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June 17, 2009

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 Office of Energy Security**
Docket No. G011/M-08-1328

Dear Dr. Haar:

On March 30, 2009, Minnesota Energy Resources Corporation-PNG (MERC-PNG or Company) submitted its *Reply Comments* in response to the Minnesota Office of Energy Security's (OES) March 4, 2009 *Comments* and March 13, 2009 *Supplemental Comments* related to MERC-PNG's Northern Natural Gas (Northern) Purchased Gas Adjustment (PGA) system demand entitlement filing. Based on its review, the OES concludes that a response to MERC-PNG's *Reply Comments* is necessary to establish a complete record in this matter. As such, the OES requests that the Minnesota Public Utilities Commission (Commission) accept these *Response Comments* to MERC-PNG's Northern PGA system *Reply Comments*.

Based on its review of MERC-PNG's *Reply Comments*, the OES recommends that the Commission:

- **approve** MERC-PNG's demand entitlement level, subject to the Commission's decisions in the pending G011/M-07-1405 and G007,011/GR-08-835 dockets, without endorsing its design-day study analysis;
- **require** MERC-PNG to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing;
- **reject** MERC-PNG's proposed cost recovery proposal submitted on November 5, 2008, and its alternate cost recovery proposal, which moves FDD storage cost to the commodity cost recovery portion of the Purchased Gas Adjustment (PGA), presented in its March 30, 2009 *Reply Comments*, instead using the cost recovery proposal developed by the OES;
- **approve** the OES's alternate cost recovery proposal presented in Table R-2;
- **require** MERC-PNG to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-PNG's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

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

Sincerely,

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

AJH/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

RESPONSE COMMENTS OF THE
MINNESOTA OFFICE OF ENERGY SECURITY

DOCKET NO. G011/M-08-1328

I. BACKGROUND

The following rounds of comments have been submitted to the Minnesota Public Utilities Commission (Commission) in Minnesota Energy Resources Corporation-PNG's (MERC-PNG or Company) Northern Natural Gas (Northern) Purchased Gas Adjustment (PGA) system 2008-2009 demand entitlement filing:

- November 1, 2008, MERC-PNG's initial *Petition*;
- November 5, 2008, MERC-PNG's *Supplement*;
- March 4, 2009, Minnesota Office of Energy Security's (OES) *Comments*;
- March 13, 2009, OES's *Supplemental Comments*;
- March 30, 2009, MERC-PNG's *Reply Comments*; and
- June 17, 2009, OES's *Response Comments*.

In its March 30, 2009 *Reply Comments*, MERC-PNG provided additional information and responded to concerns raised by the OES in its March 4, 2009 *Comments*. The OES requested additional information to allow the OES to assess the reasonableness of MERC-PNG's proposal. The OES discusses the Company's responses below.

II. THE OES'S RESPONSE TO MERC-PNG'S MARCH 30, 2009 REPLY COMMENTS

A. MERC-PNG'S EXPLANATION OF ITS DESIGN-DAY RESULTS FOR ITS PGA SYSTEMS AND THE COMPANY'S CALCULATION OF ITS 2007-2008 HEATING SEASON DESIGN-DAY REQUIREMENT USING ITS CURRENT DESIGN-DAY METHODOLOGY

In its March 4, 2009 *Comments*, the OES recommended that MERC-PNG provide an explanation of why its current design-day analysis showed an increase in design-day volumes for its MERC-NMU, MERC-PNG Northern, and MERC-PNG Great Lakes PGA systems and a decrease in design-day volumes for its MERC-PNG Viking PGA system. In addition, the OES also recommended that MERC-PNG re-calculate its design-day requirement for the 2007-2008 heating season using its current design-day methodology.

In its *Reply Comments*, MERC-PNG states that when examining its new design-day methodology it is important to look at the total number of volumes estimated by its regression analysis and not just its firm throughput estimates. In support of this statement, the Company used its current design-day methodology to estimate total system throughput for the 2007-2008 heating season. When using its current methodology for the 2007-2008 heating season, MERC-PNG was able to produce total throughput estimates that are comparable to the same estimates for the 2008-2009 heating season.[1] MERC-PNG then explains that the difference between its old design-day methodology and its current methodology is the Company's treatment of transport and interruptible sales volumes.

