MINNESOTA
DEPARTMENT OF
COMMERCE

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November 15, 2011

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket Nos. G007/M-10-1166, G011/M-10-1167, and G011/M-10-1168[1]

Dear Dr. Haar:

Attached are the *Response Comments* of the Minnesota Department of Commerce, Division of Energy Resources (DOC or Department) in the following matter:

> Requests (*Petitions*) submitted by Minnesota Energy Resources Corporation-PNG and Minnesota Energy Resources Corporation-NMU (MERC or Company) for approval of changes in demand entitlements on its NMU Purchased Gas Adjustment (PGA) system (10-1166), Great Lakes Gas Transmission (Great Lakes) PGA system (10-1167), and Northern Natural Gas (Northern) PGA system (10-1168).

The Petitions were filed on November 1, 2010 by:

> Greg Walters
> Regulatory and Legislative Affairs Manager
> Minnesota Energy Resources Corporation
> 519 1st Avenue SW
> PO Box 6538
> Rochester, MN 55903-6538

The Department filed its *Comments* regarding MERC's Northern PGA system on January 4, 2011, MERC's NMU PGA system demand entitlement filing on February 18, 2011, and its *Comments* regarding MERC's Great Lakes PGA system demand entitlement filing on March 16, 2011. In each of these filings, the Department withheld recommendation, recommended disallowance of cost, and requested that MERC provide additional information in *Reply Comments*. The DOC concludes that a response to MERC's *Reply Comments* is necessary to establish a complete record in this matter.

[1] The Department notes that no further comments are needed in MERC's fourth demand entitlement filing, Docket No. G011/M-10-1169, since the Department recommends approval of MERC's filing.

As such, the Department requests that the Minnesota Public Utilities Commission (Commission) accept these *Response Comments* to MERC's *Reply Comments*.[2] Given similar recommendations in each filing, the DOC files a single set of *Response Comments* for all three dockets.

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ ADAM JOHN HEINEN
Rates Analyst
651-296-6329

AJH/sm
Attachment

[2] The Department notes that the analyses within these comments were completed shortly after the shutdown of Minnesota government ended. However, DOC management needed additional time to complete its review and apologizes for the delay.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE,
DIVISION OF ENERGY RESOURCES

DOCKET NO. G007/M-10-1166, G011/M-10-1167, and G011/M-10-1168

I. BACKGROUND

The following rounds of comments have been submitted to the Minnesota Public Utilities Commission (Commission) in Minnesota Energy Resources Corporation-NMU's and Minnesota Energy Resources Corporation-PNG's (MERC or Company) 2010-2011 demand entitlement filings for its NMU Purchased Gas Adjustment (PGA) system, Great Lakes Transmission (Great Lakes) PGA system, Northern Natural Gas (Northern) PGA system, and Viking PGA system:

- November 1, 2010, MERC's initial *Petition* in each PGA system demand entitlement filing;
- January 3, 2011, Minnesota Department of Commerce, Division of Energy Resources' (DOC or Department)[3] *Comments* in the Northern PGA system demand entitlement filing (Docket No. G011/M-10-1068);
- February 18, 2011, DOC *Comments* in the NMU PGA system demand entitlement filing (Docket No. G007/M-10-1166);
- March 16, 2011, DOC *Comments* in the Great Lakes PGA system demand entitlement filing (Docket No. G011/M-10-1167);
- April 22, 2011, DOC *Comments* in the Viking PGA system demand entitlement filing (Docket No. G011/M-10-1169);
- May 2, 2011, MERC's *Reply Comments* in the Northern, Great Lakes, NMU and Viking PGA system demand entitlement filings; and
- November 14, 2011, Department's *Response Comments*.

[3] When the Department filed these *Comments*, and the two other comments discussed below, it was referred to as the Minnesota Office of Energy Security (OES). The name of the agency has been subsequently changed but the statutory duties are the same.

The Department notes that issues pertaining to MERC's Viking Gas Transmission (Viking) PGA demand entitlement filing have been resolved since the DOC accepted the Company's demand entitlement filing, as discussed below. However, since MERC's demand entitlement analyses are related in many ways, the Department's *Response Comments* may relate, at least in part, to the Company's Viking PGA.

