,000	**150,000**
34	**Storage MSQ - 125916**	650,000	**650,000**
35	**SMS**	22,680	**22,680**
36	**Total Entitlement**	256,385	**256,385**
37	**Design Day**	245,878	**245,878**
38	**Reserve Margin**	10,507	**10,507**
		4.27%	4.27%

***** 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

2014-2015

State	1/20 Design DDD	13/14 Customer Counts*	Regression Factors Intercept	Regression Factors Slope	Regression Total	Adjustment Total *	1/20 Requirements Regression Load	Nov13-Mar14 Customer Growth	Total
MERC - Peak Day									
NNG	100	178,388	41,361	2,341	287,358	43,041	244,317	0.60%	245,783
TOTAL	**100**	**178,388**	**41,361**	**2,341**	**287,358**	**43,041**	**244,317**		**245,783**

Attachment 7

MINNESOTA ENERGY RESOURCES-PNG/NMU CAPACITY RESOURCE ANALYSIS

2014-2015 VS. 2013-2014

	2014-2015 Proposed		2013-2014		Difference	
	NNG	NNG	NNG	NNG		
	Winter	**Total**	**Winter**	**Total**	**Winter**	**Total**
TF12(base)	49,153	49,153	49,153	49,153	-	-
TF12(variable)	26,926	26,926	26,926	26,926	-	-
TF12	76,079	76,079	76,079	76,079	-	-
Peak Capacity	-	-	-	-	-	-
TF5	31,515	31,515	31,515	31,515	-	-
TF Total	107,594	107,594	107,594	107,594	-	-
TFX12	32,297	32,297	32,297	32,297	-	-
TFX5	93,084	93,084	93,084	93,084	-	-
TFX Total	125,381	125,381	125,381	125,381	-	-
NNG Total	232,975	232,975	232,975	232,975	-	-
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	256,385	256,385	256,385	256,385	-	-

	NNG-Total EF
Design Day	245,878
Capacity	256,385
Reserve Margin	10,507
	4.27%

Attachment 8

MINNESOTA ENERGY RESOURCES - NNG

Financial Options

Heating Season 2014-2015

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	$16,800			$ 0	$ 54,000

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	06/25/14	2,718	06/16/14	114	06/11/14	224	06/30/14	1,272	06/20/14	1,243	5,572	166,187
2	07/25/14	2,966	06/16/14	228	06/11/14	1,567	07/30/14	1,484	06/20/14	1,243	7,488	224,700
3	08/xx/14	2,966	07/16/14	455	07/10/14	448	8/xx/2014	1,484	06/20/14	1,243	6,596	197,065
4	09/xx14	2,966	8/xx/2014	455	07/10/14	2,014	9/xx/2014	1,272	06/20/14	1,243	7,951	239,699
5	10/xx14	2,718	9/xx/2014	342	8/xx/2014	2,238	10/xx/2014	1,272	07/21/14	4,973	11,544	351,319
6			10/xx/2014	342	9/xx/2014	2,238			8/xx/2014	4,724	7,304	226,434
7					10/xx/2014	2,238			9/xx/2014	4,724	6,963	215,846
8									10/xx/2014	4,476	4,476	138,750
9											-	-
10											-	-
Total		14,333		1,935		10,968		6,786		23,871	57,893	1,760,000
		430,000		60,000		340,000		190,000		740,000		1,760,000
		#REF!		#REF!		#REF!		#REF!		#REF!		#REF!

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	06/13/14	4,584	06/27/14	6,452	06/23/14	7,867	06/18/14	8,156	06/10/14	5,935	32,994	993,768
2	07/14/14	4,584	07/28/14	6,710	07/24/14	8,129	07/18/14	8,156	07/08/14	6,194	33,773	1,017,897
3	8/xx/2014	4,584	08/14/14	6,710	8/xx/2014	8,129	8/xx/2014	8,156	8/xx/2014	6,194	33,773	1,017,897
4	9/xx/2014	5,124	9/xx/2014	6,710	9/xx/2014	8,129	9/xx/2014	8,156	9/xx/2014	6,194	34,312	1,034,077
5	10/xx/2014	5,124	10/xx/2014	6,968	10/xx/2014	8,391	10/xx/2014	8,447	10/xx/2014	6,452	35,382	1,066,362
6												
7												
Total		24,000		33,548		40,645		41,071		30,968	170,233	5,130,000
		720,000		1,040,000		1,260,000		1,150,000		960,000		5,130,000
		#REF!		#REF!		#REF!		#REF!		#REF!		#REF!

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	$ 0.2380	$ 32,732	$ 0.2380	$47,600	$ 0.3450	$84,135	$ 0.3750	$85,638	$ 0.3960	$ 72,864	$ 0.3250	$ 322,969
2	$ 0.2220	$ 30,531	$ 0.2230	$46,384	$ 0.2370	$59,724	$ 0.3050	$69,652	$ 0.4110	$ 78,912	$ 0.2802	$ 285,204
3	$ 0.2300	$ 31,631	$ 0.2305	$47,944	$ 0.2910	$73,332	$ 0.3400	$77,645	$ 0.4035	$ 77,472	$ 0.3026	$ 308,025
4	$ 0.2300	$ 35,353	$ 0.2305	$47,944	$ 0.2910	$73,332	$ 0.3400	$77,645	$ 0.4035	$ 77,472	$ 0.3026	$ 311,746
5	$ 0.2300	$ 35,353	$ 0.2305	$49,788	$ 0.2910	$75,698	$ 0.3400	$80,418	$ 0.4035	$ 80,700	$ 0.3026	$ 321,957
6												
7												
Total	**$ 0.2300**	**$ 165,600**	**$ 0.2304**	**$ 239,660**	**$ 0.2907**	**$ 366,221**	**$ 0.3400**	**$ 391,000**	**$ 0.4036**	**$ 387,420**	**$ 0.3021**	**$ 1,549,901**
		#REF!		**#REF!**		**#REF!**		**#REF!**		**#REF!**		**#REF!**

Units - Collar Floor (put)

No Puts were purchased.

14/15 Winter Portfolio Plan - MERC NNG Consolidated Hedging Plan

10,000 Contract Size

REVISED: 7/1/2014

		Nov-14		Dec-14		Jan-15		Feb-15		Mar-15		Total		Percent
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	of Requirements
MN Requirements			2,404,840		3,483,485		4,187,889		3,826,379		3,177,443		17,080,036	17,080,036
NNG -MN			80,161		112,370		135,093		136,656		102,498		113,113	
70%			1,683,388		2,438,440		2,931,522		2,678,465		2,224,210		11,956,025	
40%			961,936		1,393,394		1,675,156		1,530,552		1,270,977		6,832,014	
			533,259		1,339,984		1,339,984		1,339,984		533,259		5,086,470	
			428,677		53,410		335,172		190,568		737,718		1,745,544	
30%			721,452	0	1,045,046	0	1,256,367	0	1,147,914	0	953,233		5,124,011	
Contracts	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	May-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	8	80,000	0	0	5	50,000	3	30,000	15	150,000	31	310,000	
	Jul-14	9	90,000	2	20,000	8	80,000	4	40,000	15	150,000	38	380,000	
	Aug-14	9	90,000	2	20,000	7	70,000	4	40,000	15	150,000	37	370,000	
	Sep-14	9	90,000	1	10,000	7	70,000	4	40,000	15	150,000	36	360,000	
	Oct-14	8	80,000	1	10,000	7	70,000	4	40,000	14	140,000	34	340,000	
	Total	**43**	**430,000**	**6**	**60,000**	**34**	**340,000**	**19**	**190,000**	**74**	**740,000**	**176**	**1,760,000**	**10.30%**
Call Options	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	May-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	14	140,000	20	200,000	25	250,000	23	230,000	19	190,000	101	1,010,000	
	Jul-14	14	140,000	21	210,000	25	250,000	23	230,000	19	190,000	102	1,020,000	
	Aug-14	14	140,000	21	210,000	25	250,000	23	230,000	19	190,000	102	1,020,000	
	Sep-14	15	150,000	21	210,000	25	250,000	23	230,000	19	190,000	103	1,030,000	
	Oct-14	15	150,000	21	210,000	26	260,000	23	230,000	20	200,000	105	1,050,000	
	Total	**72**	**720,000**	**104**	**1,040,000**	**126**	**1,260,000**	**115**	**1,150,000**	**96**	**960,000**	**513**	**5,130,000**	**30.04%**
Collars	Feb-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-14	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-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-14	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-14	9,584	287,520	8,871	275,001	12,904	400,024	11,965	335,020	13,709	424,979	57,033	1,722,544	
	Aug-14	9,584	287,520	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,032	1,722,516	
	Sep-14	9,583	287,490	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,031	1,722,486	
	Oct-14	9,583	287,490	8,871	275,001	12,903	399,993	11,964	334,992	13,710	425,010	57,031	1,722,486	
	Total		**1,150,020**		**1,100,004**		**1,600,003**		**1,339,996**		**1,700,009**		**6,890,032**	**40.34%**
Physical Hedges			**0**		**0**		**0**		**0**		**0**		**0**	
Storage			533,259		1,339,984		1,339,984		1,339,984		533,259		5,086,470	**29.78%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			70.00%		70.04%		70.20%		70.04%		70.29%		70.12%	
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													1,760,000	**10.30%**
Call Options													5,130,000	**30.04%**
Costing Collar													0	**0.00%**
Storage													5,086,470	**29.78%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													5,103,566	**29.88%**
Total													17,080,036	**100.00%**

