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February 18, 2011

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

RE: **Comments of the Minnesota Office of Energy Security**
Docket No. G007/M-10-1166

Dear Dr. Haar:

Attached are the comments of the Minnesota Office of Energy Security (OES) in the following matter:

> A request by Minnesota Energy Resources Corporation-NMU (MERC-NMU, MERC, or Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand units effective November 1, 2010.

The filing was submitted on November 1, 2010 and revised on November 4, 2010. The petitioner is:

> Gregory J. Walters
> Minnesota Energy Resources Corporation
> 3460 Technology Drive NW
> Rochester, MN 55901

The OES recommends that the Commission disallow MERC's implementation of 5,713 Dkt/day in demand costs, amounting to a disallowance of approximately $312,031. The OES also recommends that the Commission require MERC to refund a portion of the Bison Contract in the Company's upcoming true-up to be filed on, or about, September 1, 2011.

The OES recommends that MERC modify its monthly Purchased Gas Adjustment (PGA) filing, as soon as possible, to reflect the correct duration of time that the Bison contract is in place this year.

Finally, the OES recommends that MERC provide the following in its *Reply Comments*:

- a full discussion that explains how the Company accounts for the 7,000 Dkt/day related to the reallocation of Viking contracts in its PGAs and which volumes, by contract, are recovered from each of MERC's PGA systems;
- 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 OES Information Request No. 7 when considering entering into the Bison Contract;
- 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;

- a discussion clarifying when the Bison pipeline entered service;
- a full explanation detailing whether its design-day approach produces reasonable estimates; and
- a full explanation detailing the reasonableness of its reserve margin and procured entitlement level.

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

Sincerely,

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

AJH/sm
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA OFFICE OF ENERGY SECURITY

DOCKET NO. G007/M-10-1166

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation-NMU (MERC-NMU, MERC, or Company) filed a change in demand petition (*Petition)* on November 1, 2010. Subsequent to this filing, the Company observed an error in an allocation calculation which resulted in an incorrect volume number. Therefore, MERC-NMU filed a *Revised Petition* with the Minnesota Public Utilities Commission (Commission) on November 4, 2010. In its *Revised Petition*, MERC requested that the Commission accept the following changes in the Company's overall level of contracted capacity.

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	**Proposed Changes increase (decrease) (Dkt)[1]**
NNG TF 12 Base and Variable	(4,605)
NNG TF5	1,502
NNG TFX12	3,495
NNG TFX5	3,620
LS Power	424

The Company's proposal would increase the Company's proposed design-day (winter) capacity by 4,436 Dkt.

The OES discusses the various effects on the Company's rates for different customer classes below; however, the OES notes that MERC-NMU's proposal would increase rates for the Company's firm-service customers. For example, MERC-NMU's proposal would increase demand rates for residential customers (who are part of the General Service rate class) by $0.2337 per Dkt or approximately $21.03 per year for customers using 90 Dkt. According to the Company, this amount represents a 22.88 percent increase in demand costs over those charged in

[1] Dekatherms (Dkt).

the October 2010 Purchased Gas Adjustment (PGA) filing. Of course, the percentage increase in customer bills is a much lower percentage, an annual increase of approximately 2.4 percent.[2]

The Company requests that the Commission allow recovery of the associated demand costs in its monthly PGA effective November 1, 2010. However, the OES cannot recommend recovery of all of these costs. As discussed further below, the OES recommends that the Commission disallow MERC's implementation of 5,713 Dkt/day or approximately $312,031 in costs.

MERC-NMU describes the factors contributing to the need for changing demand as follows:[3]

- an allocation of 7,000 Dkt of Northern Natural Gas (Northern) capacity that had historically been assigned to MERC-NMU and MERC-PNG Viking being allocated, instead, to MERC-NMU and MERC-PNG Northern;
- a change in the allocation process used to apportion capacity associated with the LS Power contract. This capacity is now allocated based upon the forecasted design day; and
- Replacement of its Chisago backhaul contracts with 5,902 Dkt/day of winter capacity, on demand, through a Wadena Call Option available on MERC's Viking pipeline. This contract represents a decrease in ratepayer costs compared to the Chisago backhaul.

The OES appreciates the explanations provided by MERC in its *Petition*; however, the OES has concerns regarding the Company's reserve margin and also with the 7,000 Dkt of capacity that was transferred to customers taking gas from Northern. Specifically, while reviewing this *Petition* and MERC's companion filing in its MERC-PNG Northern demand entitlement filing, Docket No. G011/M-10-1068, the OES is unclear whether 7,000 Dkt is allocated between the two PGAs or if the 7,000 Dkt is being recovered in full from both groups, which would suggest a double recovery issue. Therefore, the OES recommends that MERC-NMU provide, in its *Reply Comments*, a full discussion that explains how it accounts for the 7,000 Dkt in its PGAs and also which volumes, by contract, are recovered from each PGA system. In terms of the reserve margin, the OES discusses these concerns in greater detail in Section II(D) below.