II. THE DEPARTMENT'S RESPONSE TO MERC'S *REPLY COMMENTS*

MERC's response to the Department's various demand entitlement filings include topics that are interrelated and specific to each demand entitlement filing. Each topic is discussed separately below and, if a topic is relevant to multiple PGA systems, the DOC acknowledges that fact at the beginning of the section. In addition, while reviewing the Company's *Reply Comments*, the current record in these dockets, and the records in other demand entitlement filings, the Department also makes comments related to the general nature of demand entitlement filings.

A. DOC RESPONSE REGARDING THE COMPANY'S BISON CONTRACT

In the Department's Northern PGA and NMU PGA *Comments*, the Department expressed concerns regarding MERC's Bison Contract. Specifically, the DOC expressed concerns regarding the demand costs associated with this contract and the Company's process involved with entering into this agreement. In particular, the Department requested that the Company provide detailed historical data and natural gas hub price determinants related to the Bison Contract during the time period in 2008 when the Company was considering entering into this contract, along with the following:

- A full discussion detailing whether MERC considered the impacts of changes in the natural gas market dynamics that occurred around July 1, 2008 before entering into the Bison Contract on August 21, 2008;
- A full discussion detailing whether MERC undertook an analysis similar to what was requested in DOC Information Request No. 7 (included as DOC Attachment 3 in Docket No. G007/M-10-1169) when considering entering into the Bison Contract; and
- A full discussion detailing whether volumes associated with the Bison Contract can be sold in the capacity release market and, if so, the value that MERC anticipates can be achieved for these volumes over the life of the contract.

The Company provided a detailed response to these concerns and additional analysis in both its NMU and Northern PGA system *Reply Comments*. MERC provided an overview of general natural gas market conditions during 2008 and reiterated that the primary reason for entering into the Bison Contract was to diversify gas supply on its system and increase reliability. In its analysis, MERC also mentioned that, when analyzing the Bison Contract, it is important to determine both the transportation and commodity costs associated with delivering gas to customers. As stated in its *Reply Comments*, the Company agrees with the Department that the demand resource per customer increases with the Bison Contract; however, since the contract allows MERC to procure gas priced off of the Colorado Interstate Gas (CIG) index price, the delivered cost of gas, including the commodity cost, was the least-cost option when the Company decided to enter into the contract. The Company also provided the detailed historical price data from 2008 requested by the Department.

The Department appreciates the additional information provided by MERC. This information, including detailed daily price data, suggests that, despite the relatively high demand costs, the Bison and Northern Border Pipeline (NBPL) Contracts were not unreasonable when entered into by MERC in 2008. However, the Department continues to have concerns regarding responses by the Company and the overall approach used by MERC when examining these contracts.

Given that the costs associated with the Bison Contract are not unreasonable, the Department does not recommend disallowance of the costs; instead, the Department focuses its concerns in a forward-looking manner. Based on the information, or lack of information as it relates to the above bullet points, in this record, it appears that the process used by MERC to evaluate the Bison Contract in 2008 was inadequate, such that, if MERC were to use such an approach in the future, it will be necessary to investigate further whether the incurred costs are prudent or whether the costs should be disallowed. As noted in the Company's *Reply Comments*, the only quantitative analysis shown to the Commission in Docket No. G007,011/M-08-698 was based on price data from a single date, May 19, 2008.

The Department appreciates the average cost analysis provided by the Company in its May 2, 2011 *Reply Comments*; however, this information should be provided in future initial petitions and not completed after the fact. Basing decisions about a contract on a single day, as it appears that MERC did, is inappropriate since it does not provide an adequate representation of costs associated with a contract. In addition, the lack of response from the Company regarding changes to natural gas prices around July 1, 2008 suggests that once MERC decided to pursue the Bison Contract it did not effectively monitor market developments. Although MERC's primary goal was supply diversification, this goal should not be done at all costs. The process used by MERC when acquiring the Bison Contract put ratepayers at risk in terms of price and should be modified going forward.

In particular, MERC should maintain, at a minimum, the following information:

- Daily price data;
- Cost benefit analyses if the goal is to justify diversification;
- Other procurement options considered;
- If there is a change in circumstance, what was done or, if nothing was done, why nothing was done; and
- Analysis based on more than a single day.

Beyond the issues discussed above, the Department also asked that the Company investigate whether capacity release would be available on the Bison Pipeline. In its *Reply Comments*, MERC stated that there currently is not a capacity market on Bison, but a party could attempt to acquire released capacity. The Company further stated that it has fully accounted for its 50,000 Dekatherms of capacity through January 2013 and 37,500 Dekatherms of its capacity through January 2014. MERC also stated that it is currently delivering these volumes to Ventura and that they are being used by MERC customers. Based on this information, the Department does not have any additional concerns related to this topic at this time.