NOTE:

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN

NOVEMBER, 2014 THROUGH MARCH, 2015

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

(Nov–Mar columns: Daily Volumes)

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Index - Back Financial Options	TBD	TBD	NNG Ventura	590	-	13,869	10,113	17,095	1,260,748
Index - Back Financial Options	2946	1/11/2011	NNG Welcome	8,957	8,957	8,957	8,957	8,957	1,352,507
Index - Back Financial Options	TBD	TBD	NNG Welcome	7,740	5,480	7,740	7,740	7,740	1,098,680
Index - Back Financial Options	2946	1/11/2011	NNG Aberdeen	3,244	3,244	3,244	3,244	3,244	489,844
Index - Back Financial Options	TBD	TBD	NNG Beatrice	5,623	5,623	5,623	5,623	5,623	849,073
Index - Back Financial Options	2946	1/11/2011	NNG Marshall	12,180	12,180	12,180	12,180	12,180	1,839,180
	Total Actual Seasonal Index			**38,334**	**35,484**	**51,613**	**47,857**	**54,839**	**6,890,032**
GAS DAILY PACKAGES									
	TBD	TBD	MERC Zone EF	-	20,000	20,000	20,000	-	60,000

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 125915 Volume Injected	Contract # 125916 Volume Injected	Total Volume Injected
May - balance forward	79,831	0	0	79,831
June	817,150	29,760	127,770	974,680
July	964,644	30,044	131,380	1,126,068
August	946,071	30,392	131,700	1,108,163
Sept	915,553	29,412	127,451	1,072,416
Oct (est)	946,072	30,392	131,699	1,108,163
Total	**4,669,321**	**150,000**	**650,000**	**5,469,321**

MERC Attachment 10
NNG Demand Entitlements

MINNESOTA ENERGY RESOURCES - NNG

	M-10-Peoples Mn GS	M-11-Peoples Mn GS	M-12-Peoples Mn GS	**M-13-Peoples Mn GS**	**M-14-Peoples Mn GS**	Proposed Change
Design Day	194,598	211,182	200,785	**245,878**	**245,878**	0
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	35.92%	33.31%	38.29%	**28.43%**	**28.07%**	0.36%
Total Design Day Capacity (includes non-recallable capacity)	233,627	221,436	208,007	**256,385**	**256,385**	0
Less: Windom	2,500	2,500	2,500	**2,500**	**2,500**	0
Less: Northwestern Energy	0	910	910	**910**	**910**	0
Less: LS Power	25,951	0	0	**0**	**0**	0
Less: TF12B	0	0	0	**0**	**0**	0
Less: TF5						
Less: TFX(5)						
Total Design Day Capacity	205,176	218,026	204,597	**252,975**	**252,975**	48,378
Factors for All Winter Capacity	100.00%	100.00%	100.00%	**100.00%**	**100.00%**	

Allocated Entitlements in PGA	M-10-Peoples Mn GS	M-11-Peoples Mn GS	M-12-Peoples Mn GS	M-13-Peoples Mn GS	M-14-Peoples Mn GS	Proposed Change
TF12B	34,875	42,396	41,156			0
TF12V	32,290	25,298	25,820			0
TF5	28,785	29,011	28,704			0
TFX12	28,802	29,029	28,721			0
TFX(5)	80,424	81,057	80,197			0
TFX(5) (12-V)	0	0	0			0
TFX (October Only)	1,784	1,798	1,779			0
TFX (April Only)	1,784	1,798	1,779			0
NNG Zone Delivery Call Option	0	11,235	0			0
LS Power	25,951	0	0			0
Bison *	44,589	44,940	44,463			0
NBPL *	44,589	44,940	44,463			0
Peak Capacity	231,127	218,026	205,508			0
Total Allocated Entitlements in PGA	323,873	311,502	297,082	0	0	0

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

Direct Assigned Entitlements in PGA	M-10-Peoples Mn GS	M-11-Peoples Mn GS	M-12-Peoples Mn GS	M-13-Peoples Mn GS	M-14-Peoples Mn GS	Proposed Change
TF12B				**49,153**	**49,153**	**0**
TF12V				**26,926**	**26,926**	**0**
TF5				**31,515**	**31,515**	**0**
TFX12				**32,297**	**32,297**	**0**
TFX(5)				**93,084**	**93,084**	**0**
TFX(5) (12-V)						**0**
TFX (October Only)				**2,000**	**2,000**	**0**
TFX (April Only)				**2,000**	**2,000**	**0**
Windom	2,500	2,500	2,500	**2,500**	**2,500**	**0**
Northwestern Energy	0	910	910	**910**	**910**	**0**
NNG Zone Delivery Call Option				**20,000**	**20,000**	**0**
LS Power	0	0	0	**0**	**0**	**0**
Bison *				**50,000**	**50,000**	**0**
NBPL *				**50,000**	**50,000**	**0**
TFX (October Only)	0	0	0	**0**	**0**	**0**
TFX (April Only)	0	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	2,500	3,410	3,410	**256,385**	**256,385**	**0**
Total Capacity before Peak Shaving	233,627	221,436	208,918	**256,385**	**256,385**	**0**
LP Peak Shaving	0	0				**0**
Total Design Day Capacity	233,627	221,436	208,918	**256,385**	**256,385**	**0**
Total Transp. (with TFX Offpeak less LSP)	207,676	221,436	208,918	**256,385**	**256,385**	**0**
Total Annual Transportation	98,467	100,133	99,107	**111,786**	**111,786**	**0**
Total Seasonal Transportation	135,160	110,068	108,901	**144,599**	**144,599**	**0**
Total Percent Seasonal	57.9%	49.7%	52.1%	**56.4%**	**56.4%**	**0.0%**
LS Power as % of Total DD Capacity	11.1%	0.0%	0.0%	**0.0%**	**0.0%**	**0.0%**
Reserve Margin	20.06%	4.86%	4.05%	**4.27%**	**4.27%**	**0.0%**

Direct Assigned Demand Not in PGA

MERC Attachment 10
NNG Demand Entitlements

TF-12-B Contract Demand	0	0	0	**0**	**0**	0
Total Design Day Capacity w/ contract demand	233,627	221,436	208,007	**256,385**	**256,385**	0
Factors	35.92%	33.31%	38.29%	**28.43%**	**28.07%**	0.36%
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	1,784	1,798	1,779	**2,000**	**2,000**	0
TFX Apr	1,784	1,798	1,779	**2,000**	**2,000**	0
TFX Apr-Oct	0	0	0	**0**	**0**	0
TFX May-Sept	0	0	0	**0**	**0**	0
FDD Storage reservation	78,409	84,483	86,671	**97,463**	**94,863**	2,600
FDD Storage capacity	4,520,719	4,870,885	4,997,056	**5,619,321**	**5,469,321**	150,000
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	20,226	20,385	20,168	**22,680**	**22,680**	0
SBA	0	0	0	**0**	**0**	0

MINNESOTA ENERGY RESOURCES - NNG

Rate Impacts
NNG

1) General Service Residential: Avg. Annual Use:				93 Dth					
Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$1.7955	$1.6968	$1.7177	$1.7822	$1.7920	-0.19%	4.33%	0.55%	$0.0098
Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$8.5880	$7.5547	$7.7406	$8.0562	$8.0779	-5.94%	4.36%	0.27%	$0.0217
Avg. Annual Bill*	$798.68	$702.59	$719.88	$749.23	$751.24	-5.94%	4.36%	0.27%	$2.02
Effect of proposed commodity change on average annual bills:									$1.11
Effect of proposed demand change on average annual bills:									$0.91

2) Small Volume Interruptible: Avg. Annual Use:				6,699 Dth					
Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate									$0.0000
Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$5.7649	$4.9472	$5.1122	$5.2464	$5.2583	-8.79%	2.86%	0.23%	$0.0119
Avg. Annual Bill*	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$35,225.35	-8.79%	2.86%	0.23%	$79.72
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use:				42,000 Dth					
Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate									$0.0000
Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	-10.20%	1.25%	0.27%	$0.0119
Avg. Annual Bill*	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$187,299.00	-10.20%	1.25%	0.27%	$499.80
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use:				6,699 Dth					
Avg. Annual CD Volumes:				25 Dth					
Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$18.8796	$19.4140	$18.8796	$18.8911	$19.0459	0.88%	0.88%	0.82%	$0.1548
Comm. Margin	$1.2014	$1.2781	$1.0647	$1.0647	$1.2014	0.00%	12.84%	12.84%	$0.1367
SV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$5.7649	$5.1606	$5.1122	$5.1097	$5.2583	-8.79%	2.86%	2.91%	$0.1486
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$21.6412	0.77%	2.18%	0.72%	$0.1548
Avg. Annual Bill*	$39,155.94	$35,113.71	$34,776.12	$34,767.04	$35,766.38	-8.66%	2.85%	2.87%	$999.34
Effect of proposed commodity change on average annual bills:									$79.72
Effect of proposed demand change on average annual bills:									$3.87

5) Large Volume Firm: Avg. Annual Use:				42,000 Dth					
Avg. Annual CD Units:				75 Dth					
Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.0569	-11.10%	0.23%	0.29%	$0.0119
Demand Rate	$18.8796	$19.3628	$19.3628	$19.4140	$19.0459	0.88%	-1.64%	-1.90%	($0.3681)
Comm. Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
LV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$4.9661	$4.2393	$4.4043	$4.4476	$4.4595	-10.20%	1.25%	0.27%	$0.0119
Total Demand Cost	$21.4749	$21.6628	$21.6628	$22.0093	$21.6412	0.77%	-0.10%	-1.67%	($0.3681)
Avg. Annual Bill*	$210,186.82	$179,675.31	$186,605.31	$188,449.90	$188,922.09	-10.12%	1.24%	0.25%	$472.19
Effect of proposed commodity change on average annual bills:									$499.80
Effect of proposed demand change on average annual bills:									-$27.61

* Average Annual Bill amount does not include customer charges.

