MICHAEL J. AHERN
(612) 340-2881
FAX (612) 340-2643
ahern.michael@dorsey.com

August 12, 2009

VIA ELECTRONIC FILING

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

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System
Docket No. G011/M-08-1328

Dear Dr. Haar:

Enclosed please find the Response Comments of Minnesota Energy Resources Corporation ("MERC" or "Company") in the above-referenced docket. MERC submitted its initial Petition to the Commission on November 3, 2008 and filed revised spreadsheets shortly thereafter on November 5, 2008. The OES issued its initial Comments on March 4, 2009 and Supplemental Comments on March 13, 2009, and MERC filed its Reply Comments on March 30, 2009. On June 17, 2009, the OES issued Response Comments that noted areas in which the OES had continuing questions or concerns regarding the Company's proposal. The Company requests that the Commission accept these Response Comments, which address the issues raised by the OES in their June 17, 2009 Response Comments.

Thank you for your attention to this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

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

Docket No. G011/M-08-1328

RESPONSE COMMENTS OF
MINNESOTA ENERGY RESOURCES CORPORATION

Minnesota Energy Resources Corporation-PNG ("MERC" or "Company") submits to the Minnesota Public Utilities Commission ("Commission") these Response Comments in response to the June 17, 2009 Response Comments of the Minnesota Office of Energy Security ("OES") in the above referenced matter.

MERC submitted its initial Petition to the Commission on November 3, 2008 and filed revised spreadsheets shortly thereafter on November 5, 2008. The OES issued its initial Comments on March 4, 2009 and Supplemental Comments on March 13, 2009, and MERC filed its Reply Comments on March 30, 2009. On June 17, 2009, the OES issued Response Comments that noted areas in which the OES had continuing questions or concerns regarding the Company's proposal. The Company requests that the Commission accept these Response Comments, which address the issues raised by the OES in their June 17, 2009 Response Comments.

A. **Design-Day Study**

The OES recommended that the Commission approve MERC-PNG's NNG system demand entitlement level without endorsing its design-day study analysis, noting 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
3) OES agrees with MERC-PNG that it would be helpful to continue to talk about the Company's method.

The OES stated that although it believes that MERC-PNG's current design-day methodology has advantages over its previous estimation technique, the OES concluded that there is not complete support for the Company's analysis in this docket and that it is appropriate to monitor the performance of the Company's method in practice. The OES also requested 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.

Response

As the OES stated, MERC-PNG's system performed well in the past year, and MERC-PNG had sufficient firm capacity to meet its need during the 2008-2009 heating season. MERC also agrees with the OES that its new methodology provides a more realistic estimate of use by interruptible customers on peak days. In the Company's rate case in Docket No. G007,011/GR-08-835, the Commission approved MERC's proposal that all interruptible and transportation customers be required to install telemetry equipment. The use of telemetry equipment by all interruptible and transportation customers will provide the daily data to make the design day calculation more realistic. In particular, telemetry will provide MERC with daily interruptible and transportation volumes that can be deducted from the total daily throughput to ascertain actual firm consumption.

MERC-PNG is willing to discuss making reasonable changes to its design day forecasting process, including preparing and providing appropriate documentation related to the "estimative power of its design day study" as requested by the OES. MERC-PNG requests clarification of the specific metrics or measures that would best describe "estimative power" including the preferred method of calculation and preferred format for the results (e.g. memo, table, graph, set of graphs). To that end, MERC agrees that it would be helpful to meet with the OES to further discuss the Company's design-day methodology.

B. Peak-Day Weather Assumptions

The OES noted that although it raised no issues related to MERC-PNG's peak-day weather assumptions, Commission Staff raised concerns about a similar peak-day weather technique in the March 11, 2009 Briefing Papers in Docket G022/M-07-1142 for Greater Minnesota Gas. The OES pointed out that MERC-PNG, and its predecessor Aquila Networks-PNG, have had Commission approval to use wind adjusted heating degree days since the early 1990s and that MERC-PNG currently uses wind adjusted HDDs to determine the weather data it uses in its design-day models. In Docket No. G022/M-07-1142, 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. The OES suggested that it would be useful to discuss MERC's design-day methodology in a meeting with MERC and that Commission Staff may wish to attend as well.

Response

The OES noted that MERC-PNG, and its predecessor Aquila Networks-PNG, have had Commission approval to use wind adjusted HDDs since the early 1990s. When completing regression analysis, it has been MERC's experience that there is a stronger correlation between Adjusted HDD (wind adjusted) and consumption compared to Unadjusted HDD (65 minus the average of the high/low temperature) and consumption. The stronger correlation leads MERC to believe that HDD adjusted for wind is a better indicator of customer consumption. MERC is willing to further discuss this issue in a meeting with the OES and Commission Staff to discuss MERC's design-day methodology.