Based on the information provided by the Company in the NMU and Northern *Reply Comments*, the Department concludes that the costs associated with the Company's Bison and NBPL contract are acceptable at this time. Although there were issues involved with the Company's evaluation process that should be corrected in the future, an analysis of historical daily prices show that, when total price is considered, the Bison Contract did not harm ratepayers and was prudently incurred at the time. The greater issue at this point is how these Bison and NBPL Contract costs should be recovered.

As noted by the Company in its *Initial Petitions*, the Bison Contract, and its associated volumes, are not included in the calculation of MERC's design-day or peak day which would make them similar to non-heating season demand contracts. However, it is important to note that at several points in this record, and in the original Bison Pipeline docket, the Company has stated that one of the benefits of the Bison Contract is that it allows MERC to procure lower priced gas from the Rocky Mountains. If the goal, in part, of the Bison Contract is to diversify supply procurement and allow the utility to access lower priced gas, then it would appear that this contract would produce benefits for all MERC ratepayers, not just firm customers. In that case, then the Bison Contract would be similar to a storage contract, which means that the costs associated with the contract should be recovered through the commodity portion of the monthly PGA. If, on the other hand, this contract is specifically intended to reserve capacity for firm customers then it should be recovered as demand costs. However, given the size of the Bison Contract, if the volumes are intended solely for firm use, it would raise the possibility that the Company has redundant demand contracts and, as such, ratepayers are being charged too much for either non-heating season demand costs, peak day demand costs, or both.

The Department includes, as shown in Attachments R-1 and R-2 to these comments, the calculation of PGA costs associated with including the Bison Contract in the commodity portion of the PGA for both the NMU PGA and MERC-PNG Northern PGA. The calculation of PGA costs with the Bison Contract included in the demand portion of the PGA are included as Attachment 4, Page 1, and Attachment 11 to MERC's originally filed NMU and Northern demand entitlement petitions, respectively. Without additional supporting information from the Company, given the Bison Contract's stated goal of allowing MERC to access lower priced natural gas, the Department recommends that the Commission require MERC to recover costs associated with the Bison Contract through the commodity portion of the monthly PGA, which is charged to firm and interruptible customers and not the demand portion, charged only to firm customers. Currently, the Company recovers costs associated with its hedging Call Options through the commodity portion of the PGA since all customers benefit from the price stability associated with financial hedging and MERC has agreed to transition recovery of storage-related costs to the commodity portion of the PGA since all customers benefit from storage contracts.

Finally, in regards to the Bison Contract, the Department noted in its *Comments* that the contract length associated with the Bison Contract did not reflect actual pipeline operations. In particular, the Company's original *Petitions* stated that the pipeline would enter service on, or about, December 15, 2010, but news releases reviewed by the Department stated that the pipeline did not in fact enter service until the middle of January 2011. Given this information, the Department recommended that the Company clarify this issue in its *Reply Comments* and refund any difference between revenues already collected and the correct amount in MERC's upcoming true-up filing.

In its *Reply Comments*, the Company acknowledged that the Bison Pipeline did not enter service until January 12, 2011. The Company further stated that it agrees with the Department's recommendations and that it would make the necessary recovery change beginning with the June 2011 PGA filing and that any over-recoveries prior to the change in the PGA would be trued up in the Company's 2011 AAA filing. The Department reviewed MERC's monthly PGA filings beginning in June 2011 and notes that the Company has correctly modified the length of this contract and, as such, the Department does not have any additional comments on this issue.

B. DOC COMMENTS REGARDING THE COMPANY'S DESIGN-DAY ANALYSIS AND RESERVE MARGIN

In its *Comments* in each of the demand entitlement filings, the Department expressed confidence that MERC's design-day studies produced results that ensure sufficient capacity to meet need on a peak day, but the Department was concerned that the reserve margins created by these studies were too large and the Company may have excessive demand entitlements. Given these concerns with the reserve margins, the Department withheld recommendations on the reasonableness of the design-day analysis until the Company provided additional information validating the reasonableness of its analyses and recommended disallowance of revenues in excess of the reserve margin recommended for approval by the Department in the 2009-2010 demand entitlement filings.