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	$0.0119	0.29%	1.19%	$0.0098	0.55%	0.0217		0.27%
Sm Vol Inter. Service	$0.0119	0.29%	1.19%	$0.0000	0.00%	0.0119		0.23%
Lrg Vol Inter. Service	$0.0119	0.29%	1.19%	$0.0000	0.00%	0.0119		0.27%
Sm Vol Joint Service	$0.0119	0.29%	1.19%	$0.1548	0.82%	0.1486	***	2.91%
Lrg Vol Joint Service	$0.0119	0.29%	1.19%	($0.3681)	-1.90%	0.0119	***	0.27%

*** 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: 93 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$1.7955	$1.6968	$1.7177	$1.7822	$1.6006	-10.85%	-6.81%	-10.19%	($0.1816)
Margin	$2.2290	$1.9754	$1.9754	$2.2290	$2.2290	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$8.5880	$7.5547	$7.7406	$8.0562	$8.0621	-6.12%	4.15%	0.07%	$0.0059
Avg. Annual Bill*	$798.68	$702.59	$719.88	$749.23	$749.78	-6.12%	4.15%	0.07%	$0.55
Effect of proposed commodity change on average annual bills:									$17.43
Effect of proposed demand change on average annual bills:									($16.89)

2) Small Volume Interruptible: Avg. Annual Use: 6,699 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate									
Margin	$1.2014	$1.0647	$1.0647	$1.2014	$1.2014	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$5.7649	$4.9472	$5.1122	$5.2464	$5.4339	-5.74%	6.29%	3.57%	$0.1875
Avg. Annual Bill*	$38,619.07	$33,141.29	$34,246.63	$35,145.63	$36,401.42	-5.74%	6.29%	3.57%	$1,255.78
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									$0.00

3) Large Volume Interruptible: Avg. Annual Use: 42,000 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate									
Margin	$0.4026	$0.3568	$0.3568	$0.4026	$0.4026	0.00%	12.84%	0.00%	$0.0000
Total Recovery	$4.9661	$4.2393	$4.4043	$4.4476	$4.6351	-6.67%	5.24%	4.21%	$0.1875
Avg. Annual Bill*	$208,576.20	$178,050.60	$184,980.60	$186,799.20	$194,672.44	-6.67%	5.24%	4.21%	$7,873.24
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									$0.00

4) Small Volume Firm: Avg. Annual Use: 6,699 Dth
Avg. Annual CD Volumes: 25 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$18.8796	$19.4140	$18.8796	$18.8911	$17.5531	-7.03%	-7.03%	-7.08%	($1.3380)
Comm. Margin	$1.2014	$1.0647	$1.0647	$1.0647	$1.0647	-11.38%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$5.7649	$4.9472	$5.1122	$5.1097	$5.2972	-8.11%	3.62%	3.67%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$21.4864	$20.1484	-6.18%	-4.87%	-6.23%	($1.3380)
Avg. Annual Bill*	$39,155.94	$33,684.14	$34,776.12	$34,767.04	$35,989.37	-8.09%	3.49%	3.52%	$1,222.33
Effect of proposed commodity change on average annual bills:									$1,255.78
Effect of proposed demand change on average annual bills:									($33.45)

5) Large Volume Firm: Avg. Annual Use: 42,000 Dth
Avg. Annual CD Units: 75 Dth

Recovery	Base Cost of Gas Change G011/MR13-732	Demand Change Jul '13 12-1193	Last Demand Change Nov '13 13-670	Most Recent PGA Aug. 2014	Nov14 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	$4.5635	$3.8825	$4.0475	$4.0450	$4.2325	-7.25%	4.57%	4.63%	$0.1875
Demand Rate	$18.8796	$19.4140	$18.8796	$19.4140	$17.5531	-7.03%	-7.03%	-9.59%	($1.8609)
Comm. Margin	$0.4026	$0.3568	$0.3568	$0.3568	$0.3568	-11.38%	0.00%	0.00%	$0.0000
LV Dem. Margin	$2.5953	$2.3000	$2.3000	$2.5953	$2.5953	0.00%	12.84%	0.00%	$0.0000
Total Commodity Cost	$4.9661	$4.2393	$4.4043	$4.4018	$4.5893	-7.59%	4.20%	4.26%	$0.1875
Total Demand Cost	$21.4749	$21.7140	$21.1796	$22.0093	$20.1484	-6.18%	-4.87%	-8.45%	($1.8609)
Avg. Annual Bill*	$210,186.82	$179,679.15	$186,569.07	$186,526.30	$194,259.97	-7.58%	4.12%	4.15%	$7,733.67
Effect of proposed commodity change on average annual bills:									$7,873.24
Effect of proposed demand change on average annual bills:									($139.57)

* Average Annual Bill amount does not include customer charges.

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	$0.1875	4.63%	18.75%	($0.1816)	-10.19%	0.0059		0.07%
Sm Vol Inter. Service	$0.1875	4.63%	18.75%	$0.0000	0.00%	0.1875		3.57%
Lrg Vol Inter. Service	$0.1875	4.63%	18.75%	$0.0000	0.00%	0.1875		4.21%
Sm Vol Joint Service	$0.1875	4.63%	18.75%	($1.3380)	-7.08%	0.1875	***	3.67%
Lrg Vol Joint Service	$0.1875	4.63%	18.75%	($1.8609)	-9.59%	0.1875	***	4.26%

*** 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, 2014 Change in Entitlement Levels and Related Demand Costs

NNG

	Contract	Aug-14 PGA	Nov-14 Entitlement	Entitlement Change	Months	Nov-14 Rate/MCF	Aug-14 Total Cost	Entitlement Total Cost	Entitlement Change
TF12B (Max Rate) Winter	112495	0	43,953	43,953	5	$ 10.2300	$0	$2,248,196	$2,248,196
TF12B (Max Rate) Summer	112495	0	43,190	43,190	7	$ 5.6830	$0	$1,718,141	$1,718,141
TF12B	112495	43,953	0	(43,953)	12	$ 7.5171	$3,964,789	$0	($3,964,789)
TF12V (Max Rate)	112495	26,926	26,926	0	12	$ 9.0926	$2,937,928	$2,937,928	$0
TF5 (Max Rate)	112495	31,515	31,515	0	5	$ 15.1530	$2,387,734	$2,387,734	($0)
TF12B (Discount-Winter)	112495	5,200	5,200	0	12	$ 7.4951	$467,694	$467,694	$0
TFX5 (Discount)	112561	6,000	0	(6,000)	5	$ 4.5600	$136,800	$0	($136,800)
TFX12 (Max Rate)	112486	10,822	10,822	0	12	$ 9.6288	$1,250,434	$1,250,434	$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
TFX5 (Max Rate)	112486	60,271	66,271	6,000	5	$ 15.1530	$4,566,432	$5,021,022	$454,590
TFX5 (Discount)	112486	1,800	1,800	0	5	$ 7.6000	$68,400	$68,400	$0
TFX12 (Discount)	111866	1,283	1,283	0	12	$ 4.8640	$74,886	$74,886	$0
TFX12 (Discount)	111866	8,271	8,271	0	12	$ 5.4720	$543,107	$543,107	($0)
TFX12 (Discount)	111866	11,921	11,921	0	12	$ 7.6025	$1,087,553	$1,087,553	($0)
TFX5 (Discount)	111866	379	379	0	5	$ 4.8640	$9,217	$9,217	$0
TFX5 (Discount)	111866	2,445	2,445	0	5	$ 5.4720	$66,895	$66,895	$0
TFX5 (Discount)	111866	22,189	22,189	0	5	$ 15.1392	$1,679,619	$1,679,619	($0)
Bison	FT0003	50,000	50,000	0	12	$ 17.4896	$10,493,760	$10,493,750	($10)
NBPL	T8673F	50,000	50,000	0	12	$ 6.9958	$4,197,480	$4,197,500	$20
Windom		2,500	2,500	0	12	$ -	$0	$0	$0
Ortonville		910	910	0	12	$ 8.0000	$87,360	$87,360	$0
NNG Zone GDD Call Option		20,000	20,000	0	3	$ 0.9000	$54,000	$54,000	$0
Total Demand Cost							$34,096,820	$34,416,169	$319,349