The Company also made changes to non-capacity items in the November 2010 PGA compared to the October 2010 PGA as follows:

- Increased the amount of volumes associated with its TFX April and TFX October contracts;
- Terminated its Nexen PSO balancing contract and replaced it with AECO Storage. This storage gas is then delivered to MERC's system through a swap agreement at the Emerson Hub; and

[2] Calculated as $21.03 divided by the annual bills of ($74*12).
[3] *Petition*, page 17.

- Contracted for 5,411 Dkt/day of capacity on the Bison Pipeline (Bison) which then delivers these volumes into Northern Border Pipeline (NBPL). This arrangement allows MERC to access gas supplies in the Rocky Mountain region.[4]

In terms of the first two bullet points above, the Company provides significant discussion in its *Petition* explaining the reasons why it made these changes. Given these explanations, the OES concludes that these changes are reasonable.

However, the OES has serious concerns associated with MERC's Bison and NBPL contracts, which are discussed in Section II(B) below.

II. THE OES'S ANALYSIS OF THE COMPANY'S PROPOSAL

The OES's analysis of the Company's request includes the following sections:

- the proposed overall demand entitlement level;
- MERC's Bison Contract;
- the design-day requirement;
- the reserve margin; and
- the PGA cost recovery proposal.

Each of these is discussed separately below.

A. PROPOSED OVERALL DEMAND ENTITLEMENT LEVEL

As indicated in OES Attachment 1, the Company proposes to increase its total entitlement level as follows:

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
63,783	**68,219**	**4,436**	**6.95**

The OES analyzes below the proposed changes, the proposed design day requirement, and the proposed reserve margin. Based on the information available at this time, the OES concludes that MERC-NMU has not shown its proposed recovery of demand costs to be reasonable. For example, as discussed further below, the OES has concerns with MERC's proposed reserve margin and Bison contract.

[4] This agreement, and the specifics associated with the Bison Project are discussed in greater detail in Docket No. G007,011/M-08-698.

B. BISON CONTRACT

In its *Petition*, MERC proposes to begin recovering costs associated with its Bison Contract. The Bison Contract allows the Company (through an interconnection with NBPL) to source natural gas supplies from the Rocky Mountain region (specifically in the Powder River Basin of Wyoming) and then deliver these volumes to the Ventura, IA Hub for eventual delivery to MERC's Minnesota customers. The Company's plan to access Rocky Mountain gas was first brought to the attention of the OES and the Commission when MERC made a filing on June 11, 2008 in Docket No. G007,011/M-08-698. In that docket, MERC provided a detailed explanation of the Bison Pipeline Project and further discussed that the Company had the opportunity to secure gas supplies, through an open season, on the Bison Pipeline. MERC explained at that time that dynamics in the natural gas market were changing and that it was necessary to diversify MERC's supply portfolio.

At the time of the June 11, 2008 filing, MERC contracted for approximately 62 percent of its Northern winter capacity from Canadian sources and, under the Bison Contract, the Company would be able to bring this percentage down to approximately 40 percent, which would reduce MERC's reliance upon Canadian gas. The Company saw this scenario as attractive since Rocky Mountain gas was historically cheaper than other gas supplies. Further, natural gas markets in Canada were being affected by proposed royalties legislation in the Canadian province of Alberta (where the majority of Canadian gas is sourced), an appreciating Canadian Dollar, and decreasing supply levels.

In its August 1, 2008 *Comments*, the OES expressed support for MERC's plan since the information MERC provided at the time indicated that total delivered costs would have been under $10 per Mcf. Specifically, the Company provided Exhibit 6 showing estimated "Total Bison Costs" with delivered costs on a yearly basis, through 2018, of approximately $9.00 per Dkt, including total transportation fees of just under $1.00 per Dkt. Therefore, it appeared that MERC's transportation fees were just under $1.00 per Dkt per month, similar to how demand costs are presented in the monthly PGA. For ease of reference, the OES attaches MERC's Exhibit 6 to these comments (OES Attachment 2).

The issue of pre-approving MERC's open season went before the Commission on August 21, 2008; ultimately, the Commission did not take action on the Company's proposal, since the Commission does not generally pre-approve utilities' cost recovery for pipeline contracts.

In more recent conversations with the Company, MERC indicates that, despite how the Company's Exhibit 6 portrayed the information about the cost of the Bison project, MERC intended Exhibit 6 to refer to daily transportation fees, rather than the monthly per-Dkt costs typically used for demand costs in the monthly PGA. Thus, the costs the Company proposes to recover in its monthly PGA for the Bison gas is nearly $25 per Dkt.

While the OES agrees that there is value in diversifying natural gas supplies and sources, there are limits to the value. MERC has not shown that the value of diversification is worth the total demand fees, including NBPL costs, of nearly $25 per Dkt and approximately $10 a Dkt greater than Northern's most expensive seasonal reservation fee.

In an effort to better understand MERC's pricing assumptions and possible alternatives available in 2008, the OES issued detailed discovery requesting historical daily basis prices and forward prices. In the Company's response to OES Information Request No. 7, MERC provided detailed basis price and forward contract information on a daily basis from January 1, 2008 to August 21, 2008 (OES Attachment 3).[5] This period of time is significant since it represents the time frame when MERC was considering whether or not to participate in the Bison Project and also incorporates the date (August 21, 2008) when the Company could have broken its agreement without financial penalty.