C. Treatment of FDD Storage Costs

In response to concerns raised in the OES's initial Comments, MERC filed revised Attachments 4, page 1 of 3, and 11 that shifted FDD storage costs to the commodity recovery portion of the PGA. Based on its review of MERC's revised Attachments 4 and 11, the OES stated that it was unable to replicate the Company's total demand cost recovery figure ($0.9122 per Mcf). Using the firm sales figure reported in MERC-PNG's original Attachment 4, page 2 of 3 (18,915,740 Mcf), and the same volumes for each demand contract as clarified in MERC's Reply Comments, the OES estimated a total demand cost recovery figure of $0.9050.

Response

When MERC filed its Reply Comments on March 30, 2009, the Company provided revised Attachment 4, page 1 of 3, and Attachment 11 that showed the effects of moving the FDD storage costs to the commodity cost recovery portion of the monthly PGA in the event the Commission approves the shift of storage costs from the demand rate to the commodity rate.

MERC, however, failed to provide a revised versions of Attachment 4, page 2 of 3 and page 3 of 3 in support of shifting of FDD costs from demand to commodity. A complete revised Attachment 4, pages 1 -3, showing the effects of moving the FDD storage costs from demand to commodity and the supporting cost details, is provided as Exhibit 1 to these Response Comments. MERC regrets any inconvenience the failure to include this information may have caused.

The revised versions of Attachment 4, pages 2 and 3 display the information and calculations substantiating MERC's revised total demand cost recovery figure of $0.9122 per Mcf. This factor is calculated by using the firm sales figure reported in MERC-PNG's resubmitted Attachment 4, page 2 of 3 (20,942,963 Mcf) included in Exhibit 2 to these Response Comments and discussed in more detail in section D, below.

D. <u>PGA Cost Recovery</u>

In its initial Comments, the OES had noted that the demand cost estimates included in MERC's initial Petition filed November 3, 2008 and the Company's revised spreadsheets filed November 5, 2008 were not the same. In Reply Comments, the Company noted that Attachments 4 and 11 of the initial filing included estimated demand costs that had been used as placeholders in preparation of the attachments pending calculation of the actual demand costs. Soon after filing, MERC realized that it had failed to replace the estimated costs with the actual demand costs and that Attachments 4 and 11 were not accurate. MERC therefore filed revised attachments that included the actual demand costs on November 5, 2008. Based on its review of the information provided in the Reply Comments, however, the OES stated that it could not 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 discussed in C, above, the OES recommended that the Commission reject MERC-PNG's 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. Instead, the OES recommended that the Commission adopt the OES's cost recovery proposal and require MERC-PNG to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC's cost recovery proposal submitted on November 5, 2008 and charged in rates through the PGA since November 1, 2008.

Response

As noted in MERC's Reply Comments, Attachments 4 and 11 of the Company's initial Petition included estimated demand costs that had been used as placeholders in preparation of the attachments pending calculation of the actual demand costs. MERC realized its error shortly after filing and filed revised Attachment 4, page 1 of 3, and Attachment 11 on November 5, 2008, that replaced the estimated costs with the actual demand costs. MERC recently has realized that when it submitted the revised attachments on November 5, 2008, the Company failed to submit revised Attachment 4, pages 2 of 3 and 3 of 3, that included actual (rather than estimated) costs. Attached as Exhibit 2 is a complete Attachment 4, pages 1-3, that replaces the estimated demand costs with actual demand costs in all three pages of the attachment.[1]

The demand entitlement and sales values contained in the resubmitted Attachment 4, page 2 of 3 in Exhibit 2 were used in the calculation of the rate factors contained in the initial

[1] The only difference between Exhibit 1 and Exhibit 2 to these Response Comments is that Exhibit 1 shows the effect of shifting the FDD storage costs from the demand portion of rates to commodity.

November 3, 2008 filing by MERC as well as the Reply Comments filed on March 30, 2009. Additionally, the demand entitlement and sales values listed on the resubmitted Attachment 4, page 2 of 3, were used in the calculation of the November 1, 2008 monthly MERC-PNG-NNG PGA filings and have been used in subsequent monthly PGA filings. The resubmitted Attachment 4, page 2 of 3, provides supporting information and calculations that substantiate the cost recovery calculations proposed by MERC in its November 3, 2008 filing and in the calculations, requested by the OES to be filed in MERC's Reply Comments, which demonstrated shifting the recovery of FDD costs from demand to commodity (see Exhibit 1).