Costs Assigned In Commodity:		Aug-14 PGA	Nov-14 Entitlement	Entitlement Change	Months	Nov-14 Rate/MCF	Aug-14 Total Cost	Entitlement Total Cost	Entitlement Change
Upstream				0				$0	$0
Surcharges:				0				$0	$0
				0				$0	$0
Storage (FDD)									
Storage Reservation	118657	75,437	75,437	0	12	$ 1.7140	$1,551,588	$1,551,588	$0
Storage Cycle Volume	118657	869,864	869,864	0	5	$ 0.3567	$1,551,402	$1,551,402	$0
Storage Reservation	118657	5,550	5,550	0	12	$ 3.3157	220826	$220,826	($0)
Storage Cycle Volume	118657	64,000	64,000	0	5	$ 0.6901	$220,832	$220,832	$0
Storage Reservation	125915	13,009	2,602	(10,407)	12	$ 1.7140	$267,569	$53,518	($214,051)
Storage Cycle Volume	125915	150,000	30,000	(120,000)	5	$ 0.3567	$267,525	$53,505	($214,020)
Storage Reservation	125916	3,468	11,274	7,806	12	$ 1.7140	$71,330	$231,884	$160,554
Storage Cycle Volume	125916	40,000	130,000	90,000	5	$ 0.3567	$71,340	$231,855	$160,515
SMS-Bal Service		272,160	272,160	0	1	$ 2.1800	$593,309	$593,309	($0)
Producer Demand Payments/Option Premium							$1,269,879	$1,549,901	$280,022
Total Commodity Costs							$6,085,601	$6,258,620	$173,019

MINNESOTA ENERGY RESOURCES - NNG

Attachment 13

Daily Total Throughput Data - July 1, 2013 through June 30, 2014

NNG

Base	41,361
Variable	2,341

Date	12.04% Cloquet Adjusted HDD	28.20% Minneapolis Adjusted HDD	47.24% Rochester Adjusted HDD	12.52% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/13	4	0	0	0	0	50,494	42,522
7/2/13	2	0	0	0	0	49,986	41,936
7/3/13	0	0	0	0	0	45,362	41,361
7/4/13	0	0	0	0	0	37,892	41,361
7/5/13	0	0	0	0	0	42,393	41,361
7/6/13	5	0	0	0	1	39,459	42,883
7/7/13	1	0	0	0	0	44,996	41,651
7/8/13	1	0	0	0	0	52,003	41,657
7/9/13	0	0	0	0	0	49,286	41,361
7/10/13	0	0	0	0	0	52,536	41,361
7/11/13	0	0	0	0	0	51,561	41,361
7/12/13	0	0	0	0	0	45,400	41,361
7/13/13	0	0	0	0	0	38,769	41,361
7/14/13	0	0	0	0	0	43,076	41,361
7/15/13	0	0	0	0	0	50,907	41,361
7/16/13	0	0	0	0	0	60,710	41,361
7/17/13	0	0	0	0	0	63,035	41,361
7/18/13	0	0	0	0	0	58,928	41,361
7/19/13	4	0	0	0	1	51,847	42,556
7/20/13	6	0	0	0	1	37,692	43,187
7/21/13	0	0	0	0	0	42,140	41,361
7/22/13	4	0	0	0	1	50,762	42,545
7/23/13	5	0	0	1	1	51,676	43,134
7/24/13	0	0	0	0	0	52,292	41,361
7/25/13	11	1	5	0	4	50,465	50,165
7/26/13	17	7	12	9	11	47,195	66,763
7/27/13	9	2	8	10	6	42,411	56,470
7/28/13	6	0	3	5	3	44,081	48,139
7/29/13	0	0	0	0	0	52,512	41,361
7/30/13	0	0	0	1	0	57,396	41,666
7/31/13	0	0	0	0	0	54,470	41,361
8/1/13	3	0	0	0	0	53,062	42,266
8/2/13	6	0	0	5	1	45,603	44,677
8/3/13	6	0	2	4	2	42,470	46,690
8/4/13	1	0	0	0	0	40,920	41,648
8/5/13	1	0	0	0	0	50,499	41,654
8/6/13	5	0	0	0	1	52,285	42,869
8/7/13	3	0	0	0	0	52,753	42,232
8/8/13	8	0	0	1	1	56,898	43,805
8/9/13	2	0	1	1	1	48,154	43,408
8/10/13	3	0	0	0	0	41,956	42,232
8/11/13	5	0	0	0	1	43,303	42,855
8/12/13	8	0	3	0	3	50,787	47,222
8/13/13	7	0	3	2	3	51,494	47,484
8/14/13	3	0	2	3	2	55,399	45,517
8/15/13	0	0	0	7	1	50,708	43,495
8/16/13	0	0	0	2	0	43,348	41,994
8/17/13	0	0	0	0	0	37,087	41,361
8/18/13	0	0	0	0	0	45,236	41,361
8/19/13	0	0	0	0	0	51,818	41,361
8/20/13	0	0	0	0	0	51,712	41,361
8/21/13	0	0	0	0	0	50,062	41,361
8/22/13	1	0	0	0	0	51,602	41,651
8/23/13	0	0	0	0	0	47,374	41,361
8/24/13	0	0	0	0	0	39,972	41,361
8/25/13	0	0	0	0	0	44,225	41,361
8/26/13	0	0	0	0	0	51,305	41,361
8/27/13	0	0	0	0	0	49,798	41,361
8/28/13	0	0	0	0	0	51,870	41,361
8/29/13	0	0	0	0	0	54,405	41,361
8/30/13	0	0	0	0	0	46,048	41,361
8/31/13	2	0	0	0	0	39,408	41,987
9/1/13	11	4	9	4	7	39,784	57,963
9/2/13	7	0	5	4	4	47,644	50,433
9/3/13	6	0	0	0	1	54,040	43,119
9/4/13	7	0	0	0	1	55,983	43,393

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9/5/13	0	0	0	0	0	54,327	41,361
9/6/13	0	0	0	0	0	48,291	41,361
9/7/13	5	0	0	0	1	45,163	42,855
9/8/13	3	0	0	0	0	45,642	42,223
9/9/13	0	0	0	0	0	58,803	41,361
9/10/13	1	0	0	0	0	62,275	41,665
9/11/13	12	0	3	0	3	59,864	48,391
9/12/13	15	5	8	7	8	55,170	60,623
9/13/13	10	3	7	5	6	48,760	55,107
9/14/13	20	8	10	3	10	43,909	63,917
9/15/13	18	10	12	13	12	51,015	69,408
9/16/13	13	7	13	9	11	60,142	66,668
9/17/13	5	0	0	3	1	56,716	43,834
9/18/13	1	0	0	0	0	57,047	41,654
9/19/13	11	8	10	4	9	57,654	62,139
9/20/13	15	10	12	20	12	58,282	70,608
9/21/13	16	4	9	6	8	50,044	60,508
9/22/13	9	1	6	0	4	49,170	50,767
9/23/13	6	1	7	0	4	56,012	51,058
9/24/13	8	1	7	5	5	56,736	53,204
9/25/13	7	0	0	0	1	56,527	43,472
9/26/13	1	0	0	0	0	56,188	41,663
9/27/13	8	4	8	0	6	52,067	55,294
9/28/13	9	2	8	11	7	50,978	57,194
9/29/13	0	0	1	0	1	51,303	42,677
9/30/13	6	0	0	0	1	59,219	42,911
10/1/13	8	3	6	4	5	69,594	53,192
10/2/13	13	8	3	0	5	65,369	53,702
10/3/13	16	9	6	9	8	66,160	60,699
10/4/13	21	12	13	17	14	58,469	74,338
10/5/13	18	18	19	21	19	62,374	85,490
10/6/13	17	10	11	23	13	73,237	71,418
10/7/13	8	1	5	8	4	76,747	51,624
10/8/13	2	0	3	1	2	68,211	46,050
10/9/13	5	0	4	0	3	65,127	47,750
10/10/13	3	0	2	0	2	54,427	44,879
10/11/13	11	15	16	8	14	54,022	74,621
10/12/13	21	15	19	19	18	65,048	83,861
10/13/13	23	18	19	15	19	74,019	85,251
10/14/13	23	17	16	18	17	93,518	81,770
10/15/13	21	18	27	24	23	93,772	96,000
10/16/13	26	15	23	22	21	103,116	90,200
10/17/13	24	22	26	22	24	108,623	97,545
10/18/13	29	24	29	26	28	111,310	106,025
10/19/13	34	27	28	26	28	117,112	107,556
10/20/13	38	34	38	25	35	123,082	123,624
10/21/13	36	32	36	28	34	163,407	121,264
10/22/13	36	32	35	33	34	157,487	121,069
10/23/13	33	29	33	35	32	168,604	116,858
10/24/13	29	23	29	31	28	156,612	106,119
10/25/13	28	25	27	24	26	123,727	102,086
10/26/13	28	21	24	32	25	124,993	99,681
10/27/13	34	28	27	23	28	117,072	106,435
10/28/13	37	31	25	32	29	151,427	109,732
10/29/13	30	24	20	26	23	139,226	94,603
10/30/13	24	20	17	25	20	113,393	88,065
10/31/13	26	25	27	29	27	127,997	103,751
11/1/13	31	25	26	27	26	130,046	102,882
11/2/13	30	24	29	23	27	138,715	104,554
11/3/13	22	18	21	19	20	114,180	87,763
11/4/13	30	26	28	29	28	141,938	106,655
11/5/13	34	29	31	40	32	152,358	116,692
11/6/13	39	33	35	39	35	150,822	124,000
11/7/13	41	36	36	38	37	163,725	127,874
11/8/13	36	30	32	27	31	138,186	115,079
11/9/13	36	30	32	36	32	133,889	117,298
11/10/13	41	36	34	40	36	135,223	125,857
11/11/13	56	50	55	61	55	195,890	169,095
11/12/13	47	45	51	52	49	184,801	155,994
11/13/13	32	27	34	27	31	146,246	113,990
11/14/13	28	24	31	24	28	142,533	106,655
11/15/13	25	20	22	23	22	120,393	92,879
11/16/13	23	22	21	21	21	100,929	91,012
11/17/13	36	33	35	31	34	137,135	121,127
11/18/13	46	38	41	33	40	167,552	134,604
11/19/13	37	32	35	24	33	145,391	118,438
11/20/13	30	27	31	34	30	143,060	111,936