However, in an effort to respond to the OES's original questions, MERC-PNG states that the necessary data to estimate previous design-days with its current design-day analysis is unavailable and, as such, the Company is unable to address why there were significant differences in the design-day changes between the PGA systems and to fully compare the design-day estimates for both heating seasons. MERC-PNG produces a design-day estimate for the 2007-2008 heating season using its current design-day methodology; however, given the data issues expressed by the Company, there is not complete support in this docket for the Company's analysis. Ideally, MERC-PNG should initiate new design-day methodology when the Company has the ability to test the new approach against previous results and weather conditions. Given the large changes in design-day estimates, the OES is concerned that firm system performance may be hindered on a peak-day. However, the OES notes, as discussed both in our original *Comments* in this docket and below, that:

1) MERC-PNG's method has merit in terms of providing a more realistic estimate of use by interruptible customers on peak days;
2) MERC-PNG's system performed well in the past year; and

[1] These results are presented in the table at the top of page 2 in MERC-PNG's March 30, 2009 *Reply Comments*.

3) OES agrees with MERC-PNG that it would be helpful to continue to talk about the Company's method, as discussed further below.

Given MERC-PNG's inability to fully compare its design-day estimates against previous heating seasons, the OES recommends that the Commission approve MERC-PNG's Northern PGA system demand entitlement level without endorsing its design-day study analysis. Although the OES believes that MERC-PNG's current design-day methodology has advantages over its previous estimation technique, the OES concludes that it is appropriate to monitor the performance of this method in practice. The OES also requests that the Commission require the Company to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing.

B. MERC-PNG'S PEAK-DAY WEATHER ASSUMPTIONS

Although the OES raised no issues related to MERC-PNG's peak-day weather assumptions, the OES notes that Commission Staff raised concerns about a similar peak-day weather technique in the March 11, 2009 *Briefing Papers* in Docket No. G022/M-07-1142 for Greater Minnesota Gas. MERC-PNG, and its predecessor Aquila Networks-PNG, have had Commission approval to use wind adjusted heating degree days since the early 1990s. As such, MERC-PNG currently uses wind adjusted heating degree days (HDDs) to determine the weather data that it uses in its design-day models. Commission Staff expressed concern that wind chill does not necessarily affect heating load and that the use of adjusted HDDs may produce design-day throughputs that may not be sufficient to meet firm peak-day needs. MERC-PNG offered in *its Reply Comments* to meet with the OES regarding several aspects of MERC-PNG's method. The OES agrees that such a meeting would likely be helpful. The OES notes that Commission Staff may wish to attend this meeting as well.

C. OES'S REQUEST FOR INFORMATION RELATED TO MERC-PNG'S SALES GROWTH RATE

In its initial *Petition*, MERC-PNG stated that it estimated sales growth in its current demand entitlement filing using a different technique than it had in previous demand entitlement filings. The Company did not provide the data necessary to replicate these growth rates and, as such, the OES recommended that MERC-PNG provide these data in its *Reply Comments*. In its *Reply Comments*, MERC-PNG provided this growth rate information, and the assumptions necessary to replicate its growth rates, and, after reviewing these data, the OES believes that MERC-PNG's growth rate estimates are reasonable.

D. MERC-PNG'S TREATMENT OF FARM TAP CUSTOMERS IN ITS DESIGN-DAY CALCULATIONS

MERC-PNG stated in its original *Petition* that it modified its treatment of farm tap customers in its current demand entitlement filing. The Company did not elaborate on this statement; therefore, the OES recommended in its *Comments* that MERC-PNG provide a detailed discussion of how farm tap customers affect design-day calculations in its *Reply Comments*. In response, MERC-PNG explained in greater detail how farm tap customers are accounted for and how these volumes are treated in the design-day calculation. Based on this response, the OES does not have any further concerns related to MERC-PNG's treatment of farm tap customers in its design-day calculations at this time.

E. MERC-PNG SYSTEM PERFORMANCE DURING THE 2008-2009 HEATING SEASON

In its March 4, 2009 *Comments*, the OES noted that MERC-PNG service territory had experienced relatively cold weather conditions during the 2008-2009 heating season. Given these weather events, the OES recommended that the Company provide information related to the performance of its natural gas system during the 2008-2009 heating season. In response, MERC-PNG provided the requested information and included a discussion of its system performance during the most recent heating season. In its *Reply Comments*, the Company states that it does not make nominations based specifically on Northern-NMU or Northern-PNG customers but rather on a full Northern system level. Further, MERC-PNG states that during the most recent heating season it nominated adequate capacity to meet system requirements and that at no point during the heating season did the Company have to fully utilize its firm entitlement capacity.