MERC requests that the OES re-evaluate MERC's proposed cost recovery proposal submitted on November 3, 2008 and the cost recovery calculations provided in MERC's March 30, 2009 Reply Comments using the resubmitted version of Attachment 4 included in Exhibit 2 and the revised version of Attachment 4 included in Exhibit 1, respectively.

At this point in time the Commission has not approved the shifting of FDD costs from the demand recovery to the commodity recovery portion of the PGA. If the Commission does approve that shift, MERC believes it would be appropriate to work with the OES and Commission Staff to develop a process which will credit GS customers for the collection of FDD costs recovered via the demand portion of the PGA and recover those same FDD costs from all customer groups via the commodity portion of the PGA.

DATED this 12th day of August, 2009.

Respectfully submitted,

DORSEY & WHITNEY LLP

/s/ Michael J. Ahern _
Michael J. Ahern
50 South Sixth Street
Minneapolis, MN 55402
(612) 340-2600

Attorney for MERC

`

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2008
NNG

All costs in $/MMBtu	Last Rate Case G011/ MR03-1372	Last Demand Change G011- M-06- Oct .06	Last Demand Change G011- M-07- Oct. 07	Most Recent PGA Oct. 2008	Current Proposal Effective Nov.1,2008	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service: Avg. Annual Use:		**127**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.8586	$4.0713	($0.0096)	14.71%	$0.8794
Demand Cost	$0.7886	$1.1097	$1.1741	$1.0903	$0.9122	$0.1236	($0.2619)	-16.33%	($0.1781)
Commodity Margin	$1.2628	$1.1771	$1.1771	$1.6263	$1.6263	$0.3635	$0.4492	0.00%	$0.0000
Total Cost of Gas	$4.8387	$7.4702	$9.2194	$8.6958	$9.3971	$4.5584	$0.1777	8.06%	$0.7013
Avg Annual Cost	$614.51	$948.72	$1,170.86	$1,104.37	$1,193.43	$578.92	$22.57	8.06%	$89.0651
Effect of proposed commodity change on average annual bills:									$111.68
Effect of proposed demand change on average annual bills:									($22.62)
2) Small Vol. Interruptible: Avg. Annual Use:		**4,948**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.8586	$4.0713	($0.0096)	14.71%	$0.8794
Demand Cost	$0.0000								
Commodity Margin	$0.9000	$0.9000	$0.9000	$1.2434	$1.2434	$0.3434	$0.3434	0.00%	$0.0000
Total Cost of Gas	$3.6873	$6.0834	$7.7682	$7.2226	$8.1020	$4.4147	$0.3338	12.18%	$0.8794
Avg Annual Cost	$18,244.76	$30,100.66	$38,437.05	$35,737.42	$40,088.70	$21,843.94	$1,651.64	12.18%	$4,351.2712
Effect of proposed commodity change on average annual bills:									$4,351.27
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**14,841**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.8586	$4.0713	($0.0096)	14.71%	$0.8794
Demand Cost									
Commodity Margin	$0.2600	$0.2600	$0.2600	$0.3592	$0.3592	$0.0992	$0.0992	0.00%	$0.0000
Total Cost of Gas	$3.0473	$5.4434	$7.1282	$6.3384	$7.2178	$4.1705	$0.0896	13.87%	$0.8794
Avg Annual Cost	$45,224.98	$80,785.50	$105,789.62	$94,068.19	$107,119.37	$61,894.39	$1,329.75	13.87%	$13,051.1754
Effect of proposed commodity change on average annual bills:									$13,051.18
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,948**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.8586	$4.0713	($0.0096)	14.71%	$0.8794
Demand Cost	$10.1223	$12.9002	$13.1430	$12.0195	$12.0195	$1.8972	($1.1235)	0.00%	$0.0000
Commodity Margin	$0.9000	$0.9000	$0.9000	$1.2434	$1.2434	$0.3434	$0.3434	0.00%	$0.0000
Demand Margin	$1.5000	$1.5000	$1.5000	$2.0724	$2.0724	$0.5724	$0.5724	0.00%	$0.0000
Total Cost of Gas	$3.6873	$6.0834	$7.7682	$7.2226	$8.1020	$4.4147	$0.3338	12.18%	$0.8794
Total Demand Cost	$11.6223	$14.4002	$14.6430	$14.0919	$14.0919	$2.4696	($0.5511)	0.00%	$0.0000
Avg Annual Cost	$18,535.32	$30,460.67	$38,803.13	$36,089.72	$40,440.99	$21,905.68	$1,637.86	12.06%	$4,351.2712
Effect of proposed commodity change on average annual bills:									$4,351.27
Effect of proposed demand change on average annual bills:									$0.00
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$1.6138	$5.1834	$6.8682	$5.9792	$6.8586	$5.2448	($0.0096)	14.71%	$0.8794
Demand Cost	$10.1223	$12.9002	$13.1430	$12.0195	$12.0195	$1.8972	($1.1235)	0.00%	$0.0000
Commodity Margin	$1.8069	$0.2600	$0.2600	$0.3592	$0.3592	($1.4477)	$0.0992	0.00%	$0.0000
Demand Margin	$1.2000	$1.2000	$1.2000	$1.6579	$1.6579	$0.4579	$0.4579	0.00%	$0.0000
Total Cost of Gas	$3.4207	$5.4434	$7.1282	$6.3384	$7.2178	$3.7971	$0.0896	13.87%	$0.8794
Total Demand Cost	$11.3223	$14.1002	$14.3430	$13.6774	$13.6774	$2.3551	($0.6656)	0.00%	$0.0000
Avg Annual Cost	$51,615.78	$81,843.01	$106,865.34	$95,094.00	$108,145.17	$18,846.93	$1,279.83	13.72%	$13,051.1754
Effect of proposed commodity change on average annual bills:									$13,051.18
Effect of proposed demand change on average annual bills:									$0.00