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11/21/13	50	46	46	61	48	183,219	154,285
11/22/13	54	50	55	56	54	199,322	166,930
11/23/13	63	55	62	60	60	215,695	181,042
11/24/13	49	48	57	50	53	179,535	164,281
11/25/13	47	41	41	42	42	167,090	139,004
11/26/13	60	54	58	59	57	215,488	175,111
11/27/13	53	49	51	52	51	190,639	160,414
11/28/13	59	46	49	51	49	180,957	157,191
11/29/13	48	43	44	44	44	169,625	144,463
11/30/13	36	35	33	35	34	141,935	121,306
12/1/13	43	36	37	36	37	154,330	128,481
12/2/13	39	33	34	30	34	159,074	120,390
12/3/13	41	35	34	40	36	166,309	125,381
12/4/13	52	52	51	60	53	201,073	164,683
12/5/13	73	70	70	79	71	259,103	208,271
12/6/13	82	75	72	81	75	275,153	217,215
12/7/13	81	71	67	71	70	261,158	205,833
12/8/13	73	65	64	71	66	243,830	196,598
12/9/13	77	68	71	71	71	279,992	206,997
12/10/13	80	68	70	71	71	272,689	207,068
12/11/13	80	68	72	73	72	281,572	210,125
12/12/13	67	54	52	52	54	233,152	168,168
12/13/13	69	57	54	60	58	235,989	176,164
12/14/13	75	63	66	64	66	242,974	195,278
12/15/13	79	66	66	65	67	250,607	199,375
12/16/13	58	51	53	52	53	228,493	164,719
12/17/13	59	51	55	48	53	222,310	165,739
12/18/13	58	41	41	49	44	193,728	144,371
12/19/13	61	54	52	64	55	225,365	169,946
12/20/13	57	49	49	59	51	215,440	161,236
12/21/13	54	50	51	61	52	205,398	163,513
12/22/13	70	63	68	75	68	241,629	200,467
12/23/13	79	77	81	80	79	285,291	227,444
12/24/13	71	67	70	62	68	235,724	200,574
12/25/13	58	49	52	46	51	200,830	160,399
12/26/13	57	46	46	47	47	193,806	151,954
12/27/13	39	37	40	38	38	161,373	131,474
12/28/13	63	48	50	60	52	183,175	163,968
12/29/13	86	77	78	76	78	275,395	225,128
12/30/13	79	72	75	64	73	281,745	213,032
12/31/13	86	74	75	77	76	278,833	219,476
1/1/14	83	74	75	82	77	277,248	220,836
1/2/14	79	72	78	75	76	288,267	220,135
1/3/14	62	52	58	53	56	232,162	173,002
1/4/14	79	68	70	72	71	256,427	207,358
1/5/14	91	90	95	92	93	300,315	258,242
1/6/14	95	89	94	85	92	310,124	255,593
1/7/14	82	71	73	63	73	295,830	211,469
1/8/14	78	70	77	66	74	297,517	213,785
1/9/14	61	57	61	57	59	238,587	179,986
1/10/14	44	41	41	46	42	181,551	139,779
1/11/14	45	41	45	41	44	174,737	143,403
1/12/14	39	33	35	39	36	152,994	124,551
1/13/14	49	43	42	41	43	182,482	141,841
1/14/14	67	61	67	61	64	234,565	191,996
1/15/14	56	50	58	54	55	219,620	169,879
1/16/14	67	60	60	63	61	251,340	183,892
1/17/14	62	62	66	54	63	235,470	188,286
1/18/14	51	49	56	51	53	194,608	165,362
1/19/14	55	37	41	36	41	168,616	137,552
1/20/14	82	68	68	66	69	267,929	203,742
1/21/14	79	72	75	71	74	275,195	215,192
1/22/14	88	82	84	78	84	305,545	236,900
1/23/14	78	69	78	71	75	290,343	216,053
1/24/14	61	54	57	50	56	213,218	171,564
1/25/14	70	67	64	50	64	230,378	190,859
1/26/14	84	77	81	70	79	246,423	225,283
1/27/14	89	83	89	81	86	277,268	242,860
1/28/14	83	77	82	76	80	271,765	228,407
1/29/14	65	51	60	50	57	217,374	174,560
1/30/14	76	67	64	65	66	258,878	196,320
1/31/14	73	67	71	62	69	256,280	202,297
2/1/14	71	62	67	68	66	243,535	195,691
2/2/14	67	64	70	62	67	248,006	197,845
2/3/14	64	59	60	62	60	249,302	182,646
2/4/14	72	68	68	77	70	266,648	204,470
2/5/14	76	75	80	78	78	290,770	223,487

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2/6/14	75	74	79	78	77	284,856	221,769
2/7/14	76	66	70	67	69	261,562	203,161
2/8/14	67	62	65	69	65	244,121	193,637
2/9/14	77	75	79	78	78	276,780	222,919
2/10/14	78	70	79	75	76	296,445	218,740
2/11/14	69	66	73	67	70	260,795	204,977
2/12/14	55	48	54	53	52	225,638	164,263
2/13/14	64	55	58	54	57	247,712	175,842
2/14/14	67	61	69	65	66	244,443	195,713
2/15/14	63	57	60	51	58	223,836	178,132
2/16/14	63	55	60	56	58	208,034	178,087
2/17/14	46	44	47	39	45	199,032	147,187
2/18/14	37	34	40	38	38	165,814	130,059
2/19/14	33	36	39	33	37	153,192	127,584
2/20/14	52	52	53	53	52	196,704	164,167
2/21/14	68	63	65	54	64	228,687	190,352
2/22/14	66	64	68	60	65	222,741	194,583
2/23/14	66	64	71	59	67	232,251	197,636
2/24/14	73	66	72	65	70	259,187	204,117
2/25/14	78	74	81	75	78	289,751	224,283
2/26/14	82	74	79	73	77	291,062	221,614
2/27/14	77	75	80	73	77	288,662	221,748
2/28/14	73	65	66	68	67	262,972	197,832
3/1/14	86	81	82	83	82	290,099	234,099
3/2/14	81	73	81	76	78	287,677	224,741
3/3/14	69	66	69	66	68	268,127	199,482
3/4/14	61	53	55	59	55	225,355	171,267
3/5/14	59	50	58	57	56	212,031	171,740
3/6/14	48	46	50	44	48	191,559	153,134
3/7/14	50	46	41	56	45	188,843	147,723
3/8/14	49	45	52	50	49	169,607	157,060
3/9/14	36	32	39	30	35	137,893	124,242
3/10/14	24	21	28	23	25	117,272	99,636
3/11/14	46	38	41	39	41	167,613	136,863
3/12/14	50	39	48	38	45	183,505	145,795
3/13/14	32	24	31	21	28	130,788	107,338
3/14/14	45	37	39	33	38	158,184	131,243
3/15/14	59	49	50	49	51	177,122	160,289
3/16/14	46	44	48	47	47	179,674	150,410
3/17/14	42	36	38	31	37	165,660	127,328
3/18/14	41	38	35	38	37	158,642	128,534
3/19/14	46	36	39	34	38	166,001	130,570
3/20/14	33	29	34	28	32	135,837	116,045
3/21/14	54	44	42	44	45	172,277	145,676
3/22/14	64	55	57	53	57	198,578	173,753
3/23/14	60	44	45	46	47	195,002	150,606
3/24/14	59	52	52	51	53	200,270	164,334
3/25/14	59	47	51	50	51	211,232	159,631
3/26/14	40	32	35	30	34	158,730	121,377
3/27/14	45	36	37	42	38	162,980	130,709
3/28/14	46	36	37	45	39	150,573	132,234
3/29/14	32	26	28	32	28	118,070	107,677
3/30/14	24	13	18	11	16	100,127	79,600
3/31/14	45	30	30	29	32	137,588	116,358
4/1/14	46	37	36	41	38	175,169	130,696
4/2/14	36	32	30	38	32	138,246	116,381
4/3/14	39	37	40	40	39	163,682	133,194
4/4/14	36	30	32	38	33	144,608	118,436
4/5/14	23	15	19	31	20	106,202	87,370
4/6/14	26	17	19	17	19	90,062	85,723
4/7/14	30	23	25	21	24	103,963	98,679
4/8/14	24	13	20	26	19	112,266	86,734
4/9/14	25	14	17	9	16	83,843	79,195
4/10/14	20	13	15	16	15	92,638	77,000
4/11/14	31	17	21	8	19	77,622	86,044
4/12/14	35	31	32	12	30	88,614	110,522
4/13/14	47	40	42	45	42	139,985	139,986
4/14/14	46	40	40	46	42	172,196	138,727
4/15/14	44	37	29	38	34	150,964	121,499
4/16/14	36	33	32	36	33	150,497	119,584
4/17/14	39	28	26	33	29	144,168	109,601
4/18/14	28	11	14	18	16	105,337	77,890
4/19/14	19	5	5	6	7	73,894	57,672
4/20/14	19	10	12	0	11	59,301	66,292
4/21/14	24	19	21	19	21	88,098	89,790
4/22/14	27	24	26	11	23	97,687	96,110
4/23/14	33	25	25	22	26	122,600	101,809