After an initial review of these data, the OES concludes that MERC should have performed additional analysis in 2008 to determine the appropriateness of the Bison Contract. Specifically, MERC should have replicated Exhibit 6 in Docket No. G007,011/M-08-698 (included in these *Comments* as Attachment 2) for each trading day over the period January 1, 2008 to August 21, 2008. Since MERC could have chosen to break the agreement without financial penalty, MERC should have undertaken this analysis prior to the critical date, and assigned probabilities to the different future scenarios. Ideally, MERC should have presented this analysis in its initial reasonableness filing, and not the single day analysis that was presented in Docket No. G007,011/M-08-698.

In the daily analysis requested by the OES, MERC provides cost and price data, by forward month through December 2018, for each trading day between January 1, 2008 and August 21, 2008 for the Ventura and Rockies CIG (CIG) Hubs. These daily data are detailed and provide significant insight into market dynamics during the time period when MERC was considering the Bison Contract. Based on a review of these data, and the information provided in Information Request No. 7, it is unclear whether the Bison Contract represented, in 2008, an overall benefit for ratepayers. Although it is true that the Bison Contract showed ratepayer benefits, and at times significant benefits over the consideration period, these benefits quickly disappeared into ratepayer costs during the last two weeks of June 2008 and over most days until August 21, 2008. While MERC did not provide this information in its 2008 Bison filing, most or all of the information was available to MERC at that time.

This quick turnaround in the cost/benefit calculation is illustrated in OES Attachment 4 to these comments. The most telling part in OES Attachment 4 is the second graph, which shows how ratepayer benefits reversed into ratepayer costs. This graph suggests that ratepayer benefits associated with the Bison Contract were symptomatic of short-term conditions and not long-run economic trends. Based on a review of the daily CIG Hub basis spreads, it is clear that the cost advantages associated with the Bison Contract were a result of favorable basis discounts in the

[5] The OES only attaches the written portion of this information request since the supporting documentation is quite voluminous. This additional information is public and is available from the OES upon request.

Rockies ($2.50 less per Dkt than Henry Hub), which then abruptly disappeared when the overall bubble in the natural gas market ended, returning basis spreads to regular levels ($1.40 less per Dkt than Henry Hub). Based on its review of these data, the OES recommends that MERC provide the following in its *Reply Comments*:

- a full discussion detailing whether MERC considered the change in natural gas market dynamics that occurred around July 1, 2008 and what impacts these would have on ratepayers 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 OES Information Request No. 7 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 MERC anticipates it can achieve for these volumes over the life of the contract.

Beyond the decision to enter into the Bison contract, the OES notes that the contract length reported by MERC in the monthly PGA does not reflect actual operations for the Bison pipeline. When the Company filed its demand entitlement *Petition* on November 1, 2010, it was expected that the Bison pipeline would enter service on, or about, December 15, 2010, which was the reason for this contract to have a 10.5 month recovery period. However, based on a review of news releases, it appears that the Bison pipeline did not enter service until the middle of January 2011 (OES Attachment 5).

Thus, MERC should provide, in its *Reply Comments*, a discussion clarifying when the Bison pipeline entered service. MERC should also modify its monthly PGA filing, as soon as possible, to reflect the duration of time that the Bison contract is in place this year. In addition, the Commission should require MERC to refund the difference between the amounts already collected assuming a 10.5 month level and those at the correct contract length; this refund can occur in the Company's upcoming true-up to be filed on, or about, September 1, 2011.

C. DESIGN-DAY REQUIREMENT

The Company used the same basic design-day study as in its previous demand entitlement filing.[6] The OES analyzed this proposal based on peak-day levels from previous periods along with changes since that time. In addition, since MERC-NMU is a consolidated PGA and has various customers that can only receive service from specific interstate pipelines, the OES also analyzed whether each pipeline had sufficient capacity to meet firm need on a peak day. The OES concludes that MERC's design-day study and accompanying entitlements appear to ensure sufficient capacity to serve firm demand on a peak day.

[6] See Docket Nos.G007/M-09-1282.

However, as discussed in Section II(D) below, MERC-NMU's reserve margin is quite high, suggesting that demand levels may be too high. Also, an abnormally high reserve margin raises the possibility that the Company's design-day methodology does not produce reasonable estimates and that MERC's resulting rates may be too high. Given this concern, the OES withholds any recommendation regarding MERC-NMU's design-day analysis until the Company provides a full explanation in its *Reply Comments* detailing whether its design-day approach produces reasonable estimates.