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-05-1403

Illustration of the Effect of Moving FDD Storage Contracts From Demand Costs to Commodity Costs

MERC-PNG **SCHEDULE A**
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) **Page 2 of 3**
NNG Current Commodity Costs

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-08**

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$7.5776	$15.1530	$10.7340	$0.0000	$10.7340
TF-12V	$9.0926	$6.4838	$8.0056	$0.0000	$8.0056
TF-5		$7.6050	$7.6050	$0.0000	$7.6050
TFX	$4.5600	$9.6288	$6.6720	$0.0000	$6.6720
FIELD TF			$0.0000	$0.0000	$0.0000
Commodity From Schedule D					$6.6668

V. ANNUAL SALES -- As filed in Docket No. G007,011/MR-08-836
Total Northern Annual Sales 209,429,630 therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-08**

	Contract Type	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	GS-1 Rate Case Sales (therm)	Rate ($/therm)
A. GS-1	TF12-B (Max Rate)	Annual	25,469	12	$7.5776	$2,315,922	189,613,000	$0.01221
	TF12-V (Max Rate)	Annual	32,690	12	$9.0926	$3,566,839	189,613,000	$0.01881
	TF5 (Max Rate)	Winter	26,064	5	$15.1530	$1,974,739	189,613,000	$0.01041
	TF12B (Discount-Winter)	Winter	4,437	12	$6.4838	$345,225	189,613,000	$0.00182
	TF5 (Discount-Winter)	Winter	763	5	$7.6050	$29,013	189,613,000	$0.00015
	TFX5 (Discount)	Winter	6,000	5	$4.5600	$136,800	189,613,000	$0.00072
	TFX12 (Max Rate)	Annual	9,724	12	$9.6288	$1,123,569	189,613,000	$0.00593
	TFX Apr (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX Oct (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX5 (Max Rate)	Winter	46,558	5	$15.1530	$3,527,467	189,613,000	$0.01860
	TFX5 (Discount)	Winter	2,196	5	$13.8736	$152,332	189,613,000	$0.00080
	TFX5 (Discount)	Winter	1,800	5	$7.6050	$68,445	189,613,000	$0.00036
	TFX12 (Discount)	Annual	414	12	$4.8667	$24,178	189,613,000	$0.00013
	TFX12 (Discount)	Annual	8,271	12	$5.4570	$541,618	189,613,000	$0.00286
	TFX7 (Discount)	Summer	10,837	7	$2.2204	$168,437	189,613,000	$0.00089
	TFX5 (Discount)	Winter	122	5	$4.8667	$2,969	189,613,000	$0.00002
	TFX5 (Discount)	Winter	2,445	5	$5.4570	$66,712	189,613,000	$0.00035
	TFX5 (Discount)	Winter	31,009	5	$15.1475	$2,348,544	189,613,000	$0.01239
	SMS	Annual	20,537	12	$2.1800	$537,248	189,613,000	$0.00283
	Option	Winter	26,323	3	$4.3463	$343,219	189,613,000	$0.00181
	Exchange	Annual	0	1	$2.0035	$0	189,613,000	$0.00000
	Windom	Annual	2,500	12	$0.0000	$0	189,613,000	$0.00000
	Total Demand Cost					**$17,296,008**	189,613,000	**$0.09122**

GS-1 Demand Current Cost of Gas/therm	**$0.09122**
GS-1 Commodity Current Cost of Gas/therm	**$0.68586**
Total GS-1 Current Cost of Gas/therm	**$0.77708**