In each of its *Reply Comments*, MERC provided an historical analysis of design-day growth and how it compares to recent growth patterns, a discussion of current system usage, known issues with its design-day analysis, and responses to the DOC's concerns regarding the Company's reserve margins.

The Company provided, in each of its *Reply Comments*, an historical analysis by PGA system going back to the early and mid-1990s. For each of its PGA systems, MERC showed consistent yearly growth in the design-day requirement until the last few years when growth leveled off. MERC speculates that, since its design-day analysis is based on historical daily data from the three heating seasons directly prior to the forecasting period (*i.e.,* current heating season), general economic conditions have possibly biased the design-day forecast downward. In particular, the Company states that 2009 data was an anomaly and was contributing to the low forecast number. In addition to low forecasting as a result of the recession, MERC further stated that overall system growth has been slow to recover even with the conclusion of the recession. Given the slow recovery in sales, MERC also discussed the risks associated with turning back capacity since the economy could continue to grow, or grow at a greater rate, and the Company may be unable to reacquire this capacity.

In terms of known issues with the design-day analysis, the Company provides a lengthy discussion regarding the difficulties it encounters in estimating non-firm sales. Since MERC does not have actual firm data, it uses total system throughput and then estimates non-firm usage to estimate firm usage. Without knowing the individual usage characteristics of each non-firm customer, the Company must make assumptions in terms of usage patterns and, in the case of its design-day analysis, MERC assumes that non-firm customers operate on a 20-day a month schedule. Using this assumption as the basis for its analysis, MERC shows that changes in usage pattern (15-day load profile or 30-day load profile) can have a significant impact on non-firm usage and, thus, the design-day requirement and reserve margin.

The Department and MERC have been working cooperatively on this issue in recent demand entitlement filings. The DOC agrees that having to estimate non-firm usage adds volatility to the design-day forecast and, as such, an additional level of forecasting error is introduced into the analyses. As noted by the Company in its *Reply Comments*, MERC received Commission approval in its 2008 rate case, Docket No. G007,011/GR-08-835, to install telemetry on all its non-firm customers (excluding farm taps). Once the telemetry is fully installed, and operational, the Company will be able to adequately track non-firm usage and more effectively forecast peak day use by firm customers. These data should be available in the coming years and, once these data is available, the issue of estimating non-firm usage will be resolved.

The Company also provides additional discussion regarding the high reserve margins on its Northern, NMU, and Great Lakes PGA systems. In this discussion, MERC reiterates its concerns regarding slow economic growth and lack of actual non-firm data. The Company also discusses its responsibility in terms of balancing the overall MERC system. In particular, the Company states that it does not contract for firm capacity to meet non-firm usage, but it still has the responsibility to balance the entire system with respect to each interstate pipeline. The Company must deliver enough gas to ensure service for firm, non-firm, and any third-party transportation volumes in excess of third party delivered supply. Although the Department understands the Company's obligation to balance its system, this obligation should not be used as an excuse to procure additional demand entitlements. If a utility were to balance its system in this manner then firm customers would be expected to pay the full cost of balancing the system even if an imbalance event was caused by interruptible or transport customers using excess capacity. The Department recommends that the Company clarify its statement and provide detailed evidence in subsequent demand entitlement filings, including a supplement to the 2011 demand filing, assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties.

Based on its review of MERC's *Reply Comments*, the Department concludes that MERC's design-day analyses are appropriate in this proceeding and that these analyses likely produce results that ensure sufficient firm capacity on a peak day. In addition, the Department concludes that the Company's reserve margins are reasonable given the Company's comments regarding current and past economic conditions. Finally, the Department withdrawals its original recommendation that costs in excess of the reserve margin in the 2009-2010 demand entitlement filings be disallowed since the Company has adequately explained, as detailed above, why these costs were incurred. Although the Department remains concerned about the large reserve margins, it acknowledges that these reserve margins are related to circumstances outside of the Company's control and also the difficulties inherent in estimating the design day. In an effort to improve future demand entitlement filings, the Department recommends that MERC consider the following when preparing future filings:

- Inclusion of determinants in its design-day models that adequately account for any, and all, impact on usage associated with economic conditions; and
- Detailed explanations of any, and all, causes of unexpected changes in usage that may impact the design-day calculation and what, if any, modifications the Company made to its design day numbers.