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4/24/14	31	16	18	20	19	126,572	86,520
4/25/14	32	22	21	11	21	90,363	91,144
4/26/14	38	29	27	15	28	90,599	105,837
4/27/14	34	26	27	20	27	119,095	104,447
4/28/14	31	32	32	29	32	137,739	115,234
4/29/14	31	28	31	32	30	142,398	112,703
4/30/14	26	25	26	30	26	130,985	103,185
5/1/14	25	16	17	28	19	114,402	85,857
5/2/14	24	16	17	17	18	86,076	82,444
5/3/14	24	19	18	18	19	79,875	86,669
5/4/14	25	9	11	22	13	77,868	72,782
5/5/14	28	10	12	11	13	79,417	72,288
5/6/14	21	8	8	6	9	76,626	63,534
5/7/14	22	5	0	0	4	70,931	51,292
5/8/14	26	13	18	6	16	72,525	78,125
5/9/14	14	10	13	13	12	82,643	69,994
5/10/14	12	6	4	6	6	54,506	55,384
5/11/14	27	10	4	12	10	53,997	63,775
5/12/14	20	19	22	26	21	80,194	91,612
5/13/14	23	17	19	22	20	88,383	87,126
5/14/14	26	22	23	21	23	85,978	94,394
5/15/14	22	19	22	32	23	102,029	94,472
5/16/14	21	13	16	21	16	87,539	78,820
5/17/14	6	6	8	9	7	57,073	58,293
5/18/14	16	12	11	0	10	51,295	65,079
5/19/14	5	0	0	4	1	72,103	44,116
5/20/14	13	7	7	2	7	62,361	57,575
5/21/14	12	6	8	8	8	67,382	59,540
5/22/14	9	2	2	1	3	58,628	47,935
5/23/14	1	0	1	0	1	46,617	42,879
5/24/14	0	0	0	0	0	37,057	41,361
5/25/14	0	0	0	0	0	38,704	41,361
5/26/14	11	0	0	0	1	47,309	44,404
5/27/14	11	0	0	0	1	65,305	44,348
5/28/14	4	0	0	0	0	55,545	42,522
5/29/14	5	0	0	0	1	55,336	42,840
5/30/14	5	0	0	0	1	53,706	42,826
5/31/14	2	0	0	0	0	43,904	41,942
6/1/14	2	0	0	0	0	46,347	41,975
6/2/14	2	0	1	1	1	58,867	43,504
6/3/14	5	0	0	1	1	34,875	43,157
6/4/14	9	0	0	0	1	58,901	43,999
6/5/14	0	0	0	0	0	56,271	41,361
6/6/14	11	6	1	0	4	52,135	49,848
6/7/14	11	4	3	11	5	44,262	54,171
6/8/14	7	0	0	3	1	45,560	44,351
6/9/14	8	0	0	5	2	58,413	45,259
6/10/14	7	0	0	0	1	59,435	43,413
6/11/14	18	6	7	0	7	59,601	58,238
6/12/14	9	2	3	8	4	61,776	51,345
6/13/14	15	3	0	0	3	49,029	47,979
6/14/14	7	0	0	2	1	43,098	43,907
6/15/14	0	0	0	0	0	46,623	41,361
6/16/14	0	0	0	0	0	59,635	41,361
6/17/14	6	0	0	0	1	56,975	42,981
6/18/14	13	0	0	0	2	56,330	45,047
6/19/14	15	0	0	0	2	56,109	45,622
6/20/14	6	0	0	0	1	50,436	43,119
6/21/14	9	0	0	0	1	39,496	43,973
6/22/14	0	0	0	0	0	46,058	41,361
6/23/14	13	0	0	0	2	55,396	45,047
6/24/14	14	2	0	0	2	56,699	46,694
6/25/14	11	0	0	0	1	59,819	44,376
6/26/14	9	0	0	0	1	56,040	43,773
6/27/14	0	0	0	0	0	50,652	41,361
6/28/14	0	0	0	0	0	41,907	41,361
6/29/14	0	0	0	0	0	47,729	41,361
6/30/14	1	0	3	0	2	55,559	45,450
Totals	11,522	9,475	10,104	9,840	10,064	########	38,657,124

* 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

MERC

MINNESOTA ENERGY RESOURCES - NNG

Customer Counts by PGAC Class - July 1, 2013 through June 30, 2014

Attachment 14

Rate Class	Tariff Rate Designation	Jul-13 Average Customers	Aug-13 Average Customers	Sep-13 Average Customers	Oct-13 Average Customers	Nov-13 Average Customers	Dec-13 Average Customers	Jan-14 Average Customers	Feb-14 Average Customers	Mar-14 Average Customers	Apr-14 Average Customers	May-14 Average Customers	Jun-14 Average Customers	Annual Average Customers
GS- Residential (w/ Heat)	2H801 / 2HS01 2HS02	160,366	161,713	161,822	162,267	162,257	163,703	167,028	163,698	164,199	158,550	162,775	163,807	162,682
GS-Residential (w/o Heat)	2R801 / 2RS01 2RS02	921	939	933	938	932	942	965	942	945	917	929	935	937
GS-C&I <1,500 therms/yr (Small)	2C805 / 2CS05 2I805 / 2IS05 2C806 / 2CS06 2CS07 / 2IS07 2CS08	8,197	8,230	8,222	8,253	8,255	8,332	8,545	8,405	8,398	8,139	8,291	8,359	8,302
GS-C&I <1,500 therms/yr (Small) Emmons, IA	2CE05	2	2	2	2	2	2	2	2	2	2	2	2	2
GS-C&I >1,500 therms/yr (Large)	2C810 / 2CS10 2I810 / 2IS10 2CS11 / 2IS11 2C812/ 2CS12 2IS12	7,813	7,824	7,810	7,835	7,843	7,862	8,079	7,918	7,876	7,680	7,848	7,893	7,857
GS-C&I >1,500 therms/yr (Large) Emmons, IA	2CE10	1	1	1	1	1	1	1	1	1	1	1	1	1
Small Volume Interruptible (SVI)	2D820 / 2DS20 2J820 / 2JS20 2DS22	308	311	312	317	316	308	315	306	305	302	304	301	309
Small Volume Interrupt	2C830 / 2CS30 2C830	0	0	0	0	0	0	0	3	3	3	3	3	1
Large Volume Interrupt	2D840 / 2DS40 2J840 / 2JS40 2D842	57	56	59	62	59	57	61	58	58	63	67	60	60
Large Volume Interrupt	2IS50 / 2JS50	0	0	0	0	0	0	0	0	0	0	0	0	0
Super Large Volume In	2DS60 / 2JS60	0	0	0	0	0	0	0	0	0	0	0	0	0
Super Large Volume In	2IS70 / 2JS70	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		177,665	179,076	179,161	179,675	179,665	181,207	184,996	181,333	181,787	175,657	180,220	181,361	180,150

MINNESOTA ENERGY RESOURCES - NNG

Projected Fixed Cost - November 2014 through March 2015

Futures Contracts WACOG

NNG-PNG
Futures

Nov-14 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/25/14	81,552	$ 4.5750	$ 373,099	$ 3.9955	$ 325,840	$ 47,259
07/25/14	88,966	$ 3.8470	$ 342,250	$ 3.9955	$ 355,462	$ (13,211)
08/xx/14	88,966	$ 3.8580	$ 343,229	$ 3.9955	$ 355,462	$ (12,233)
09/xx14	88,966	$ 3.8580	$ 343,229	$ 3.9955	$ 355,462	$ (12,233)
10/xx14	81,552	$ 3.8580	$ 314,627	$ 3.9955	$ 325,840	$ (11,213)
Total	430,000		$ 1,716,434		$ 1,718,065	$ (1,631)
WACOG			$ 3.9917		3.9955	$ (0.0063)

Dec-14 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/16/14	3,529	$ 4.7950	$ 16,924	$ 4.2065	$ 14,846	$ 2,077
06/16/14	7,059	$ 4.8020	$ 33,896	$ 4.2065	$ 29,693	$ 4,204
07/16/14	14,118	$ 4.2330	$ 59,760	$ 4.2065	$ 59,386	$ 374
8/xx/2014	14,118	$ 3.9390	$ 55,609	$ 4.2065	$ 59,386	$ (3,776)
9/xx/2014	10,588	$ 3.9390	$ 41,707	$ 4.2065	$ 44,539	$ (2,832)
10/xx/2014	10,588	$ 3.9390	$ 41,707	$ 4.2065	$ 44,539	$ (2,832)
Total	60,000		$ 249,604		$ 252,390	$ (2,786)
WACOG			$ 4.1601		$ 4.2065	$ (0.0464)