Based on its review of the Company's discussion and the table at the bottom of Page 5 in its March 30, 2009 *Reply Comments*, it appears that MERC-PNG had sufficient contracted firm capacity to meet system need during the 2008-2009 heating season. As discussed above, the OES intends to continue to review information to ensure that the Company's PGA system would have adequate firm entitlements on a Commission prescribed peak-day.

F. MERC-PNG'S PEAK-DAY SENDOUT ESTIMATE

In its initial *Comments*, the OES noted that MERC-PNG's total entitlement per customer forecast is smaller than the all-time peak-day sendout per customer, which indicates that the Company's design-day proposal may not ensure system reliability on a peak-day. Therefore, the OES recommended that MERC-PNG provide, in its *Reply Comments*, a full discussion of why its total entitlement per customer estimate is sufficient to ensure system reliability on a Commission prescribed peak-day of -25°F for 24 hours. In response, MERC-PNG states that it has experienced declines in use per customer since the all-time peak-day sendout per customer of 1.5175 Mcf/day occurred and, as such, it does not believe this result will occur again.

The Company further explains that there are three options that may address the OES's concern. The first is that, for next heating season, MERC-PNG has contracted for an additional 4,227 Mcf/day of winter capacity with its TFX5 (November to March) service. This service contract has provisions for additional capacity every two years to account for customer growth. The additional capacity that MERC-PNG will acquire next heating season will account for a significant amount of the difference between the Company's current total entitlement per customer estimate and its all-time peak-day sendout per customer result. MERC-PNG's second option involves its tariffs as they relate to its transportation customers. If MERC-PNG believes that operational integrity will be tested on a given day, it has the ability to require these customers to take only their Maximum Daily Quantity, which MERC-PNG states will provide additional firm volumes. The third, and final, option that MERC-PNG mentions is its ability to purchase delivered service at MERC-PNG citygates. Although these three options do not fully account for the difference in peak-day sendout per customer estimates, the OES is confident that the Company is committed to firm system integrity and is not intentionally carrying inadequate firm entitlements. Finally, the OES notes that MERC-PNG's change in its estimate of peak use by interruptible customers implies that MERC-PNG may be able to free up more capacity on a peak day by interrupting these customers. While there is never a guarantee that interruptible customers will be on the system at any given point in time and thus available to be interrupted, MERC-PNG certainly should use interruptions of these customers to ensure that service to firm customers is reliable.

G. DISCREPANCIES IN CONTRACT ENTITLEMENT LEVELS REPORTED BY MERC-PNG IN ITS PETITION

While reviewing MERC-PNG's *Petition*, the OES observed that there were some discrepancies in MERC-PNG's proposed changes to its design-day capacity portfolio, in particular its TFX12, TFX5, and TFX7 contracts. Given these issues, the OES withheld any recommendation on MERC-PNG's total peak-day entitlement level proposal until the Company explained all discrepancies in its filing and provided information on which entitlement levels were appropriate to use in the OES's analysis.

In its *Reply Comments*, MERC-PNG noted that the OES's observations about 10,837 Mcf/day of capacity, discussed by the OES in Part C of its March 4, 2009 *Comments*, were correct and these volumes related to MERC-PNG's TFX12 and TFX5 contracts and not its TFX7 contract as stated in the Company's *Petition*. The Company further states that it identified these volumes as TFX7 as a means of designating how many months it receives a discount rate on these volumes. Based on MERC-PNG's *Reply Comments*, the OES no longer has concerns about the discrepancies identified in its *Comments* and, after taking into account the OES's concerns in Section III, Subsection A, the OES recommends that the Commission approve MERC-PNG's demand entitlement level, as identified in the OES's March 4, 2009 *Comments*, Attachment 2, without endorsing its design-day study analysis, and subject to the Commission's decisions in the pending G011/M-07-1405 and G007,011/GR-08-835 dockets.

H. MERC-PNG'S TREATMENT OF FDD STORAGE IN ITS COST RECOVERY PROPOSAL

In its March 4, 2009 *Comments*, the OES noted that MERC-PNG had not moved the cost recovery of its FDD Storage contracts to the commodity cost recovery portion of the monthly PGA, rather than the demand cost recovery portion, as it had proposed in its March 7, 2008 *Supplemental Comments* in Docket No. G007/M-07-1405. In response to the OES's concerns, MERC-PNG provided a discussion of why it included FDD Storage costs in the demand cost recovery portion of the PGA. In this discussion, MERC-PNG stated that it did not include FDD Storage costs in the commodity cost recovery portion of the PGA, as it had proposed in the previous demand entitlement filing, since the Commission has not issued an *Order* in Docket No. G007/M-07-1402. However, MERC-PNG did file on March 30, 2009 with the Commission revised Attachments 4, page 1 of 3, and 11 from its original *Petition* that shift these FDD Storage costs to the commodity recovery portion of the PGA.[2]