D. RESERVE MARGIN

As indicated in OES Attachment 1, the reserve margin is as follows:

Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year[7]
68,219	**57,662**	**10,557**	**18.31**	**13.61**

MERC-NMU's reserve margin of approximately 18 percent is much higher than the 5 percent level the OES generally considers reasonable. The OES notes that the 4.7 percent reserve margin proposed by the Company in its previous demand entitlement filing was calculated with a negative reserve margin for MERC-NMU's customers served by Northern.[8] When the negative reserve margin is corrected, and assuming a 5 percent reserve margin for these customers, the total entitlement level for MERC-NMU during the 2009-2010 heating season should have been approximately 66,037 Dkt/day, which results in a reserve margin of approximately 8.40 percent.[9] Even when correcting for the 4.33 percent negative reserve margin last year for Northern-served customers, there is still a 9.91 percent increase in the reserve margin. MERC has not shown why it is reasonable for the reserve margin to be so much higher than 5 percent, nor why it is reasonable to increase the Company's reserve margin significantly from previous levels. The main concern associated with a utility carrying an excessive reserve margin is that it subjects ratepayers to paying rates that are unreasonably high.

To bring the MERC-NMU system reserve margin to the five percent threshold, the total entitlement level would need to be decreased by 7,674 Dkt/day to a total of 60,545 Dkt/day. However, as noted in the previous paragraph, a reasonable reserve margin for the 2009-2010 heating season would have been approximately 8.40 percent. Using the 8.40 percent reserve margin, for MERC to bring its entitlement levels within this reserve margin, it would need to decrease its total entitlements by 5,713 Dkt/day.

[7] As shown on OES Attachment 1, the Company's average reserve margin since the 1995-1996 heating season is 4.15 percent.
[8] This issue was raised by the OES in the previous demand entitlement, and the negative reserve margin issue was resolved by MERC in this filing by adjusting its allocators between NMU and PNG to better apportion costs on the Northern pipeline.
[9] (66,037-60,918) divided by 60,918.

Unless MERC can support charging its customers for costs associated with a higher reserve margin than the amount calculated above, the OES recommends that the Commission not allow the Company to recover the costs of the excess demand volumes, resulting in a disallowance of approximately $312,031 (OES Attachment 6). The OES arrives at this figure based on each individual contract's percentage amount of MERC's total entitlement level.[10] For example, if a TFX-5 contract was 5 percent of the total entitlement level, then approximately 286 Dkt/day of the 5,713 Dkt/day difference is allocated to this contract. The OES recommends that MERC fully explain, in its *Reply Comments*, the reasonableness of its reserve margin and procured entitlement level.

E. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed in MERC's Attachment 4 represent the demand entitlements for which the Company's firm customers would pay. In its *Petition*, the Company compares its October 2010 PGA to its November 2010 PGA (the Company's Attachment 7, page 1 of 2). The Company's demand entitlement proposal would result in the following annual rate impacts:[11]

- Annual bill increase of $32.72, or approximately 22.88 percent, related to demand costs for the average General Service customer consuming 140 Dkt annually; and
- Annual bill increase of $1,616.79, or approximately 22.88 percent, related to demand costs for the average Large General Service customer consuming 6,917 Dkt annually.

Given the issues associated with MERC's Bison contract and reserve margin, the OES cannot recommend approval of MERC's proposal. The OES will review MERC-NMU's response to the OES's concerns and provide subsequent recommendations.

III. THE OES'S RECOMMENDATIONS

The OES cannot recommend approval of MERC's petition at this time. At a minimum, the OES recommends that the Commission disallow MERC's implementation of 5,713 Dkt/day in demand costs, amounting to a disallowance of approximately $312,031. The OES also recommends that the Commission require MERC to refund, in the Company's upcoming true-up to be filed on, or about, September 1, 2011, the difference between the amounts already collected at the 10.5 month level and those at the correct contract length for the Bison Contract.

The OES recommends that MERC modify its monthly PGA filing, as soon as possible, to reflect the correct duration of time that the Bison contract is in place this year.

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[10] The OES notes that, in terms of calculating the percentage, it only considers contracts that are used to serve need on a peak day. Therefore, the Bison contract and other non-heating season specific contracts are not included in this calculation.

[11] These annual bill impacts are based on the Company's allocation of FDD Storage contracts to the demand portion of the PGA and not the commodity portion of the PGA as advocated by the OES.

Finally, the OES recommends that MERC provide the following in its *Reply Comments*:

- a full discussion that explains how the Company accounts for the 7,000 Dkt/day related to the reallocation of Viking contracts in its PGAs and which volumes, by contract, are recovered from each of MERC's PGA systems;
- a full discussion detailing whether MERC considered the change in natural gas market dynamics that occurred around July 1, 2008 and what impacts these would have on ratepayers 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 OES Information Request No. 7 when considering entering into the Bison Contract;
- 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 it can achieve for these volumes over the life of the contract;
- a discussion clarifying when the Bison pipeline entered service;
- a full explanation detailing whether its design-day approach produces reasonable estimates; and
- a full explanation detailing the reasonableness of its reserve margin and procured entitlement level.