C. DOC COMMENTS REGARDING THE NATURE OF DEMAND ENTITLEMENT FILINGS

Through the course of examining the various demand entitlement petitions filed by Minnesota utilities for the 2010-2011 heating season, the Department observed, generally speaking, that utilities had relatively large reserve margins. In response to queries by the DOC into this topic, the utilities responded that the reserve margins were the result, in part, of low economic growth, being required to purchase capacity several years in advance, along with concerns about releasing capacity back to the interstate pipelines. The Department appreciates these comments, which help explain how Minnesota utilities create their demand entitlement filings. These discussions have also illustrated some weaknesses in the current demand entitlement rules that the Department believe require consideration. While contemplating these concerns, the Department concludes that issues with the demand entitlement filings fall into two distinct categories: 1) when the filing is made; and 2) what costs relate to a given demand entitlement. The Department discusses each of these separately below.

In terms of when a demand entitlement filing is made, Minnesota Rules 7825.2910, Subp. 2 states the following:

> Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

It is evident from the above rule that there is no prescribed date when a demand entitlement filing must be made, just that it is necessary when a utility changes, or modifies, its demand portfolio. Given the nature of natural gas purchasing, demand contracts typically change starting November 1 of each calendar year, which is the reason why Minnesota utilities generally make their demand entitlement filings on, or about, November 1st each year. The problem with the current arrangement, where utilities make the demand entitlement filing concurrent with the change in demand levels, is that it does not provide the Department, and Commission, adequate time to review the reasonableness of these filings and, if necessary, make adjustments that could help protect ratepayers during the heating season. To the Department's knowledge, there have been no firm deliverability issues recently; however, if a deliverability issue were to occur as a result of insufficient entitlement levels it is unlikely, even under the most accelerated timelines, that the Department could complete its analysis, the Commission make a ruling requiring a utility to procure additional capacity, and the utility acquire this capacity prior to the typical peak of heating season consumption (*i.e.,* late January through middle February) based on the current demand entitlement system.

Since Minnesota Rules do not set a specific date when a demand entitlement filing is due, the Department believes that a modification in how utilities make these filings may be necessary and could improve firm reliability going-forward. Based on various conversations with utilities, the Department is under the impression that entitlement levels for a given heating season are generally set several months before the beginning of the heating season. For example, if the gas utilities have a reasonable idea of what entitlements they will be purchasing, and the corresponding volume amount, in June, the Department believes it may be reasonable for the utility to file its demand entitlement filing in July or August. Under this scenario, the Department and Commission would have significantly more time to review and comment on the filing and may be able to modify, if necessary, the amount of entitlements such that ratepayers would be adequately protected and would be charged reasonable rates. Given the above discussion, the Department recommends that the Commission require that MERC provide in its next demand entitlement filing a full discussion commenting on the reasonableness of the Department's proposal that the demand entitlement filing date be changed and a detailed explanation of when, on average, during the year it conducts its design-day analyses and subsequently procures demand entitlements for the upcoming heating season.

The Department also recommends that the Commission require all Minnesota regulated gas utilities provide a discussion in their next demand entitlement filing commenting on the reasonableness of the Department's proposal that the demand entitlement filing date be changed and a detailed explanation of when, on average, during the year the utility conducts its design-day analysis and subsequently procures demand entitlements for the upcoming heating season.

In terms of what costs and demand entitlement changes should be included in the annual filing, the Department believes it is necessary to open a discussion on how various demand entitlement contracts are analyzed. Currently, when the utilities create their demand entitlement filings, these filings are based on the design-day study, which is used to project peak usage for the upcoming heating season. As noted above, the utilities have stated in their various comments that certain amounts of capacity have been purchased in anticipation of future need (*i.e.,* need beyond the upcoming heating season) or they have been required to purchase additional capacity, that they will eventually grow into, by the interstate pipeline (*i.e.,* a utility needs 175 Mcf/day but the interstate pipeline only sells capacity in 250 Mcf/day increments). Since the design-day study is based on expected conditions during the upcoming heating season, these assertions raise the question of whether incremental capacity purchased by the utility, that will not be need until future heating seasons, should be recovered from ratepayers during a period where it is not needed to serve firm needs.

Through its review of MERC's demand entitlement filings, and demand entitlement filings from other utilities, the Department has been unable to identify any discussions regarding the reasonableness of this current recovery practice. Given this concern and lack of supporting discussion, the Department recommends that the Commission require MERC to provide in its next demand entitlement filing a full discussion commenting on how the Company determines whether additional capacity, beyond the amount calculated in the design-day analysis, is reasonable and should be recovered from firm customers during the current heating season. The Company should also provide in its next demand entitlement filing a discussion detailing whether MERC believes there is an effective mechanism to alleviate these cost recovery concerns and whether it has discussed with the various interstate pipelines methods through which procured volumes can be phased in when they are needed and not as a whole group.