Based on its review of MERC-PNG's revised Attachments 4 and 11, the OES is unable to replicate MERC-PNG's total demand cost recovery figure ($0.9122 per Mcf). Using the annual firm sales figure reported in MERC-PNG's original Attachment 4, page 2 of 3, (18,915,740 Mcf)[3] and the same volumes for each demand contract, as clarified in Section III, Subsection G, the OES estimates a total demand cost recovery figure of $0.9050 (OES Attachment R-2). The OES discusses this difference and its overall cost recovery proposal in Section IV below.

I. MERC-PNG'S PGA COST RECOVERY

Through its analysis of MERC-PNG's initial *Petition*, the OES noted that the revised spreadsheets filed by MERC-PNG on November 5, 2008 did not include evidence substantiating the demand cost figures reported by the Company. Based on the change in demand costs included in the revised spreadsheets and the Company's cost recovery proposal for its storage-related contracts, the OES withheld recommendation on MERC-PNG's cost recovery proposal until the Company could provide sufficient evidence supporting its cost recovery proposal.

In response to this concern, the Company states in its *Reply Comments* that the demand costs reported in its original Attachment 4, page 1 of 3, and Attachment 1 were placeholders and did not represent calculated demand costs, and the cost estimates provided in its November 5, 2008 are in fact the calculated demand costs. However, based on its review of the information provided in its *Reply Comments*, the OES still cannot find supporting information, or calculations, that substantiate the cost calculations provided by MERC-PNG in its November 5, 2008 filing. Given this fact, and the OES's difficulty in reconciling the Company's cost proposal

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[2] Please note that MERC-PNG only filed a revised Attachment 4, page 1 of 3. The Company did not include pages 2 and 3 of Attachment 4 in its filing.
[3] This figure represents MERC-PNG's Northern PGA System Annual General Service volumes in its 2000 rate case (Docket No. G007,011/GR-00-951).

discussed in Section II, Subsection H above, the OES recommends that the Commission reject MERC-PNG's proposed cost recovery proposal submitted on November 5, 2008, and its alternate cost recovery proposal, which moves FDD storage cost to the commodity cost recovery portion of the PGA, presented in its March 30, 2009 *Reply Comments* since MERC-PNG has been unable to substantiate its cost calculations. Instead, the OES proposes a cost recovery proposal, based on the Company's filed entitlement numbers, in Section III below.

III. THE OES'S COST RECOVERY PROPOSAL

For comparative purposes, the OES includes in Table R-1 below the Company's cost recovery proposal submitted in its November 5, 2008 *Supplement*. When analyzing the effects associated with its demand entitlement changes, MERC-PNG calculates the following changes effective November 1, 2008 and proposes to begin recovering the costs associated with the requested demand entitlement changes in the monthly PGA effective November 1, 2008. These changes result in the following bill impacts:

Table R-1
MERC-PNG's November 5, 2008 PGA Cost Recovery Proposal
Monthly Rate Impact Compared to October 2008 PGA

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)	Total Change (Percent)	Effect on Annual Bill
General Service	$0.7199	12.04	$(0.0020)	(0.18)	$0.7179	8.26	$91.43
Small Vol. Interruptible	$0.7199	12.04	$0.0000	0.00	$0.7199	9.97	$3,562.07
Large Vol. Interruptible	$0.7199	12.04	$0.0000	0.00	$0.7199	11.36	$10,684.04
Small Vol. Joint Firm	$0.7199	12.04	$0.0000	0.00	$0.7199	9.97	$3,562.07
Large Vol. Joint Firm	$0.7199	12.04	$0.0000	0.00	$0.7199	11.36	$10,684.04

As shown above, and in MERC-PNG's Attachment 11 filed on November 5, 2008, the Company's proposed entitlement levels result in the following estimated annual bill impacts:

- an increase of approximately $91.43 per year, or 8.26 percent, for an average General Service customer who consumes 127 Mcf annually;
- an increase of approximately $3,562.07 per year, or 9.97 percent, for an average Small Volume Interruptible customer who consumes 4,948 Mcf annually;
- an increase of approximately $10,684.04 per year, or 11.36 percent, for an average Large Volume Interruptible customer who consumes 14,841 Mcf annually; and
- an increase of approximately $3,562.07 per year, or 9.97 percent, for an average Small Volume Firm customer who consumes 4,948 Mcf annually; and

- an increase of approximately $10,684.04 per year, or 11.36 percent, for an average Large Volume Firm customer who consumes 14,841 Mcf annually.

