Minnesota Energy Resources Corporation
Suite 200
1995 Rahncliff Court
Eagan, MN 55122
www.minnesotaenergyresources.com

May 1, 2017

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

VIA ELECTRONIC FILING

Re: In the Matter of the Petition Minnesota Energy Resources Corporation (MERC) for Approval of the 2016 Conservation Improvement Program Tracker Account, Demand-Side Management Financial Incentive, and Conservation Cost Recovery Adjustment Factor
Docket No. G011/M-17-___

Dear Mr. Wolf:

Enclosed please find the Petition of Minnesota Energy Resources Corporation ("MERC") for Approval of its 2016 Conservation Improvement Program ("CIP") Tracker Accounts, Demand-Side Management ("DSM") Financial Incentive, and Conservation Cost Recovery Adjustment ("CCRA").

The Minnesota Public Utilities Commission's ("Commission") October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617 at Order Point 13 also required that MERC include, in future CIP tracker-account filings, annual compliance filings documenting that its CIP-exempt customers have been properly identified and are being properly billed. MERC has included an update regarding CIP billing compliance in the attached report.

Copies of this filing have been served on the Department of Commerce, Division of Energy Resources and the Office of the Attorney General – Residential Utilities and Antitrust Division. A summary of this filing has been served on all parties on the attached service list.

Please contact me at (651) 322-8965 if you have any questions.

Sincerely yours,

Amber S. Lee
Regulatory and Legislative Affairs Manager
Minnesota Energy Resources Corporation

cc: Service List
Enclosure

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matt Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of the 2016 Conservation Improvement Program Tracker Account, Demand-Side Management Financial Incentive, and Conservation Cost Recovery Adjustment Factor	Docket No. G011/M-17-___ **PETITION**

INTRODUCTION

Minnesota Energy Resources Corporation ("MERC or the "Company") submits this Petition pursuant to the Minnesota Public Utilities Commission's ("Commission") ORDER ESTABLISHING UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION in Docket No. E,G999/CI-08-133. In this filing, MERC seeks approval of its Conservation Improvement Program ("CIP") tracker account balance and a Demand-Side Management ("DSM") financial incentive for the period January 1, 2016, through December 31, 2016. MERC is also seeking Commission approval of a proposed modified Conservation Cost Recovery Adjustment ("CCRA"). MERC filed is CIP Status Report covering the same period in Docket No. G011/CIP-12-548.

I. Summary of Filing

A one-paragraph summary of the filing accompanies this Petition pursuant to Minn. R. 7829.1300, subp. 1.

II. Service on Other Parties

Pursuant to Minn. R. 7829.1300, subp. 2, MERC has served a copy of this petition on the Department of Commerce, Division of Energy Resources and the Office of the Attorney General – Residential Utilities and Antitrust Division. A summary of this filing has been served on all parties on the attached service list.

III. General Filing Information

Pursuant to Minn. R. 7825.3200, 7825.3500, and 7829.1300, MERC provides the following information:

A. Name, Address, and Telephone Number of Filing Party

Minnesota Energy Resources Corporation
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
(651) 322-8901

B. Name, Address, Electronic Address, and Telephone Number of Attorney for the Filing Party

Kristin M. Stastny
Briggs and Morgan, P.A.
2200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402
kstastny@briggs.com
(612) 977-8656

C. Date of Filing and Proposed Effective Date

MERC is submitting this filing on May 1, 2017. MERC proposes that the new CCRC factor be effective January 1, 2018.

D. Statute Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.16, subd. 1 allows a utility to place a rate change into effect upon 60-days' notice to the Commission, unless the Commission otherwise orders. Minn. Stat. § 216B.16, subd. 6b-6c further allows public utilities to file rate schedules

providing for annual recovery of actual conservation costs and approved incentives. Under Minn. R. 7829.0100, subp. 11, this Petition constitutes a miscellaneous filing because no determination of the Company's general revenue requirement is necessary. Minn. R. 7829.1400, subp. 1, permits initial comments on miscellaneous filings to be made within 30 days of filing with reply comments 10 days thereafter.