The Department also recommends that the Commission require all other Minnesota regulated gas utilities provide, in their next demand entitlement filings, a detailed discussion explaining how the utility determines whether additional capacity, beyond the amount calculated in the design-day analysis, is reasonable and should be recovered from firm customers during the current heating season. In addition, each utility should provide a discussion detailing whether they believe there is an effective mechanism to alleviate the issue of excess capacity during a given heating season, and the recovery of costs associated with these volumes, and whether the utility has discussed with the various interstate pipeline methods through which procured volumes can be phased in when they are needed and not as a whole group.

III. THE DOC'S CONCLUSION AND RECOMMENDATIONS

Based on its review of MERC's *Reply Comments*, the Department withdrawals its original recommendation that costs in excess of the reserve margin in the 2009-2010 demand entitlement filings be disallowed since the Company has adequately explained, as detailed above, why these costs were incurred.

The DOC also recommends that the Commission:

- approve MERC-NMU's demand entitlement level;
- approve MERC-PNG's Northern PGA system demand entitlement level;
- approve MERC-PNG's Great Lakes PGA system demand entitlement level;
- approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going-forward basis;
- approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going-forward basis;

- approve the PGA recovery of costs associated with MERC-PNG's Great Lakes PGA system proposed demand entitlement level effective November 1, 2010;

The Department recommends that MERC clarify its statements regarding system balancing and provide detailed evidence in subsequent demand entitlement filings assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties. In addition, the DOC recommends that MERC consider the following when preparing future demand entitlement filings:

- Inclusion of determinants in its design-day models that adequately account for any, and all, impact on usage associated with economic conditions; and
- Detailed explanations of any, and all, causes of unexpected changes in usage that may impact the design-day calculation and what, if any, modifications the Company made to its design day numbers.

Following the Commission's November 10, 2011 discussion on hedging, the Department discussed with some of the natural gas utilities present the idea of meeting separately with each utility in early 2012 to talk about the utility's hedging plan for 2012-13. The Department also intends to discuss with MERC and all Minnesota regulated natural gas utilities the following:

- the Department's proposal that the demand entitlement filing date be changed and a detailed explanation of when, on average, during the year the utility conducts its design-day analysis and subsequently procures demand entitlements for the upcoming heating season;
- how the utility determines whether additional capacity, beyond the amount calculated in the design-day analysis, is reasonable and should be recovered from firm customers during the current heating season; and
- whether the utility believes there is an effective mechanism to alleviate the issue of excess capacity during a given heating season, and the recovery of costs associated with these volumes, and whether the utility has discussed with the various interstate pipeline methods through which procured volumes can be phased in when they are needed rather than in advance of when the volumes are needed.

/sm

DOC Attachment R-1

Effect on MERC-NMU PGA Costs of Accounting for the Bison Contract in the Commodity Portion of the PGA

General Service	Last Rate Case GR-08-835	Last Demand Filing M-08-1329	October PGA 2009	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.7875	-55.59%	-42.42%	2.57%	$0.0947
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0023	-12.24%	-10.52%	-8.30%	($0.0907)
Margin	$2.3126	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.1024	-40.73%	-29.05%	0.06%	$0.0040
Average Annual Use	**140**	**140**	**140**	**140**				
Average Annual Cost of Gas	$1,677.68	$1,401.47	$993.78	$994.34	-40.73%	-29.05%	0.06%	$0.56

Large General Service	Last Rate Case GR-08-835	Last Demand Filing M-08-1329	October PGA 2009	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.7875	-55.59%	-42.42%	2.57%	$0.0947
Demand Cost	$1.1420	$1.1201	$1.0930	$1.0023	-12.24%	-10.52%	-8.30%	($0.0907)
Margin	$2.3126	$2.3126	$2.3126	$2.3126	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$11.9834	$10.0105	$7.0984	$7.1024	-40.73%	-29.05%	0.06%	$0.0040
Average Annual Use	**6,917**	**6,917**	**6,917**	**6,917**				
Average Annual Cost of Gas	$82,889.18	$69,242.63	$49,099.63	$49,127.30	-40.73%	-29.05%	0.06%	$27.67