/sm

OES Attachment 1
Demand Entitlement Analysis
NMU's Customers
As Proposed by MERC-NMU
Docket No. G007/M-10-1166

MERC-NMU

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
Heating Season	(1) DD No.of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)*	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2010-2011	40,400	(735)	-1.79%	57,662	(3,256)	-5.34%	68,219	4,436	6.95%	18.31%
2009-2010	41,135	2,023	5.17%	60,918	(2,808)	-4.41%	63,783	(1,052)	-1.62%	4.70%
2008-2009	39,112	854	2.23%	63,726	2,718	4.46%	64,835	415	0.64%	1.74%
2007-2008	38,258	(225)	-0.58%	61,008	(52)	-0.09%	64,420	1,639	2.61%	5.59%
2006-2007	38,483	275	0.72%	61,060	(1,047)	-1.69%	62,781	(1,553)	-2.41%	2.82%
2005-2006	38,208	(1,608)	-4.04%	62,107	1,404	2.31%	64,334	2,668	4.33%	3.59%
2004-2005	39,816	2,740	7.39%	60,703	(1,491)	-2.40%	61,666	(2,672)	-4.15%	1.59%
2003-2004	37,076	612	1.68%	62,194	7,968	14.69%	64,338	7,945	14.09%	3.45%
2002-2003	36,464	362	1.00%	54,226	(344)	-0.63%	56,393	260	0.46%	4.00%
2001-2002	36,102	415	1.16%	54,570	(1,099)	-1.97%	56,133	0	0.00%	2.86%
2000-2001	35,687	717	2.05%	55,669	1,118	2.05%	56,133	1,210	2.20%	0.83%
1999-2000	34,970	1,097	3.24%	54,551	119	0.22%	54,923	151	0.28%	0.68%
1998-1999	33,873	968	2.94%	54,432	1,551	2.93%	54,772	3,918	7.70%	0.62%
1997-1998	32,905	1,362	4.32%	52,881	2,176	4.29%	50,854	0	0.00%	-3.83%
1996-1997	31,543	790	2.57%	50,705	1,342	2.72%	50,854	(10,270)	-16.80%	0.29%
1995-1996	30,753			49,363			61,124			23.83%
Average:			1.87%			1.14%			0.95%	4.44%
Average (Ex. 2003-2004):			1.88%			0.18%			0.01%	4.51%

Firm Peak Day Sendout

Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess/Def. per Cust. [(7) - (4)]/(1)	(16) Design Day per Customer* (4)/(1)	(17) Entitlement per Customer (7)/(1)	(19) Peak Day Sendout per DD Customer (12)/(1)
2010-2011	unknown	unknown			0.2613	1.4273	1.6886	unknown
2009-2010**	40,588	47,933	1,532	3.30%	0.0696	1.4809	1.5506	1.1653
2008-2009	40,694	46,401	(7,714)	-14.25%	0.0284	1.6293	1.6577	1.1864
2007-2008	38,258	54,115	24,019	79.81%	0.0892	1.5946	1.6838	1.4145
2006-2007	38,483	30,096	(16,324)	-35.17%	0.0447	1.5867	1.6314	0.7821
2005-2006	38,208	46,420	5,014	12.11%	0.0583	1.6255	1.6838	1.2149
2004-2005	38,394	41,406	2,123	5.40%	0.0242	1.5246	1.5488	1.0399
2003-2004	37,632	39,283	(5,858)	-12.98%	0.0578	1.6775	1.7353	1.0595
2002-2003	37,076	45,141	10,769	31.33%	0.0594	1.4871	1.5465	1.2380
2001-2002	36,500	34,372	(9,950)	-22.45%	0.0433	1.5116	1.5548	0.9521
2000-2001	35,956	44,322	3,967	9.83%	0.0130	1.5599	1.5729	1.2420
1999-2000	35,822	40,355	(8,001)	-16.55%	0.0106	1.5599	1.5706	1.1540
1998-1999	34,970	48,356	8,320	20.78%	0.0100	1.6069	1.6170	1.4276
1997-1998	33,873	40,036	(7,904)	-16.49%	-0.0616	1.6071	1.5455	1.2167
1996-1997	33,064	47,940	16,790	53.90%	0.0047	1.6075	1.6122	1.5198
1995-1996	32,112	31,150			0.3824	1.6051	1.9876	1.0129
Average:				7.33%	0.0556	1.5776	1.6332	1.1757
Average (Ex. 2003-2004):				9.02%	0.0555	1.5705	1.6259	1.1847

* The total entitlement includes the 864 Mcf/day of entitlement permanently released to Cornerstone in 2002-2003.
** The number of peak day customers is calculated using firm customer count numbers provided in MERC-NMU's *Initial Filing*, Attachment 12.