Based on the concerns that the OES discusses in Section II, Subsections H and I above, the OES proposes a cost recovery proposal using the same demand entitlement levels, and changes, proposed by MERC-PNG in its November 1, 2008 *Petition*, and clarified by the Company in its *Reply Comments*, and discussed in the OES's March 4, 2009 *Comments*. The OES's cost recovery proposal is different from that presented in MERC-PNG's November 5, 2008 filing due to: 1) the OES's treatment of FDD storage costs and 2) how the OES determines bill impacts. First, unlike the Company, the OES holds the weighted average cost of gas constant, so as to isolate the increases in total gas costs associated solely with the demand cost of gas. Second, while the OES understands why MERC-PNG calculated FDD Storage costs in the manner used in the November 5, 2008 filing, the OES expects that FDD Storage costs are likely to be recovered from all customers. As a result, the OES includes FDD Storage related costs in the commodity cost recovery portion of the PGA, as proposed by MERC-PNG in its March 7, 2008 *Supplemental Comments* in Docket No. G011/M-07-1405. The OES's bill impacts are presented in Table R-2 below:

Table R-2
OES's Modified PGA Cost Recovery Proposal
Monthly Rate Impact Compared to October 2008 PGA

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)	Total Change (Percent)	Effect on Annual Bill
General Service	$(0.0274)	(0.44)	$0.0210	2.38	$(0.0064)	(0.07)	$(0.81)
Small Vol. Interruptible	$(0.0274)	(0.44)	$0.0000	0.00	$(0.0274)	(0.37)	$(135.58)
Large Vol. Interruptible	$(0.0274)	(0.44)	$0.0000	0.00	$(0.1444)	(2.21)	$(2,143.04)
Small Vol. Joint Firm	$(0.0274)	(0.44)	$(0.1909)	(1.89)	$(0.0274)	(0.37)	$(0.22)
Large Vol. Joint Firm	$(0.0274)	(0.44)	$(0.1909)	(1.89)	$(0.0274)	(0.42)	$(0.22)

Note: The changes in commodity costs presented in Table R-2 are the result of a decrease in MERC-PNG's FDD Storage levels and cost contracts.

As shown above, and in OES Attachment R-1, the OES's demand entitlement analysis results in the following estimated annual bill impacts:

- a decrease of approximately $0.81 per year, or 0.07 percent, for an average General Service customer who consumes 127 Mcf annually;
- a decrease of approximately $135.58 per year, or 0.37 percent, for an average Small Volume Interruptible customer who consumes 4,948 Mcf annually;

- a decrease of approximately $2,143.04 per year, or 2.21 percent, for an average Large Volume Interruptible customer who consumes 14,841 Mcf annually;
- a decrease of approximately $0.22 per year, or 0.37 percent, for an average Small Volume Joint Firm customer who consumes 4,948 Mcf annually; and
- a decrease of approximately $0.22 per year, or 0.42 percent, for an average Large Volume Joint Firm customer who consumes 14,841 Mcf annually.

Given the concerns expressed by the OES as they relate to MERC-PNG's cost recovery proposal, the OES recommends that the Commission approve its alternate cost recovery proposal presented in Table R-2. Once the Commission decides the issues in Docket No. G011/M-07-1405, the OES recommends that the Commission require MERC-PNG to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-PNG's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

IV. OES RECOMMENDATIONS AND CONCLUSIONS

Based on its review of MERC-PNG's *Reply Comments*, the OES recommends that the Commission:

- **approve** MERC-PNG's demand entitlement level, subject to the Commission's decisions in the pending G011/M-07-1405 and G007,011/GR-08-835 dockets, without endorsing its design-day study analysis;
- **require** MERC-PNG to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing;
- **reject** MERC-PNG's proposed cost recovery proposal submitted on November 5, 2008, and its alternate cost recovery proposal, which moves FDD storage cost to the commodity cost recovery portion of the Purchased Gas Adjustment (PGA), presented in its March 30, 2009 *Reply Comments*, instead using the cost recovery proposal developed by the OES;
- **approve** the OES's alternate cost recovery proposal presented in Table R-2;
- **require** MERC-PNG to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-PNG's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

/jl

OES Attachment R-1

Rate Impact of MERC-PNG's Northern PGA System Proposed Demand Entitlement Changes as Modified by the OES