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

	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therm)	Rate ($/therm)
FDD - Reservation	Annual	68,309	12	$1.7140	$1,404,980	209,429,630	$0.00671
FDD - Storage Cycle	Annual	787,676	5	$0.3567	$1,404,820	209,429,630	$0.00671
FDD - Reservation	Annual	5,026	12	$3.3157	$199,976	209,429,630	$0.00095
FDD - Storage Cycle	Annual	57,953	5	$0.6901	$199,967	209,429,630	$0.00095
FDD - Reservation	Annual	3,141	12	$1.7140	$64,604	209,429,630	$0.00031
FDD - Storage Cycle	Annual	36,221	5	$0.3567	$64,600	209,429,630	$0.00031
Firm Deferred Delivery Storage Contracts					$3,338,947	209,429,630	$0.01594
Call Option Premium					$677,180	209,429,630	$0.00323

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	20,942,963	x	$6.6668	$139,622,546	209,429,630	$0.66668
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$143,638,673	209,429,630	**$0.68586**

CURRENT FIRM TRANSPORTATION COST OF GAS (therm) $1.07340

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C, Page 1 of 1) $1.14418

Illustration of the Effect of Moving FDD Storage Contracts From Demand Costs to Commodity Costs

MERC-PNG **Schedule C**

CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) **Page 1 of 1**

NNG CURRENT GAS COST

EFFECTIVE DATE: 11/01/08

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Month	Cost/Unit		Cost	$/Ccf
TF12-B (Max Rate)	25,469	12	$7.5776	=	$2,315,922	$0.15631
TF12-V (Max Rate)	32,690	12	$9.0926	=	$3,566,839	$0.24073
TF5 (Max Rate)	26,064	5	$15.1530	=	$1,974,739	$0.13328
TF12B (Discount-Wint	4,437	12	$6.4838	=	$345,225	$0.02330
TF5 (Discount-Winter)	763	5	$7.6050	=	$29,013	$0.00196
TFX5 (Discount)	6,000	5	$4.5600	=	$136,800	$0.00923
TFX12 (Max Rate)	9,724	12	$9.6288	=	$1,123,569	$0.07583
TFX Apr (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00077
TFX Oct (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00077
TFX5 (Max Rate)	46,558	5	$15.1530	=	$3,527,467	$0.23808
TFX5 (Discount)	2,196	5	$13.8736	=	$152,332	$0.01028
TFX5 (Discount)	1,800	5	$7.6050	=	$68,445	$0.00462
TFX12 (Discount)	414	12	$4.8667	=	$24,178	$0.00163
TFX12 (Discount)	8,271	12	$5.4570	=	$541,618	$0.03655
TFX7 (Discount)	10,837	7	$2.2204	=	$168,437	$0.01137
TFX5 (Discount)	122	5	$4.8667	=	$2,969	$0.00020
TFX5 (Discount)	2,445	5	$5.4570	=	$66,712	$0.00450
TFX5 (Discount)	31,009	5	$15.1475	=	$2,348,544	$0.15851
FDD - Storage Cycle	57,953	0	$0.6901	=	$0	$0.00000
FDD - Storage Cycle	36,221	0	$0.3567	=	$0	$0.00000
SMS	20,537	12	$2.1800	=	$537,248	$0.03626
FDD - Storage Cycle	787,676	0	$0.3567	=	$0	$0.00000
FDD - Reservation	5,026	0	$3.3157	=	$0	$0.00000
FDD - Reservation	3,141	0	$1.7140	=	$0	$0.00000
FDD - Reservation	68,309	0	$1.7140	=	$0	$0.00000
			TOTAL		$16,952,789	
			Annualized Entitlement		14,816,590	
			Demand Component		$1.14418	$1.14418

MINNESOTA ENERGY RESOURCES - PNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2008
NNG