Exhibit 6

Year	Total Annual Contracted Volumes	Total Projected Bison Delivered Cost	Total Projected Bison Delivered Unit Cost	Total Projected POM Delivered Cost	Total Projected POM Delivered Unit Cost	Total Projected Ventura Delivered Cost	Total Projected Ventura Delivered Unit Cost
2010	3,050,000	$ 27,999,458	$ 9.1802	$ 31,328,321	$ 10.2716	$ 31,450,675	$ 10.3117
2011	18,250,000	$ 166,966,790	$ 9.1489	$ 181,354,388	$ 9.9372	$ 178,669,125	$ 9.7901
2012	18,300,000	$ 163,998,700	$ 8.9617	$ 180,034,546	$ 9.8380	$ 175,999,300	$ 9.6174
2013	18,250,000	$ 161,691,159	$ 8.8598	$ 178,700,593	$ 9.7918	$ 174,229,125	$ 9.5468
2014	18,250,000	$ 161,300,694	$ 8.8384	$ 178,307,648	$ 9.7703	$ 173,847,625	$ 9.5259
2015	18,250,000	$ 162,495,374	$ 8.9039	$ 179,509,916	$ 9.8362	$ 175,014,875	$ 9.5899
2016	18,300,000	$ 164,575,698	$ 8.9932	$ 181,665,808	$ 9.9271	$ 177,116,800	$ 9.6785
2017	18,250,000	$ 166,217,332	$ 9.1078	$ 183,255,511	$ 10.0414	$ 178,651,375	$ 9.7891
2018	18,250,000	$ 168,895,320	$ 9.2545	$ 185,950,506	$ 10.1891	$ 181,267,875	$ 9.9325
Total	149,150,000	$ 1,344,140,526	$ 9.0120	$ 1,480,107,236	$ 9.9236	$ 1,446,246,775	$ 9.6966

Gas Cost Savings compared to Ventura $ (0.6846)

State of Minnesota

OFFICE OF ENERGY SECURITY

Utility Information Request

Docket Number: G007/M-10-1166 Date of Request: January 10, 2011

Requested From: Minnesota Energy Resources Corporation-NMU Response Due: January 20, 2011

Analyst Requesting Information: Sugarna Balasubramaniam

Type of Inquiry:

[X]...Financial	[ ].....Rate of Return	[ ].....Rate Design
[ ].....Engineering	[ ].....Forecasting	[ ].....Conservation
[ ].....Cost of Service	[ ].....CIP	[ ].....Other:

If you feel your responses are trade secret, please indicate this on your response.

Request No.	
7	Subject: Bison Contract

Reference: Other Revised Demand Entitlement Schedules, Attachment 4, Page 2 of 6

(A) The Other Revised Demand Entitlement Schedules provide two different numbers of months of the Bison contract, 10.5 months and 11 months. Please provide the correct number of months of the Bison contract for the 2010-2011 period.

Response:

At the time of the filing, the expected in-service date for Bison Pipeline was December 15, 2010. That would make it 10.5 months.

(B) Please provide the daily New York Mercantile Exchange (NYMEX) closing prices at the Henry Hub and basis spreads for the Rockies (using the CIG Rocky Mountain Price or some other applicable Rocky Mountain regional hub), Ventura Hub, and Demarcation for each forward contract over the period from January 1, 2008 to August 21, 2008.

Response:

Please see attached Excel file (OES IR 7(B) and (C) Docket No. G007/M-10-1166).

Response by: Shawn Gillespie

Title: Manager

Department: Gas Supply

Telephone: 402-614-0076

List sources of information:

(C) Please provide the daily volatility measures for the points detailed in the previous question (B)for each forward contract over the period from January 1, 2008 to August 21, 2008.

Response:

Please see attached Excel file (OES IR 7(B) and (C) Docket No. G007/M-10-1166).

(D) Please provide a full explanation detailing whether MERC investigated procuring other sources of gas to diversify its supply portfolio.

Response:

MERC considered purchasing supply at Port of Morgan, which is the interconnect between Foothills Pipeline and Northern Border Pipeline (NBPL), and contracting for capacity with NBPL to deliver to NNG. At the time, this option was more expensive than Bison. MERC also considered purchasing Natural Gas Pipeline (NGPL) storage and transportation to deliver into NNG. That option was not explored any further due to the unavailability of firm capacity on NNG at the NGPL interconnect. MERC also considered continuing to buy at the Ventura interconnect.

(E) Please provide a detailed analysis of contract prices available for alternate demand contracts in 2008.

Response:

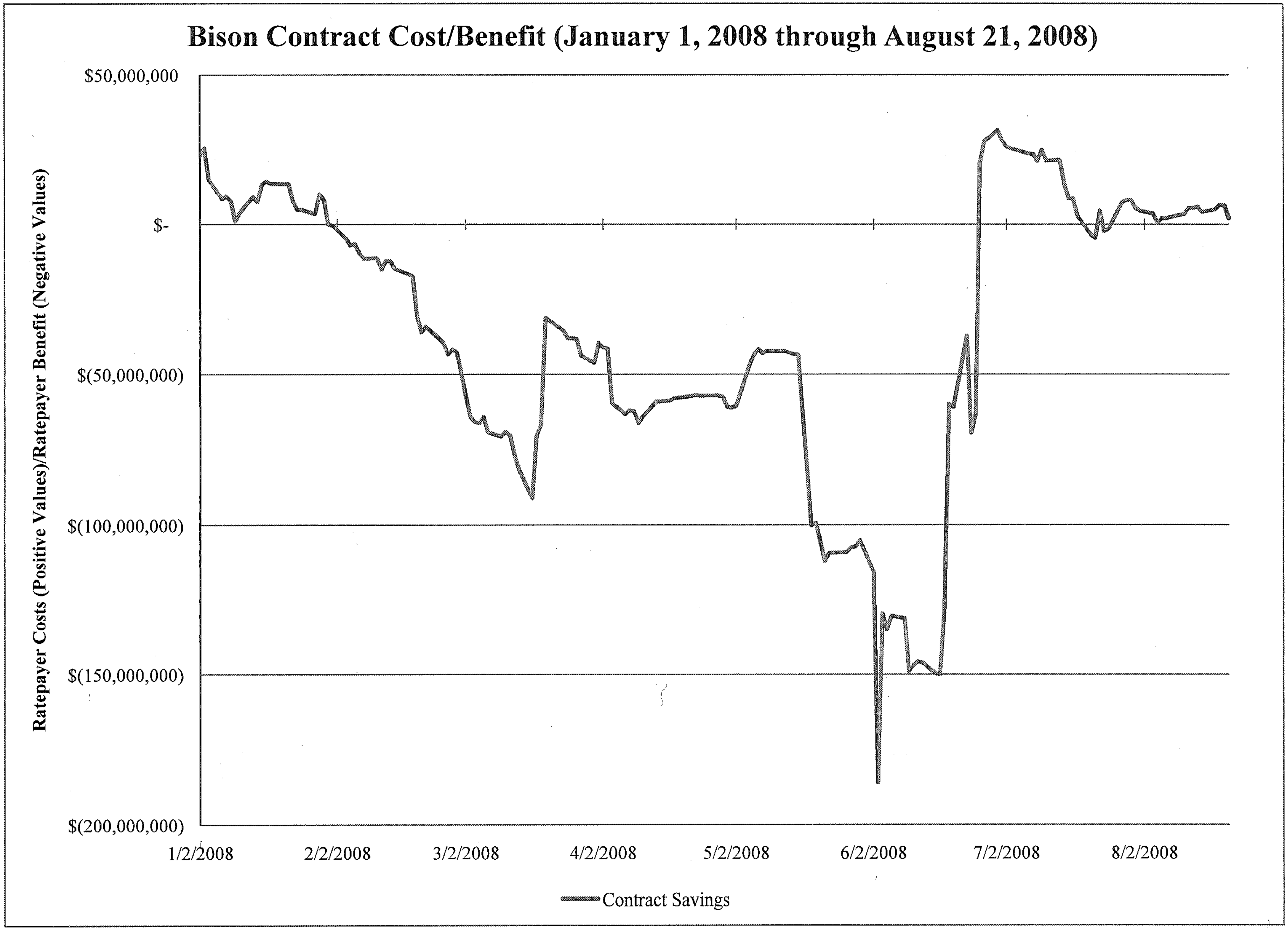
Please see attached Excel file (OES IR 7(E) Docket No. G007/M-10-1166).

(F) Please provide a full list and explanation, including demand and commodity prices and price differences from the Bison contract, of all alternate contracts that MERC considered as alternatives to the Bison contract.

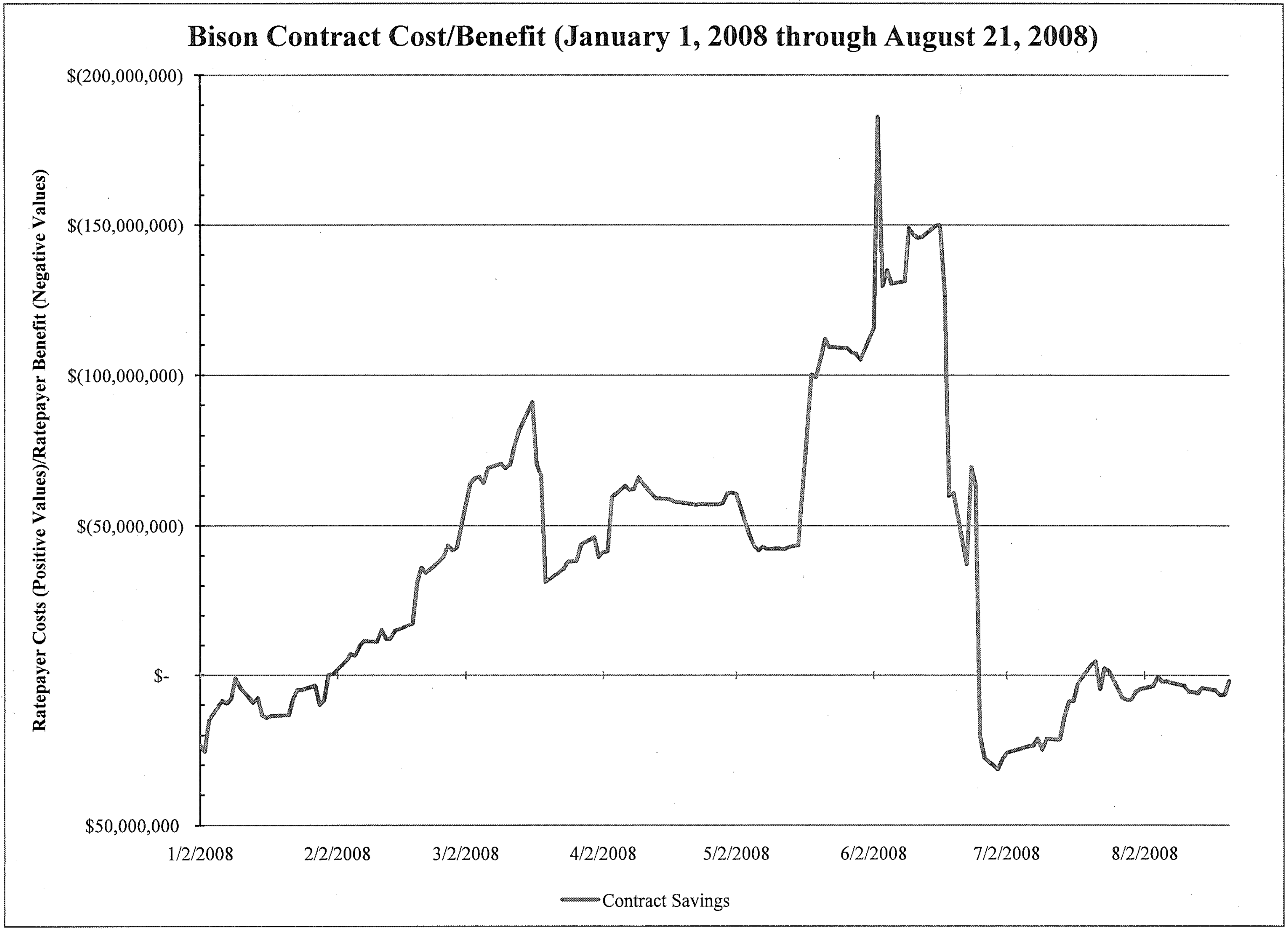
Response:

Please see the response to 7(E), above.

Response by:	Shawn Gillespie	List sources of information:
Title:	Manager	
Department:	Gas Supply	
Telephone:	402-614-0076	



Prepared by the Minnesota Office of Energy Security



Prepared by the Minnesota Office of Energy Security

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TransCanada starts Bison pipeline

Published: Jan. 19, 2011 at 6:28 AM

CALGARY, Alberta, Jan. 19 (UPI) -- Gas flowing through the Bison pipeline marks the first time TransCanada is tapping into markets in the U.S. Rocky Mountain region, the company said.

TransCanada said its 303-mile Bison pipeline starting operating Friday. The $600 million project can carry as much as 407 million cubic feet of natural gas per day in initial capacity.

The Canadian pipeline company said the initial capacity of Bison is filled under long-term contracts. The capacity could be increased to 1 billion cubic feet per day with additional pipeline compression should demand increase.

Russ Girling, the president and chief executive officer at TransCanada, said the pipeline gives his company new options for consumers in the United States.

"The Rockies was one of the last major North American producing basins that we weren't connected to," he added in a statement.

The Bison pipeline starts in northeastern Wyoming and heads through Montana and North Dakota before connecting to an existing pipeline to the Midwest states.

OES Attachment 6
Docket No. G007/M-10-1166
Disallowance Calculation

OES Disallowance Calculation							
Total Proposed Volume Amount	Total Proposed Deliverability	Percentage of Total Deliverability [(A)/(B)]	Volumes above 8.40 Percent Reserve Margin	(Column C) *(Column D)	Months	Contract Cost	Total Cost [(E)*(F)*(G)]
A	B	C	D	E	F	G	H
4,232	68,219	6.20%	5,713	354	12	$7.5776	$32,226.82
3,919	68,219	5.74%	5,713	328	12	$9.0926	$35,809.93
3,493	68,219	5.12%	5,713	293	5	$15.1530	$22,162.87
649	68,219	0.95%	5,713	54	5	$4.5600	$1,239.19
1,171	68,219	1.72%	5,713	98	12	$9.6288	$11,331.02
6,208	68,219	9.10%	5,713	520	5	$15.1530	$39,389.39
195	68,219	0.29%	5,713	16	5	$7.6050	$620.96
139	68,219	0.20%	5,713	12	12	$4.8640	$679.44
895	68,219	1.31%	5,713	75	12	$5.4720	$4,921.63
1,290	68,219	1.89%	5,713	108	12	$2.2192	$2,876.91
41	68,219	0.06%	5,713	3	5	$4.8640	$83.50
265	68,219	0.39%	5,713	22	5	$5.4720	$607.18
2,401	68,219	3.52%	5,713	201	5	$15.1392	$15,220.33
3,149	68,219	4.62%	5,713	264	3	$6.9920	$5,531.64
7,966	68,219	11.68%	5,713	667	12	$3.4671	$27,755.36
5,902	68,219	8.65%	5,713	494	3	$0.9000	$1,334.51
10,130	68,219	14.85%	5,713	848	12	$3.4580	$35,202.58
1,178	68,219	1.73%	5,713	99	12	$3.4580	$4,093.65
2,138	68,219	3.13%	5,713	179	5	$3.4580	$3,095.72
3,000	68,219	4.40%	5,713	251	12	$3.4580	$10,425.25
9,858	68,219	14.45%	5,713	826	12	$5.7964	$57,423.19
68,219		100.00%					**$312,031.07**

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 Office of Energy Security
Comments

Docket No. G007/M-10-1166

Dated this **18th o**f **February**, **2011**

/s/Sharon Ferguson

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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_10-1166_10-1166

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