1) General Service: Avg. Annual Use: 127 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-07-1405	Most Recent PGA Oct 1/08	Oct 1/08 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	$6.1660	$7.1402	$6.1660	$6.1386	-0.44%	-14.03%	-0.44%	($0.0274)
Demand Rate	$0.8840	$1.1741	$0.8840	$0.9050	2.38%	-22.92%	2.38%	$0.0210
Margin	$1.7870	$1.1771	$1.7870	$1.7870	0.00%	51.81%	0.00%	$0.0000
Total Recovery	$8.8370	$9.4914	$8.8370	$8.8306	-0.07%	-6.96%	-0.07%	($0.0064)
Avg. Annual Bill*	$1,122.30	$1,205.41	$1,122.30	$1,121.49	-0.07%	-6.96%	-0.07%	($0.8128)
Effect of proposed commodity change on average annual bills:								($3.4798)
Effect of proposed demand change on average annual bills:								$2.6670

2) Small Volume Interruptible: Avg. Annual Use: 4,948 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-07-1405	Most Recent PGA Oct 1/08	Oct 1/08 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	$6.1660	$7.1402	$6.1660	$6.1386	-0.44%	-14.03%	-0.44%	($0.0274)
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$1.2800	$0.9000	$1.2800	$1.2800	0.00%	42.22%	0.00%	$0.0000
Total Recovery	$7.4460	$8.0402	$7.4460	$7.4186	-0.37%	-7.73%	-0.37%	($0.0274)
Avg. Annual Bill*	$36,842.81	$39,782.91	$36,842.81	$36,707.23	-0.37%	-7.73%	-0.37%	($135.5752)
Effect of proposed commodity change on average annual bills:								($135.5752)
Effect of proposed demand change on average annual bills:								$0.0000

3) Large Volume Interruptible: Avg. Annual Use: 14,841 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-07-1405	Most Recent PGA Oct 1/08	Oct 1/08 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	$6.1660	$7.1402	$6.1660	$6.1386	-0.44%	-14.03%	-0.44%	($0.0274)
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.3770	$0.2600	$0.3770	$0.2600	-31.03%	0.00%	-31.03%	($0.1170)
Total Recovery	$6.5430	$7.4002	$6.5430	$6.3986	-2.21%	-13.53%	-2.21%	($0.1444)
Avg. Annual Bill*	$97,104.66	$109,826.37	$97,104.66	$94,961.62	-2.21%	-13.53%	-2.21%	($2,143.0404)
Effect of proposed commodity change on average annual bills:								($406.6434)
Effect of proposed demand change on average annual bills:								$0.0000

4) Small Volume Firm: Avg. Annual Use: 1 Mcf (MERC-PNG currently has no customers in this class.)
Avg. Annual CD Volumes: 1 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-07-1405	Most Recent PGA Oct 1/08	Oct 1/08 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	$6.1660	$7.1402	$6.1660	$6.1386	-0.44%	-14.03%	-0.44%	($0.0274)
Demand Rate	$10.0988	$12.4583	$10.0988	$9.9079	-1.89%	-20.47%	-1.89%	($0.1909)
Comm. Margin	$1.2800	$0.9000	$1.2800	$1.2800	0.00%	42.22%	0.00%	$0.0000
SV Dem. Margin	$1.8000	$1.5000	$1.8000	$1.8000	0.00%	20.00%	0.00%	$0.0000
Total Commodity Cost	$7.4460	$8.0402	$7.4460	$7.4186	-0.37%	-7.73%	-0.37%	($0.0274)
Total Demand Cost	$11.8988	$13.9583	$11.8988	$11.7079	-1.60%	-16.12%	-1.60%	($0.1909)
Avg. Annual Bill*	$19.34	$22.00	$19.34	$19.13	-1.13%	-13.06%	-1.13%	($0.2183)
Effect of proposed commodity change on average annual bills:								($0.0274)
Effect of proposed demand change on average annual bills:								($0.1909)

5) Large Volume Firm: Avg. Annual Use: 1 Mcf (MERC-PNG currently has no customers in this class.)
Avg. Annual CD Units: 1 Mcf