E. Signature, Electronic Address, and Title of Utility Employee Responsible for the Filing

_____

Amber S. Lee
Regulatory and Legislative Affairs Manager
ASLee@minnesotaenergyresources.com
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
(651) 322-8965

IV. Description and Purpose of Filing

A. Background

In this Petition, MERC seeks the Commission's approval of its CIP tracker account balances as of December 31, 2016. Additionally MERC seeks Commission approval of a DSM financial incentive for 2016 in the amount of $0.01024. MERC also seeks Commission approval of a CCRA of $0.01024 per therm, with a proposed effective date of January 1, 2018.

B. 2016 CIP Tracker Account

On May 2, 2016, MERC submitted a petition for approval of its 2015 CIP tracker account activity, DSM financial incentive, and revised CCRA in Docket No. G011/M-16-385. Specifically, MERC requested that the Commission approve the Company's 2015 DSM financial incentive of $3,392,001; approve MERC's 2015 CIP tracker activity; and

approve a revised CCRA of $0.00750 per therm to be effective January 1, 2017. The Commission approved MERC's 2015 CIP Tracker activity and DSM incentive by Order dated August 30, 2016.

The table below provides a summary of activities in the MERC CIP tracker account in 2016.

MERC-CIP Tracker 2016 Activity

Beginning Balance – January 1, 2016	$ 1,269,151.31
CIP Expenses – January 1, 2016 – December 31, 2016	$ 9,198,728.06
Carrying Charges – January 1, 2016 – December 31, 2016	$ (45,725.51)
DSM Financial Incentive	$ 3,392,001.00
CIP Recoveries – January 1, 2016 – December 31, 2016	$ (14,059,910.48)
Adjustments	
Change in CCRA Rate	$ 87,518.07
Ending Balance – December 31, 2016	**$ (158,237.55)**

The adjustment of $87,518.07 relates to the difference between what was manually calculated using the approved CCRA rate for January 2016 and what was actually billed to customers. Attachment A includes MERC's 2016 CIP tracker account activity.

C. Proposed DSM Financial Incentive

1. *Calculation of DSM Financial Incentive*

MERC seeks Commission approval of a DSM financial incentive of $3,245,000 for 2016 based on energy savings of 472,000 dekatherms (Dth). Supporting documentation is provided in Attachment B.

MERC has excluded NGEA assessments in the amount of $185,133 from the calculation of net benefits as provided by the Commission's January 27, 2010, ORDER

ESTABLISHING UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION in Docket No. E,G999/CI-08-133.

2. *Statutory Criteria*

In Docket No. E,G999/CI-08-133, the Commission adopted a new Shared Savings Model to be used to calculate utility financial incentives for energy conservation starting with the calendar year 2010. On December 20, 2012, the Commission issued an ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE in Docket No. E,G999/CI-08-133, whereby the Commission adopted modifications to the shared savings incentive model. Minn. Stat. § 216B.16, subd. 6c(b) sets forth four statutory criteria with respect to approval by the Commission of utility financial incentive plans for energy conservation improvements. MERC's requested DSM financial incentive is consistent with the statutory criteria outlined below.

Minn. Stat. § 216B.16, subd. 6c(b) states that in approving incentive plans, the Commission shall consider:

> (1) whether the plan is likely to increase utility investment in cost-effective energy conservation;
>
> (2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;
>
> (3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and
>
> (4) whether the plan is in conflict with other provisions of Chapter 216B.

The four criteria are discussed below.

(1) Whether the plan is likely to increase utility investment in cost-effective energy conservation.

The Shared Savings Model emphasizes the 1.5 percent energy savings goal and ties the incentives earned by the Company to that goal. Under the model, the Company's incentive is calibrated so that when MERC achieves energy savings equal to 1.5 percent of retail sales, the Company will earn an incentive equal to $6.875 the Mcf saved. Additionally, the closer the energy savings are to reaching the 1.5 percent energy savings goal, the greater the incremental incentive.