Jan-15 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/11/14	6,939	$ 4.6790	$ 32,467	$ 4.3310	$ 30,052	$ 2,415
06/11/14	48,571	$ 4.6800	$ 227,314	$ 4.3310	$ 210,363	$ 16,951
07/10/14	13,878	$ 4.2950	$ 59,604	$ 4.3310	$ 60,104	$ (500)
07/10/14	62,449	$ 4.2960	$ 268,281	$ 4.3310	$ 270,467	$ (2,186)
8/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
9/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
10/xx/2014	69,388	$ 4.0110	$ 278,314	$ 4.3310	$ 300,518	$ (22,204)
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
Total	340,000		$ 1,422,609		$ 1,472,540	$ (49,931)
WACOG			$ 4.1841		$ 4.3310	$ (0.1469)

Feb-15 (28)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/30/14	35,625	$ 4.5720	$ 162,877	$ 4.2985	$ 153,134	$ 9,743
07/30/14	41,563	$ 4.0100	$ 166,666	$ 4.2985	$ 178,656	$ (11,991)
8/xx/2014	41,563	$ 4.0010	$ 166,292	$ 4.2985	$ 178,656	$ (12,365)
9/xx/2014	35,625	$ 4.0010	$ 142,536	$ 4.2985	$ 153,134	$ (10,598)
10/xx/2014	35,625	$ 4.0010	$ 142,536	$ 4.2985	$ 153,134	$ (10,598)
Total	190,000		$ 780,906		$ 816,715	$ (35,809)
WACOG			$ 4.1100		$ 4.2985	$ (0.1885)

Mar-15 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
06/20/14	38,542	$ 4.5650	$ 175,943	$ 4.1410	$ 159,601	$ 16,342
06/20/14	38,542	$ 4.5750	$ 176,328	$ 4.1410	$ 159,601	$ 16,727
06/20/14	38,542	$ 4.5770	$ 176,405	$ 4.1410	$ 159,601	$ 16,804
06/20/14	38,542	$ 4.5790	$ 176,482	$ 4.1410	$ 159,601	$ 16,881
07/21/14	154,167	$ 3.9850	$ 614,354	$ 4.1410	$ 638,404	$ (24,050)
8/xx/2014	146,458	$ 3.9360	$ 576,460	$ 4.1410	$ 606,484	$ (30,024)
9/xx/2014	146,458	$ 3.9360	$ 576,460	$ 4.1410	$ 606,484	$ (30,024)
10/xx/2014	138,750	$ 3.9360	$ 546,120	$ 4.1410	$ 574,564	$ (28,444)
Total	740,000		$ 3,018,553		$ 3,064,340	$ (45,787)
WACOG			$ 4.0791		$ 4.1410	$ (0.0619)

Total

	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	166,187	$ 4.5811	$ 761,309	$ 4.1127	$ 683,473	$ 77,836
	224,700	$ 4.2121	$ 946,455	$ 4.1557	$ 933,775	$ 12,680
	197,065	$ 4.0864	$ 805,290	$ 4.1266	$ 813,209	$ (7,919)
	239,699	$ 4.1141	$ 986,137	$ 4.1638	$ 998,049	$ (11,912)
	351,319	$ 3.9609	$ 1,391,538	$ 4.1627	$ 1,462,436	$ (70,898)
	226,434	$ 3.9591	$ 896,481	$ 4.2023	$ 951,542	$ (55,060)
	215,846	$ 3.9601	$ 854,774	$ 4.2021	$ 907,002	$ (52,228)
	138,750	$ 3.9360	$ 546,120	$ 4.1410	$ 574,564	$ (28,444)
	1,760,000		$ 7,188,105		$ 7,324,050	$ (135,945)
			$ 4.0842		$ 4.1614	$ (0.0772)

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2014 through March 2015

Month/ Year	K#118657 NNG Storage	Storage K#125915 NNG Storage	Storage K#125916 NNG Storage	Total NNG Storage	Projected Storage NNG WACOG	K#118657 NNG Storage Cost	K#125915 NNG Storage Cost	K#125916 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-14	455,259	14,625	63,375	533,259	$ 4.1998	$ 1,912,006	$ 61,422	$ 266,164	$ 2,239,593	85,304	$ 4.2134	$ 359,423
Dec-14	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	231,769	$ 4.2134	$ 976,543
Jan-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	231,769	$ 4.2134	$ 976,543
Feb-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4,804,528	$ 154,343	$ 668,822	$ 5,627,693	209,339	$ 4.2134	$ 882,035
Mar-15	455,259	14,625	63,375	533,259	$ 4.1998	$ 1,912,006	$ 61,422	$ 266,164	$ 2,239,593	96,374	$ 4.2134	$ 406,065
Total	4,342,470	139,500	604,500	5,086,470	$ 4.1998	$18,237,598	$ 585,875	$ 2,538,792	$21,362,265	854,555	$ 4.2134	$ 3,600,608

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson LDS + Basis	Emerson LDS + Cost
Nov-14	533,259	$ 3.9955	$ 2,130,636	85,304	$ 4.2080	$ 358,959
Dec-14	1,339,984	$ 4.2065	$ 5,636,643	231,769	$ 4.4890	$ 1,040,411
Jan-15	1,339,984	$ 4.3310	$ 5,803,471	231,769	$ 4.8310	$ 1,119,676
Feb-15	1,339,984	$ 4.2985	$ 5,759,921	209,339	$ 4.7110	$ 986,196
Mar-15	533,259	$ 4.1410	$ 2,208,226	96,374	$ 4.5560	$ 439,080
Total	5,086,470	$ 4.2345	$21,538,896	854,555	$ 4.6156	$ 3,944,322

Max NNG Storage (Storage plan withdrawals through Apr 14)	5,086,470	5,469,321	07/30/14 Storage Balance - NNG	2,095,947	38.32%	1,949,231
Max AECO Storage	854,555	947,820	07/30/14 Storage Balance - AECO	567,143	59.84%	511,336
						41.42%

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-14	455,259	14,625	63,375	533,259	$ 4.1998	$ 4.1998	$ 4.1998	$ 2,239,593	$ 3.9955	$ 2,130,636	$ 108,956
Dec-14	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.2065	$ 5,636,643	$ (8,949)
Jan-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.3310	$ 5,803,471	$ (175,777)
Feb-15	1,143,984	36,750	159,250	1,339,984	$ 4.1998	$ 4.1998	$ 4.1998	$ 5,627,693	$ 4.2985	$ 5,759,921	$ (132,228)
Mar-15	455,259	14,625	63,375	533,259	$ 4.1998	$ 4.1998	$ 4.1998	$ 2,239,593	$ 4.1410	$ 2,208,226	$ 31,367
Total	4,342,470	139,500	604,500	5,086,470	$ 4.1998	$ 4.1998	$ 4.1998	$ 21,362,265	$ 4.2345	$ 21,538,896	$ (176,631)
								$ 4.1998	$ (0.2690)	$ (176,631)	

Month/ Year	AECO Storage	AECO Storage Other WACOG	Total AECO Cost	Projected Emerson Index Price	Projected Emerson Index Cost	Additional Storage (Savings)/ Cost
Nov-14	85,304	$ 4.2134	$ 359,423	$ 4.2080	$ 358,959	$ 463
Dec-14	231,769	$ 4.2134	$ 976,543	$ 4.4890	$1,040,411	$ (63,868)
Jan-15	231,769	$ 4.2134	$ 976,543	$ 4.8310	$1,119,676	$ (143,133)
Feb-15	209,339	$ 4.2134	$ 882,035	$ 4.7110	$ 986,196	$ (104,161)
Mar-15	96,374	$ 4.2134	$ 406,065	$ 4.5560	$ 439,080	$ (33,015)
Total	854,555	$ 4.2134	$ 3,600,608	$ 4.6156	$3,944,322	$ (343,714)
			$ 3.2341	$ (0.8488)	$ (343,714)	

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2014 through March 2015

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

			Nov-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	#REF!		17	170,000	$ 5.0000	$ 850,000	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2380	$ 40,460	$ 696,320
2	#REF!		17	170,000	$ 4.2500	$ 722,500	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2220	$ 37,740	$ 693,600
3	#REF!		17	170,000	$ 4.0000	$ 680,000	$ 3.8580	$ 655,860	$ 3.8580	$ 655,860	$ -	$ 0.2300	$ 39,100	$ 694,960
4	#REF!		19	190,000	$ 4.0000	$ 760,000	$ 3.8580	$ 733,020	$ 3.8580	$ 733,020	$ -	$ 0.2300	$ 43,700	$ 776,720
5	#REF!		19	190,000	$ 4.0000	$ 760,000	$ 3.8580	$ 733,020	$ 3.8580	$ 733,020	$ -	$ 0.2300	$ 43,700	$ 776,720
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			89	890,000		$ 3,772,500		$ 3,433,620		$ 3,433,620	$ -		$ 204,700	$ 3,638,320
						$ 4.2388		$ 3.8580		$ 3.8580	$ -		$ 0.0543	$ 4.0880
NNG-Cons	72	80.90%	72	720,000	$ 4.2388	$ 3,051,910	$ 3.8580	$ 2,777,760	$ 3.6613	$ 2,777,760	$ -	$ 0.2300	$ 165,600	$ 2,943,360
Other-Cons	17	19.10%	17	170,000	$ 4.2388	$ 720,590	$ 3.8580	$ 655,860	$ 3.8902	$ 655,860	$ -	$ 0.2300	$ 39,100	$ 694,960
Total	89	100.0%	89	890,000	$ 4.2388	$ 3,772,500	$ 3.8580	$ 3,433,620	$ 3.7060	$ 3,433,620	$ -	$ 0.2300	$ 204,700	$ 3,638,320