Recovery	Last Base Cost of Ga G011/MR-08 836	Last Demand Change M-07-1405	Most Recent PGA Oct 1/08	Oct 1/08 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	$7.1402	$6.1660	$6.1386	280.38%	-14.03%	-0.44%	($0.0274)
Demand Rate	$10.0988	$12.4583	$10.0988	$9.9079	-1.89%	-20.47%	-1.89%	($0.1909)
Comm. Margin	$0.3770	$0.2600	$0.3770	$0.3770	0.00%	45.00%	0.00%	$0.0000
LV Dem. Margin	$1.5000	$1.2000	$1.5000	$1.5000	0.00%	25.00%	0.00%	$0.0000
Total Commodity Cost	$1.9908	$7.4002	$6.5430	$6.5156	227.29%	-11.95%	-0.42%	($0.0274)
Total Demand Cost	$11.5988	$13.6583	$11.5988	$11.4079	-1.65%	-16.48%	-1.65%	($0.1909)
Avg. Annual Bill*	$13.59	$21.06	$18.14	$17.92	31.89%	-14.89%	-1.20%	($0.2183)
Effect of proposed commodity change on average annual bills:								($0.0274)
Effect of proposed demand change on average annual bills:								($0.1909)

* 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	($0.0274)	-0.44%	$0.0210	2.38%	(0.0064)		-0.07%
Sm Vol Inter. Service	($0.0274)	-0.44%	$0.0000	0.00%	(0.0274)		-0.37%
Lrg Vol Inter. Service	($0.0274)	-0.44%	$0.0000	0.00%	(0.1444)		-2.21%
Sm Vol Joint Service	($0.0274)	-0.44%	($0.1909)	-1.89%	(0.0274)	***	-0.37%
Lrg Vol Joint Service	($0.0274)	-0.44%	($0.1909)	-1.89%	(0.0274)	***	-0.42%

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

Note: The commodity figure with updated demand entitlement levels of $6.1386 includes $0.1594 in costs related to storage and producer demand per the Company's supplemental comments filed on March 7, 2008.

Prepared by the Minnesota Office of Energy Security

OES Attachment R-2

OES's Modified MERC-PNG Northern PGA System Rate Impact Analysis

I. Minnesota Energy Resources Corporation's Cost of Gas

	Summer	Winter	Weighted Annual
TF-12B	7.5776	15.1530	10.7340
TF-12V	9.0926	7.6050	8.4728
TF-5	0.0000	4.5600	4.5600
FTX	9.6288	5.6830	7.9847
Field TF	0.0000	0.0000	0.0000
Commodity			5.9792

II. Annual Firm Sales – Rate Case 2000 General Service (CCF) 189,157,400

III. Minnesota Energy Resources Corporation's Cost of Gas

A. GS, SVI, LVI	MCF	Months	Rate/MCF	Total	Rate/CCF
TF-12-B	25,469	12	7.5776	$2,315,927	$0.01224
TF-12-V	32,690	12	9.0926	$3,566,845	$0.01886
TF-5	26,064	5	15.1530	$1,974,739	$0.01044
TF-12B (Discount Winter)	4,437	5	7.6050	$168,717	$0.00089
TF-5 (Discount Winter)	763	5	7.6050	$29,013	$0.00015
TFX-12	9,724	12	9.6288	$1,123,565	$0.00594
TFX-5	6,000	5	4.5600	$136,800	$0.00072
TFX Apr	2,000	1	5.6830	$11,366	$0.00006
TFX Oct	2,000	1	5.6830	$11,366	$0.00006
TFX-5 (Max)	46,558	5	15.1530	$3,527,467	$0.01865
TFX-5 (Discount)	2,196	5	13.8736	$152,332	$0.00081
TFX-5 (Discount)	1,800	5	7.6050	$68,445	$0.00036
TFX-12 (Discount)	414	12	4.8667	$24,178	$0.00013
TFX-12 (Discount)	8,271	12	5.4570	$541,618	$0.00286
TFX-7	10,837	7	2.2204	$168,437	$0.00089
TFX-5 (Discount)	122	5	4.8667	$2,969	$0.00002
TFX-5 (Discount)	2,445	5	5.4570	$66,712	$0.00035
TFX-5 (Discount)	31,009	5	15.1475	$2,348,544	$0.01242
SMS Charge	20,537	12	2.1800	$537,248	$0.00284
Option	26,323	3	4.3463	$343,223	$0.00181
Windom	0	12	0	$0	$0.00000
Exchange	0		2.0035	$0	$0.00000
Total Demand Cost				**$17,119,511**	**$0.09050**
FDD: Res Fee	68,309	12	1.7140	$1,404,980	$0.00743
FDD: Capacity	787,676	5	0.3567	$1,404,820	$0.00743
FDD-Reservation	3,141	12	1.714	$64,604	$0.00034
FDD-Storage Cycle	36,221	5	0.3567	$64,600	$0.00034
FDD-Reservation	5,026	12	3.3157	$199,976	$0.00106
FDD-Storage Cycle	57,953	5	0.6901	$199,967	$0.00106
Total Storage				**$3,338,947**	**$0.01765**
GS Rate Case 2000 Volume in CCF				189,157,400	
GS-1 Demand Base Cost of Gas/Ccf					**$0.09050**