MERC's incentive is designed to increase the Company's investment in cost-effective energy conservation and consequently results in increased energy and demand savings. The increasing incentives under the plan encourage MERC to seek energy savings, through completed customer conservation measures, at and beyond the 1.5 percent energy savings goal.

(2) Whether the plan is compatible with the interest of utility ratepayers and other interested parties.

MERC's plan is compatible with the interest of utility ratepayers and other interested parties. The incentive is designed to tie the financial incentive to the utility's progress towards meeting the 1.5 percent energy savings goal. Additionally, the incentive will not exceed the net benefits created through the savings, and therefore ratepayers receive the majority of the benefits achieved under the Company's CIP program. Specifically, the Company's incentive plan caps the incentive awarded at 20 percent of net benefits. Further, the plan caps the incentive awarded per unit of energy saved at 125 percent of MERC's 1.0 percent target calibration ($6.875) per Mcf.

(3) Whether the plan links the incentive to the utility's performance in achieving cost-effective conservation.

MERC's incentive plan links the incentive to the Company's progress toward the 1.5 percent energy savings goal, but the incentive awarded will not exceed the net benefits created through savings. The incentive therefore encourages the utility to achieve cost-effective conservation.

(4) Whether the plan is in conflict with other provisions of Chapter 216B.

MERC's incentive plan does not conflict with other provisions of Chapter 216B, as the Commission concluded in its January 27, 2010, ORDER ESTABLISHING UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION and December 20, 2012, ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE in Docket No. E,G999/CI-08-133.

D. Proposed CCRA

In the Company's 2008 rate case proceeding, the Commission approved a CCRA for the Company with an initial rate of $0.0000 per therm and required the Company to file adjustment reports by May 1 of each calendar year. The current CCRA factor of $0.00750 was approved by the Commission by Order dated August 30, 2016, in Docket No. G011/M-16-385 and was effective January 1, 2017.

MERC's calculation of its new proposed CCRA is based on a January 1, 2018, effective date. The MERC tracker balance as of January 1, 2017, is $(158,237.55). The estimated MERC CIP tracker balance as of January 1, 2018, is $(3,461,377.07). Calculation of the proposed consolidated CCRA factor of $0.01024 per therm is shown in Attachment C.

Included as Attachment D are proposed redline changes to MERC's Tariff Sheet No. 7.02a, incorporating the proposed modified CCRA rate. The Company proposes to

implement the bill message below, effective the first month the new CCRA factor takes effect, notifying customers of the change in their monthly bills:

> Effective January 1, 2018, a CCRA (conservation cost recovery adjustment) of $0.01024 per therm has been included on your bill. The CCRA is an annual adjustment to true-up under-recovery or over-recovery of CIP (conservation improvement program) expenses.

E. Effect of Change on MERC Revenue

This Petition has no effect on MERC revenue. The CCRA is forecasted to recover the difference between the CIP expenses actually recovered through the CCRC and the CIP tracker account balance as of January 2017 over a one-year period.

F. CIP-Exempt Customer Billing Review

In its October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617, the Commission ordered that MERC make annual compliance filings with future CIP tracker filings documenting that its CIP-exempt customers have been properly identified and are being properly billed.

Since the imposition of this requirement, MERC has continued to conduct monthly reviews of a sample of customer bills, across all bill classes, to ensure proper billing of CIP charges. MERC has also committed to review all CIP-exempt rate codes on a quarterly basis to ensure customers who are treated as CIP-exempt have received an exemption. Based on MERC's continued review, all customers on CIP-exempt rate codes have a valid exemption on file and no additional billing issues have been identified.

CONCLUSION

MERC respectfully requests that the Commission approve its CIP tracker account balances for 2016 with an ending balance of $(158,237.55). Additionally,

MERC requests that the Commission approve a consolidated 2016 DSM financial incentive of $3,245,000 Finally, MERC requests approval of a revised CCRA factor of $0.01024 per therm effective January 1, 2018.