			Dec-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	06/27/14		25	250,000	$ 5.0000	$ 1,250,000	$ 3.9390	$ 984,750	$ 3.9390	$ 984,750	$ -	$ 0.2380	$ 59,500	$ 1,044,250
2	07/28/14		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2230	$ 57,980	$ 1,082,120
3	08/14/14		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2305	$ 59,930	$ 1,084,070
4	9/xx/2014		26	260,000	$ 4.0000	$ 1,040,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2305	$ 59,930	$ 1,084,070
5	10/xx/2014		27	270,000	$ 4.0000	$ 1,080,000	$ 3.9390	$ 1,063,530	$ 3.9390	$ 1,063,530	$ -	$ 0.2305	$ 62,235	$ 1,125,765
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			130	1,300,000		$ 5,450,000		$ 5,120,700		$ 5,120,700	$ -		$ 299,575	$ 5,420,275
						$ 4.1923		$ 3.9390		$ 3.9390	$ -		$ 0.0550	$ 4.1694
NNG-Cons	104	80.00%	104	1,040,000	$ 4.1923	$ 4,360,000	$ 3.9390	$ 4,096,560	$ 3.9390	$ 4,096,560	$ -	$ 0.2304	$ 239,660	$ 4,336,220
Other-Cons	26	20.00%	26	260,000	$ 4.1923	$ 1,090,000	$ 3.9390	$ 1,024,140	$ 3.9390	$ 1,024,140	$ -	$ 0.2304	$ 59,915	$ 1,084,055
Total	130	100.0%	130	1,300,000	$ 4.1923	$ 5,450,000	$ 3.9390	$ 5,120,700	$ 3.7060	$ 5,120,700	$ -	$ 0.2304	$ 299,575	$ 5,420,275

			Jan-15											
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	06/23/14		30	300,000	$ 4.7500	$ 1,425,000	$ 4.0110	$ 1,203,300	$ 4.0110	$ 1,203,300	$ -	$ 0.3450	$ 103,500	$ 1,306,800
2	07/24/14		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2370	$ 73,470	$ 1,316,880
3	8/xx/2014		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2910	$ 90,210	$ 1,333,620
4	9/xx/2014		31	310,000	$ 4.2500	$ 1,317,500	$ 4.0110	$ 1,243,410	$ 4.0110	$ 1,243,410	$ -	$ 0.2910	$ 90,210	$ 1,333,620
5	10/xx/2014		32	320,000	$ 4.2500	$ 1,360,000	$ 4.0110	$ 1,283,520	$ 4.0110	$ 1,283,520	$ -	$ 0.2910	$ 93,120	$ 1,376,640
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total	Total		155	1,550,000		$ 6,737,500		$ 6,217,050		$ 6,217,050	$ -		$ 450,510	$ 6,667,560
						$ 4.3468		$ 4.0110		$ 4.0110	$ -		$ 0.0669	$ 4.3017
NNG-Cons	126	81.29%	126	1,260,000	$ 4.3468	$ 5,476,935	$ 4.0110	$ 5,053,860	$ 4.0110	$ 5,053,860	$ -	$ 0.2907	$ 366,221	$ 5,420,081
Other-Cons	29	18.71%	29	290,000	$ 4.3468	$ 1,260,565	$ 4.0110	$ 1,163,190	$ 4.0110	$ 1,163,190	$ -	$ 0.2907	$ 84,289	$ 1,247,479
Total	155	100.0%	155	1,550,000	$ 4.3468	$ 6,737,500	$ 4.0110	$ 6,217,050	$ 3.7060	$ 6,217,050	$ -	$ 0.2907	$ 450,510	$ 6,667,560

			Feb-15											
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	06/18/14		28	280,000	$ 5.0000	$ 1,400,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3750	$ 105,000	$ 1,225,280
2	07/18/14		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3050	$ 85,400	$ 1,205,680
3	8/xx/2014		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3400	$ 95,200	$ 1,215,480
4	9/xx/2014		28	280,000	$ 4.2500	$ 1,190,000	$ 4.0010	$ 1,120,280	$ 4.0010	$ 1,120,280	$ -	$ 0.3400	$ 95,200	$ 1,215,480
5	10/xx/2014		29	290,000	$ 4.2500	$ 1,232,500	$ 4.0010	$ 1,160,290	$ 4.0010	$ 1,160,290	$ -	$ 0.3400	$ 98,600	$ 1,258,890
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			141	1,410,000		$ 6,202,500		$ 5,641,410		$ 5,641,410	$ -		$ 479,400	$ 6,120,810
						$ 4.3989		$ 4.0010		$ 4.0010	$ -		$ 0.0773	$ 4.3410
NNG-Cons	115	81.56%	115	1,150,000	$ 4.3989	$ 5,058,777	$ 4.0010	$ 4,601,150	$ 3.6613	$ 4,601,150	$ -	$ 0.3400	$ 391,000	$ 4,992,150
Other-Cons	26	18.44%	26	260,000	$ 4.3989	$ 1,143,723	$ 4.0010	$ 1,040,260	$ 3.8902	$ 1,040,260	$ -	$ 0.3400	$ 88,400	$ 1,128,660
Total	141	100.0%	141	1,410,000	$ 4.3989	$ 6,202,500	$ 4.0010	$ 5,641,410	$ 3.7060	$ 5,641,410	$ -	$ 0.3400	$ 479,400	$ 6,120,810

			Mar-15											
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	06/10/14		23	230,000	$ 4.7500	$ 1,092,500	$ 3.8690	$ 889,870	$ 3.8690	$ 889,870	$ -	$ 0.3960	$ 91,080	$ 980,950
2	07/08/14		24	240,000	$ 4.2500	$ 1,020,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4110	$ 98,640	$ 1,027,200
3	8/xx/2014		24	240,000	$ 4.0000	$ 960,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4035	$ 96,840	$ 1,025,400
4	9/xx/2014		24	240,000	$ 4.0000	$ 960,000	$ 3.8690	$ 928,560	$ 3.8690	$ 928,560	$ -	$ 0.4035	$ 96,840	$ 1,025,400
5	10/xx/2014		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8690	$ 967,250	$ 3.8690	$ 967,250	$ -	$ 0.4035	$ 100,875	$ 1,068,125
6				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			120	1,200,000		$ 5,032,500		$ 4,642,800		$ 4,642,800	$ -		$ 484,275	$ 5,127,075
						$ 4.1938		$ 3.8690		$ 3.8690	$ -		$ 0.0962	$ 4.2726
NNG-Cons	96	80.00%	96	960,000	$ 4.1938	$ 4,026,000	$ 3.8690	$ 3,714,240	$ 3.6613	$ 3,714,240	$ -	$ 0.4036	$ 387,420	$ 4,101,660
Other-Cons	24	20.00%	24	240,000	$ 4.1938	$ 1,006,500	$ 3.8690	$ 928,560	$ 3.8902	$ 928,560	$ -	$ 0.4036	$ 96,855	$ 1,025,415
Total	120	100.0%	120	1,200,000	$ 4.1938	$ 5,032,500	$ 3.8690	$ 4,642,800	$ 3.7060	$ 4,642,800	$ -	$ 0.4036	$ 484,275	$ 5,127,075

			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			123	1,230,000	$ 4.8923	$ 6,017,500	$ 3.9464	$ 4,854,060	19.678	$ 4,854,060	$ -	$ 0.3248	$ 399,540	$ 5,253,600
2			126	1,260,000	$ 4.1984	$ 5,290,000	$ 3.9462	$ 4,972,250	19.678	$ 4,972,250	$ -	$ 0.2803	$ 353,230	$ 5,325,480
3			126	1,260,000	$ 4.1171	$ 5,187,500	$ 3.9462	$ 4,972,250	19.678	$ 4,972,250	$ -	$ 0.3026	$ 381,280	$ 5,353,530
4			128	1,280,000	$ 4.1152	$ 5,267,500	$ 3.9449	$ 5,049,410	19.678	$ 5,049,410	$ -	$ 0.3015	$ 385,880	$ 5,435,290
5			132	1,320,000	$ 4.1155	$ 5,432,500	$ 3.9452	$ 5,207,610	19.678	$ 5,207,610	$ -	$ 0.3019	$ 398,530	$ 5,606,140
6														
7														
8														
9														
10														
11														
12														
13														
14														
15														
Total			635	6,350,000		$ 27,195,000		$ 25,055,580		$ 25,055,580	$ -		$ 1,918,460	$ 26,974,040
						$ 4.2827		$ 3.9458		$ 3.9458	$ -		$ 0.0705	$ 4.2479
NNG-Cons	513	80.79%	513	5,130,000	$ 4.2834	$ 21,973,622	$ 3.9461	$ 20,243,570	18.9340482	$ 20,243,570	$ -	$ 0.3021	$ 1,549,901	$ 21,793,471
Other-Cons	122	19.21%	122	1,220,000	$ 4.2798	$ 5,221,378	$ 3.9443	$ 4,812,010	19.6205512	$ 4,812,010	$ -	$ 0.3021	$ 368,559	$ 5,180,569
Total	635	100.0%	635	6,350,000	$ 4.2827	$ 27,195,000	$ 3.9458	$ 25,055,580	$ 3.7060	$ 25,055,580	$ -	$ 0.3021	$ 1,918,460	$ 26,974,040