GS-1 Commodity Base Cost of Gas/Ccf	189,157,400	$0.59792	$113,100,993	$0.59792
FDD Storage Costs			$3,338,947	$0.01765
Call Option Premium			$0	$0.00000
Commodity Assigned 636 Costs From Schedule C			$0	$0.00000
All Classes Commodity			$116,439,940	$0.61557
All Classes Rate Case 2000 Volume in Ccf			189,157,400	
Commodity Cost of Gas/CCF				**$0.61557**
Total Cost of Gas/CCF				**$0.70608**

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

Total Base Commodity Cost of Gas/CCF	$0.61557
Firm Transportation Base Cost of Gas/CCF	$1.07340

C. Joint Rate Demand Calculation (See MERC's Sch. C) $9.9079 /MCF $0.99079

Costs Assigned In Commodity:

Canadian Contracts	Units	Cost/Unit	Day/Mo.	Cost	$/MCF
Upstream					
NBPL (West Coast)	0	$0.000	12	$0	$0.00000
FT0011 (GLGT-Nexen)	0	$10.278	7	$0	$0.00000
Great Lakes	0	$3.458	12	$0	$0.00000
					$0.00000
Storage					
FDD Withdrawal	0	$0.0149		$0	$0.00000
FDD Injection	0	$0.0149		$0	$0.00000
FDD Withdrawal	0	$0.0149		$0	$0.00000
FDD Injection	0	$0.0149		$0	$0.00000
					$0.00000
Producer Demand Payments				$0	$0.00000
Total Commodity Costs				$0	$0.00000

Costs Assigned In Joint Rate

	Units	Months	Rate	Total	Rate/Mcf
TF-12-B	25,469	12	$7.5776	$2,315,927	$1.32667
TF-12-V	32,690	12	$9.0926	$3,566,845	$2.04325
TF5-(12V)	26,064	5	$15.1530	$1,974,739	$1.13122
TF-12B	4,437	12	$6.4838	$345,223	$0.19776
TF5 (Discount-Winter)	763	5	$7.6050	$29,013	$0.01662
TFX5	6,000	5	$4.5600	$136,800	$0.07837
TFX12	9,724	12	$9.6288	$1,123,565	$0.64363
TFX Oct	2,000	1	$5.6830	$11,366	$0.00651
TFX5	2,000	1	$5.6830	$11,366	$0.00651
TFX5	46,558	5	$15.1530	$3,527,467	$2.02069
TFX5 (Discount)	2,196	5	$13.8736	$152,332	$0.08726
TFX5 (Discount)	1,800	5	$7.6050	$68,445	$0.03921
TFX12 (Discount)	414	12	$4.8667	$24,178	$0.01385
TFX12 (Discount)	8,271	12	$5.4570	$541,618	$0.31026
TFX7 (Discount)	10,837	7	$2.2204	$168,437	$0.09649
TFX5 (Discount)	122	5	$4.8667	$2,969	$0.00170
TFX5 (Discount)	2,445	5	$5.4570	$66,712	$0.03822
TFX5 (Discount)	31,009	5	$15.1475	$2,348,544	$1.34535
SMS Charge	20,537	12	$2.1800	$537,248	$0.30776
LS Power	26,323	3	$4.3463	$343,223	$0.19661
Windom	2,500	12	$0.0000	$0	$0.00000
Exchange	0	1	$2.0035	$0	$0.00000
FDD-Reservation	3,141	12	$1.7140	$64,604	$0.03701
FDD-Storage Cycle	36,221	5	$0.3567	$64,600	$0.03701
FDD-Reservation	5,026	12	$3.3157	$199,976	$0.11456
FDD-Storage Cycle	57,953	5	$0.6901	$199,967	$0.11455
FDD-Reservation	68,309	12	$1.7140	$1,404,980	$0.80484
FDD-Storage Cycle	787,676	5	$0.3567	$1,404,820	$0.80474
Total Demand Cost		Total		$17,296,018	
		Annualized Entitlement Mcf		1,745,673	
		Demand Component		$9.9079	**$9.9079**

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, 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 Office of Energy Security
Response Comments

Docket No. G011/M-08-1328

Dated this **17th** day of **June**, **2009**

/s/Sharon Ferguson

G011/M-08-1328

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