All costs in $/MMBtu	Last Rate Case G011/ MR03-1372	Last Demand Change G011- M-06- Oct .06	Last Demand Change G011- M-07- Oct. 07	Most Recent PGA Oct. 2008	Current Proposal Effective Nov.1,2008	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service: Avg. Annual Use:		**127**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.6991	$3.9118	($0.1691)	12.04%	$0.7199
Demand Cost	$0.7886	$1.1097	$1.1741	$1.0903	$1.0883	$0.2997	($0.0858)	-0.18%	($0.0020)
Commodity Margin	$1.2628	$1.1771	$1.1771	$1.6263	$1.6263	$0.3635	$0.4492	0.00%	$0.0000
Total Cost of Gas	$4.8387	$7.4702	$9.2194	$8.6958	$9.4137	$4.5750	$0.1943	8.26%	$0.7179
Avg Annual Cost	$614.51	$948.72	$1,170.86	$1,104.37	$1,195.54	$581.03	$24.68	8.26%	$91.1733
Effect of proposed commodity change on average annual bills:									$91.43
Effect of proposed demand change on average annual bills:									($0.25)
2) Small Vol. Interruptible: Avg. Annual Use:		**4,948**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.6991	$3.9118	($0.1691)	12.04%	$0.7199
Demand Cost	$0.0000								
Commodity Margin	$0.9000	$0.9000	$0.9000	$1.2434	$1.2434	$0.3434	$0.3434	0.00%	$0.0000
Total Cost of Gas	$3.6873	$6.0834	$7.7682	$7.2226	$7.9425	$4.2552	$0.1743	9.97%	$0.7199
Avg Annual Cost	$18,244.76	$30,100.66	$38,437.05	$35,737.42	$39,299.49	$21,054.73	$862.44	9.97%	$3,562.0652
Effect of proposed commodity change on average annual bills:									$3,562.07
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**14,841**		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.6991	$3.9118	($0.1691)	12.04%	$0.7199
Demand Cost									
Commodity Margin	$0.2600	$0.2600	$0.2600	$0.3592	$0.3592	$0.0992	$0.0992	0.00%	$0.0000
Total Cost of Gas	$3.0473	$5.4434	$7.1282	$6.3384	$7.0583	$4.0110	($0.0699)	11.36%	$0.7199
Avg Annual Cost	$45,224.98	$80,785.50	$105,789.62	$94,068.19	$104,752.23	$59,527.25	($1,037.39)	11.36%	$10,684.0359
Effect of proposed commodity change on average annual bills:									$10,684.04
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**4,948**		**Mcf**					
		25		**Mcf**					
Commodity Cost	$2.7873	$5.1834	$6.8682	$5.9792	$6.6991	$3.9118	($0.1691)	12.04%	$0.7199
Demand Cost	$10.1223	$12.9002	$13.1430	$12.0195	$12.0195	$1.8972	($1.1235)	0.00%	$0.0000
Commodity Margin	$0.9000	$0.9000	$0.9000	$1.2434	$1.2434	$0.3434	$0.3434	0.00%	$0.0000
Demand Margin	$1.5000	$1.5000	$1.5000	$2.0724	$2.0724	$0.5724	$0.5724	0.00%	$0.0000
Total Cost of Gas	$3.6873	$6.0834	$7.7682	$7.2226	$7.9425	$4.2552	$0.1743	9.97%	$0.7199
Total Demand Cost	$11.6223	$14.4002	$14.6430	$14.0919	$14.0919	$2.4696	($0.5511)	0.00%	$0.0000
Avg Annual Cost	$18,535.32	$30,460.67	$38,803.13	$36,089.72	$39,651.79	$21,116.47	$848.66	9.87%	$3,562.0652
Effect of proposed commodity change on average annual bills:									$3,562.07
Effect of proposed demand change on average annual bills:									$0.00
5) Large Vol. Firm: Avg. Annual Use:		**14,841**		**Mcf**					
		75		**Mcf**					
Commodity Cost	$1.6138	$5.1834	$6.8682	$5.9792	$6.6991	$5.0853	($0.1691)	12.04%	$0.7199
Demand Cost	$10.1223	$12.9002	$13.1430	$12.0195	$12.0195	$1.8972	($1.1235)	0.00%	$0.0000
Commodity Margin	$1.8069	$0.2600	$0.2600	$0.3592	$0.3592	($1.4477)	$0.0992	0.00%	$0.0000
Demand Margin	$1.2000	$1.2000	$1.2000	$1.6579	$1.6579	$0.4579	$0.4579	0.00%	$0.0000
Total Cost of Gas	$3.4207	$5.4434	$7.1282	$6.3384	$7.0583	$3.6376	($0.0699)	11.36%	$0.7199
Total Demand Cost	$11.3223	$14.1002	$14.3430	$13.6774	$13.6774	$2.3551	($0.6656)	0.00%	$0.0000
Avg Annual Cost	$51,615.78	$81,843.01	$106,865.34	$95,094.00	$105,778.04	$18,057.72	($1,087.31)	11.24%	$10,684.0359
Effect of proposed commodity change on average annual bills:									$10,684.04
Effect of proposed demand change on average annual bills:									$0.00

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-05-1403

MERC-PNG **SCHEDULE A**
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) **Page 2 of 3**
NNG Current Commodity Costs