SV Interruptible Service	Last Rate Case GR-08-835	Last Demand Filing M-08-1329	October PGA 2009	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.7875	-55.59%	-42.42%	2.57%	$0.0947
Commodity Margin	$1.0127	$0.8500	$1.0127	$1.0127	0.00%	19.14%	0.00%	$0.0000
Total Cost of Gas	$9.5415	$7.4278	$4.7055	$4.8002	-49.69%	-35.37%	2.01%	$0.0947
Average Annual Use	**6,333**	**6,333**	**6,333**	**6,333**				
Average Annual Cost of Gas	$60,426.32	$47,040.26	$29,799.93	$30,399.86	-49.69%	-35.37%	2.01%	$599.93

LV Interruptible Service	Last Rate Case GR-08-835	Last Demand Filing M-08-1329	October PGA 2009	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$8.5288	$6.5778	$3.6928	$3.7875	-55.59%	-42.42%	2.57%	$0.0947
Commodity Margin	$0.3395	$0.2850	$0.3395	$0.3395	0.00%	19.12%	0.00%	$0.0000
Total Cost of Gas	$8.8683	$6.8628	$4.0323	$4.1270	-53.46%	-39.86%	2.35%	$0.0947
Average Annual Use	**37,114**	**37,114**	**37,114**	**37,114**				
Average Annual Cost of Gas	$329,138.09	$254,705.96	$149,654.78	$153,170.59	-53.46%	-39.86%	2.35%	$3,515.81

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.0947	2.57%	($0.0907)	-8.30%	$0.0040	0.06%	$0.56
Large General Service	$0.0947	2.57%	($0.0907)	-8.30%	$0.0040	0.06%	$27.67
SV Interruptible Service	$0.0947	2.57%	$0.0000	0.00%	$0.0947	2.01%	$599.93
LV Interruptible Service	$0.0947	2.57%	$0.0000	0.00%	$0.0947	2.35%	$3,515.81

Note: The rate impact of moving the Bison Contract is based on the contract duration in MERC's original filing.

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

DOC Attachment R-2
Rate Impact of Moving MERC's Bison Contract to the Commodity Portion of the PGA for MERC-PNG Northern