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE **01-Nov-08**

	Tariff-Summer(7)	Tariff-Winter(5)	Wt. Annual	GRI	Total
TF-12B	$7.5776	$15.1530	$10.7340	$0.0000	$10.7340
TF-12V	$9.0926	$6.4838	$8.0056	$0.0000	$8.0056
TF-5		$7.6050	$7.6050	$0.0000	$7.6050
TFX	$4.5600	$9.6288	$6.6720	$0.0000	$6.6720
FIELD TF			$0.0000	$0.0000	$0.0000
Commodity From Schedule D					$6.6668

V. ANNUAL SALES -- As filed in Docket No. G007,011/MR-08-836
Total Northern Annual Sales 209,429,630 therms

VI. PNG'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-08**

	Contract Type	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	GS-1 Rate Case Sales (therm)	Rate ($/therm)
A. GS-1	TF12-B (Max Rate)	Annual	25,469	12	$7.5776	$2,315,922	189,613,000	$0.01221
	TF12-V (Max Rate)	Annual	32,690	12	$9.0926	$3,566,839	189,613,000	$0.01881
	TF5 (Max Rate)	Winter	26,064	5	$15.1530	$1,974,739	189,613,000	$0.01041
	TF12B (Discount-Winter)	Winter	4,437	12	$6.4838	$345,225	189,613,000	$0.00182
	TF5 (Discount-Winter)	Winter	763	5	$7.6050	$29,013	189,613,000	$0.00015
	TFX5 (Discount)	Winter	6,000	5	$4.5600	$136,800	189,613,000	$0.00072
	TFX12 (Max Rate)	Annual	9,724	12	$9.6288	$1,123,569	189,613,000	$0.00593
	TFX Apr (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX Oct (Max Rate)	Month	2,000	1	$5.6830	$11,366	189,613,000	$0.00006
	TFX5 (Max Rate)	Winter	46,558	5	$15.1530	$3,527,467	189,613,000	$0.01860
	TFX5 (Discount)	Winter	2,196	5	$13.8736	$152,332	189,613,000	$0.00080
	TFX5 (Discount)	Winter	1,800	5	$7.6050	$68,445	189,613,000	$0.00036
	TFX12 (Discount)	Annual	414	12	$4.8667	$24,178	189,613,000	$0.00013
	TFX12 (Discount)	Annual	8,271	12	$5.4570	$541,618	189,613,000	$0.00286
	TFX7 (Discount)	Summer	10,837	7	$2.2204	$168,437	189,613,000	$0.00089
	TFX5 (Discount)	Winter	122	5	$4.8667	$2,969	189,613,000	$0.00002
	TFX5 (Discount)	Winter	2,445	5	$5.4570	$66,712	189,613,000	$0.00035
	TFX5 (Discount)	Winter	31,009	5	$15.1475	$2,348,544	189,613,000	$0.01239
	SMS	Annual	20,537	12	$2.1800	$537,248	189,613,000	$0.00283
	FDD - Reservation	Annual	68,309	12	$1.7140	$1,404,980	189,613,000	$0.00741
	FDD - Storage Cycle	Annual	787,676	5	$0.3567	$1,404,820	189,613,000	$0.00741
	FDD - Reservation	Annual	5,026	12	$3.3157	$199,976	189,613,000	$0.00105
	FDD - Storage Cycle	Annual	57,953	5	$0.6901	$199,967	189,613,000	$0.00105
	FDD - Reservation	Annual	3,141	12	$1.7140	$64,604	189,613,000	$0.00034
	FDD - Storage Cycle	Annual	36,221	5	$0.3567	$64,600	189,613,000	$0.00034
	Option	Winter	26,323	3	$4.3463	$343,219	189,613,000	$0.00181
	Exchange	Annual	0	1	$2.0035	$0	189,613,000	$0.00000
	Windom	Annual	2,500	12	$0.0000	$0	189,613,000	$0.00000
	Total Demand Cost					**$20,634,955**	189,613,000	**$0.10883**

GS-1 Demand Current Cost of Gas/therm	**$0.10883**
GS-1 Commodity Current Cost of Gas/therm	**$0.66991**
Total GS-1 Current Cost of Gas/therm	**$0.77874**

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

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	20,942,963	x	$6.6668	$139,622,546	209,429,630	$0.66668
Call Option Premium				$ 677,179.64	209,429,630	$0.00323
GS-1, SVI-1, SJ-1, LJ-1, SLV Commodity Current Cost of Gas/therm				$140,299,726	209,429,630	**$0.66991**

CURRENT FIRM TRANSPORTATION COST OF GAS (therm) $1.07340

C. JOINT RATE DEMAND CALCULATION (SEE SCHEDULE C, Page 1 of 1) $1.03925

MERC-PNG **Schedule C**
CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) **Page 1 of 1**
NNG CURRENT GAS COST
EFFECTIVE DATE: 11/01/08

COSTS ASSIGNED IN COMMODITY:

COSTS ASSIGNED IN JOINT RATE:

	Units	Month	Cost/Unit		Cost	$/Ccf
TF12-B (Max Rate)	25,469	12	$7.5776	=	$2,315,922	$0.11861
TF12-V (Max Rate)	32,690	12	$9.0926	=	$3,566,839	$0.18268
TF5 (Max Rate)	26,064	5	$15.1530	=	$1,974,739	$0.10114
TF12B (Discount-Wint	4,437	12	$6.4838	=	$345,225	$0.01768
TF5 (Discount-Winter)	763	5	$7.6050	=	$29,013	$0.00149
TFX5 (Discount)	6,000	5	$4.5600	=	$136,800	$0.00701
TFX12 (Max Rate)	9,724	12	$9.6288	=	$1,123,569	$0.05754
TFX Apr (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00058
TFX Oct (Max Rate)	2,000	1	$5.6830	=	$11,366	$0.00058
TFX5 (Max Rate)	46,558	5	$15.1530	=	$3,527,467	$0.18066
TFX5 (Discount)	2,196	5	$13.8736	=	$152,332	$0.00780
TFX5 (Discount)	1,800	5	$7.6050	=	$68,445	$0.00351
TFX12 (Discount)	414	12	$4.8667	=	$24,178	$0.00124
TFX12 (Discount)	8,271	12	$5.4570	=	$541,618	$0.02774
TFX7 (Discount)	10,837	7	$2.2204	=	$168,437	$0.00863
TFX5 (Discount)	122	5	$4.8667	=	$2,969	$0.00015
TFX5 (Discount)	2,445	5	$5.4570	=	$66,712	$0.00342
TFX5 (Discount)	31,009	5	$15.1475	=	$2,348,544	$0.12028
FDD - Storage Cycle	57,953	5	$0.6901	=	$199,967	$0.01024
FDD - Storage Cycle	36,221	5	$0.3567	=	$64,600	$0.00331
SMS	20,537	12	$2.1800	=	$537,248	$0.02752
FDD - Storage Cycle	787,676	5	$0.3567	=	$1,404,820	$0.07195
FDD - Reservation	5,026	12	$3.3157	=	$199,976	$0.01024
FDD - Reservation	3,141	12	$1.7140	=	$64,604	$0.00331
FDD - Reservation	68,309	12	$1.7140	=	$1,404,980	$0.07196
			TOTAL		$20,291,736	
			Annualized Entitlement		19,525,290	
			Demand Component		$1.03925	$1.03925

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Sarah J. Kerbeshian, being first duly sworn on oath, deposes and states that on the 12th day of August, 2009, the Response Comments of Minnesota Energy Resources Corporation were electronically filed with the Minnesota Public Utilities Commission and the Minnesota Department of Commerce. A copy of the filing was delivered by first class mail to the remaining individuals on the attached service list.

/s/ Sarah J. Kerbeshian

Subscribed and sworn to before me
this 12th day of August, 2009.

/s/ Paula R. Bjorkman
Notary Public, State of Minnesota

Burl W. Haar
MN Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101-5147

Sharon Ferguson
MN Department of Commerce
85 Seventh Place East
Suite 500
St. Paul, MN 55101-2198

Julia Anderson
Attorney General's Office
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Ronald M. Giteck
Attorney General's Office-RUD
900 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101

Karen Finstad Hammel
Attorney General's Office
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

John Lindell
Attorney General's Office-RUD
900 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2130

Robert S. Lee
Mackall Crounse & Moore PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402-2859

Michael Ahern
Dorsey & Whitney LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402-1498

Ann Seha
Dorsey & Whitney LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402-1498

Michael J. Bradley
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis, MN 55402-4129

Marie Doyle
CenterPoint Energy
800 LaSalle Avenue – Fl. 11
P.O. Box 59038
Minneapolis, MN 55459-0038

Jack Kegel
MN Municipal Utilities Assn.
3025 Harbor Lane N.
Suite 400
Plymouth, MN 55447-5142

James D. Larson
Dahlen Berg & Co.
200 South Sixth Street
Suite 300
Minneapolis, MN 55402

Pam Marshall
Energy CENTS Coalition
823 East Seventh Street
St. Paul, MN 55106

Brian Meloy
Leonard, Street & Deinard
150 South Fifth Street
Suite 2300
Minneapolis, MN 55402

Eric F. Swanson
Winthrop & Weinstine
225 South Sixth Street
Suite 350
Minneapolis, MN 55402-4629

James R. Talcott
Northern Natural Gas Company
1111 South 103rd Street
Omaha, NE 68124

Greg Walters
Minnesota Energy Resources
3460 Technology Drive NW
Rochester, MN 55901