1) General Service: Avg. Annual Use:			125 Mcf					
Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-09-1284	Most Recent PGA Oct 1/10	Oct 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$3.7399	$3.9286	$3.9879	-54.17%	6.63%	1.51%	$0.0593
Demand Rate	$1.1197	$1.0883	$1.0362	$1.6033	43.19%	47.33%	54.73%	$0.5671
Margin	$1.6263	$1.6263	$1.7746	$1.7746	9.12%	9.12%	0.00%	$0.0000
Total Recovery	$11.4474	$6.4545	$6.7394	$7.3658	-35.66%	14.12%	9.29%	$0.6264
Avg. Annual Bill*	$1,430.93	$806.81	$842.43	$920.73	-35.66%	14.12%	9.29%	$78.3000
Effect of proposed commodity change on average annual bills:								$7.4075
Effect of proposed demand change on average annual bills:								$70.8925
2) Small Volume Interruptible: Avg. Annual Use:			**4,080 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-09-1284	Most Recent PGA Oct 1/10	Oct 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$3.7399	$3.9286	$3.9879	-54.17%	6.63%	1.51%	$0.0593
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$1.2434	$0.9000	$1.1681	$1.1681	-6.06%	29.79%	0.00%	$0.0000
Total Recovery	$9.9448	$4.6399	$5.0967	$5.1560	-48.15%	11.12%	1.16%	$0.0593
Avg. Annual Bill*	$40,574.78	$18,930.79	$20,794.54	$21,036.32	-48.15%	11.12%	1.16%	$241.7808
Effect of proposed commodity change on average annual bills:								$241.7808
Effect of proposed demand change on average annual bills:								$0.0000
3) Large Volume Interruptible: Avg. Annual Use:			**19,053 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-09-1284	Most Recent PGA Oct 1/10	Oct 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$3.7399	$3.9286	$3.9879	-54.17%	6.63%	1.51%	$0.0593
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.3592	$0.3592	$0.3248	$0.3248	-9.58%	-9.58%	0.00%	$0.0000
Total Recovery	$9.0606	$4.0991	$4.2534	$4.3127	-52.40%	5.21%	1.39%	$0.0593
Avg. Annual Bill*	$172,631.61	$78,100.15	$81,040.03	$82,169.11	-52.40%	5.21%	1.39%	$1,129.0808
Effect of proposed commodity change on average annual bills:								$1,129.0808
Effect of proposed demand change on average annual bills:								$0.0000
4) Small Volume Firm: Avg. Annual Use:			**4,080 Mcf (MERC-PNG currently has no customers in this class.)**					
Avg. Annual CD Volumes:			**25 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-09-1284	Most Recent PGA Oct 1/10	Oct 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$3.7399	$3.9286	$3.9879	-54.17%	6.63%	1.51%	$0.0593
Demand Rate	$13.4177	$12.0195	$9.3592	$9.3592	-30.25%	-22.13%	0.00%	$0.0000
Comm. Margin	$1.2434	$1.2434	$1.1681	$1.1681	-6.06%	-6.06%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$2.0724	$2.0724	$2.0724	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.9448	$4.9833	$5.0967	$5.1560	-48.15%	3.46%	1.16%	$0.0593
Total Demand Cost	$15.4901	$14.0919	$11.4316	$11.4316	-26.20%	-18.88%	0.00%	$0.0000
Avg. Annual Bill*	$40,962.04	$20,684.16	$21,080.33	$21,322.11	-47.95%	3.08%	1.15%	$241.7808
Effect of proposed commodity change on average annual bills:								$241.7808
Effect of proposed demand change on average annual bills:								$0.0000
5) Large Volume Firm: Avg. Annual Use:			**14,841 Mcf (MERC-PNG currently has no customers in this class.)**					
Avg. Annual CD Units:			**75 Mcf**					
Recovery	Last Base Cost of G G011/MR-08 836	Last Demand Change M-09-1284	Most Recent PGA Oct 1/10	Oct 1/10 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$1.6138	$3.7399	$3.9286	$3.9879	147.11%	6.63%	1.51%	$0.0593
Demand Rate	$13.4177	$12.0195	$9.3592	$9.3592	-30.25%	-22.13%	0.00%	$0.0000
Comm. Margin	$0.3770	$0.2600	$0.3248	$0.3248	-13.85%	24.92%	0.00%	$0.0000
LV Dem. Margin	$1.5000	$1.2000	$1.6579	$1.4000	-6.67%	16.67%	-15.56%	($0.2579)
Total Commodity Cost	$1.9908	$3.9999	$4.2534	$4.3127	116.63%	7.82%	1.39%	$0.0593
Total Demand Cost	$14.9177	$13.2195	$11.0171	$10.7592	-27.88%	-18.61%	-2.34%	($0.2579)
Avg. Annual Bill*	$30,664.29	$60,353.98	$63,950.99	$64,811.13	111.36%	7.39%	1.34%	$860.1352
Effect of proposed commodity change on average annual bills:								$879.4777
Effect of proposed demand change on average annual bills:								$0.0000

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

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.0593	1.51%	$0.5671	54.73%	0.6264		9.29%
Sm Vol Inter. Service	$0.0593	1.51%	$0.0000	0.00%	0.0593		1.16%
Lrg Vol Inter. Service	$0.0593	1.51%	$0.0000	0.00%	0.0593		1.39%
Sm Vol Joint Service	$0.0593	1.51%	$0.0000	0.00%	0.0593	***	1.16%
Lrg Vol Joint Service	$0.0593	1.51%	$0.0000	0.00%	0.0593	***	1.39%

Note: The rate impacts associated with moving the Bison Contract are based on the initial contract length.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Response Comments

Docket No. G007/M-10-1166, G011/M-10-1167, and G011/M-10-1168

Dated this **15th of November**, **2011**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_10-1166_10-1166
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_10-1166_10-1166
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_10-1166_10-1166
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_10-1166_10-1166
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-1166_10-1166
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_10-1166_10-1166
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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_10-1166_10-1166
Michael	Loeffler		Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Paper Service	No	OFF_SL_10-1166_10-1166

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Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_10-1167_10-1167
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_10-1167_10-1167
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_10-1167_10-1167
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-1167_10-1167
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_10-1167_10-1167
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	OFF_SL_10-1167_10-1167
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Michael	Loeffler		Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Paper Service	No	OFF_SL_10-1167_10-1167

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Ann	Seha	seha.ann@dorsey.com	Dorsey & Whitney	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_10-1167_10-1167
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Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_10-1168_10-1168
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_10-1168_10-1168
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