DATED: May 1, 2017

Respectfully submitted,

BRIGGS AND MORGAN, P.A.

By: */s/ Kristin M. Stastny*
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Attorney for Minnesota Energy Resources Corporation

ATTACHMENT A

Minnesota Energy Resources
CIP Tracker Balance Calculation
As of 12/31/2016 - FINAL

		PY Ending Balance	January	February	March	April	May	June	July	August	September	October	November	December	CY Total
1.	Beginning Balance (excl. carry cost through July 2015)		1,269,151.31	(541,536.53)	(2,393,993.30)	(3,648,817.58)	(4,272,632.08)	(4,913,990.33)	(4,454,917.30)	(4,570,025.56)	(945,706.06)	(275,622.51)	(460,407.75)	(346,808.46)	1,269,151.31
	Acquired IPL tracker balance														-
2.	Expenses		380,833.88	545,222.55	726,199.10	710,001.08	444,530.60	1,103,317.34	194,958.12	696,513.66	1,105,221.05	397,556.69	1,111,347.01	1,783,026.98	9,198,728.06
3.	Recoveries		(2,278,122.09)	(2,393,622.40)	(1,974,840.01)	(1,326,575.08)	(1,077,561.49)	(636,694.90)	(302,321.91)	(462,592.55)	(434,670.42)	(581,561.71)	(997,160.01)	(1,594,187.92)	(14,059,910.48)
	One-Time Adjustment*		87,518.07												87,518.07
															-
4.	Incentives									3,392,001.00					3,392,001.00
5.	Subtotal Balance Line 1+2-3+4)		(540,618.83)	(2,389,936.38)	(3,642,634.20)	(4,265,391.57)	(4,905,662.97)	(4,447,367.89)	(4,562,281.09)	(944,103.45)	(275,155.44)	(459,627.53)	(346,220.75)	(157,969.39)	(112,512.04)
6.	Monthly Carry Cost ** (Line 5 x .00169750)		(917.70)	(4,056.92)	(6,183.37)	(7,240.50)	(8,327.36)	(7,549.41)	(7,744.47)	(1,602.62)	(467.08)	(780.22)	(587.71)	(268.15)	(45,725.51)
															-
7	**Ending Balance (Line 5+6)**	**1,269,151.31**	**(541,536.53)**	**(2,393,993.30)**	**(3,648,817.58)**	**(4,272,632.08)**	**(4,913,990.33)**	**(4,454,917.30)**	**(4,570,025.56)**	**(945,706.06)**	**(275,622.51)**	**(460,407.75)**	**(346,808.46)**	**(158,237.55)**	**(158,237.55)**

*Calculation reflects change in CCRA rate; however, actual billings do not. Therefore, calculated amount was adjusted.

** Carry Cost charge set at 2.037% based on 2016 Rate Case verbal approval:

2.0370% annual rate
12 months
0.00169750 monthly rate

Effective in August 2015, carrying charges are based on the total net tracker balance inclusive of carrying charges

Minnesota Energy Resources
CCRC Recovery by Class (in therms)
As of 12/31/2016 - FINAL

CCRC:	January	February	March	April	May	June	July	August	September	October	November	December	YTD
Gas Residential	29,271,452	34,766,458	23,958,200	18,449,572	9,251,336.30	5,570,550.00	2,609,838	2,897,572	3,012,265	4,308,822	9,442,677	20,509,907	164,048,649
Gas Small C&I	1,295,444	1,465,457	1,795,895	59,282	685,970.90	(35,574.00)	647,577	(227,024)	(196,760)	148,873	907,701	449,168	6,996,010
Gas Large C&I	15,476,765	17,793,026	15,068,532	8,115,130	7,879,822.40	4,089,800.70	(898,696)	2,429,786	2,029,882	3,218,706	6,929,270	10,485,658	92,617,681
Gas Large C&I Int.	4,450,033	4,093,323	3,813,441	992,433	5,711,040.70	1,932,967.30	316,599	2,135,747	1,114,328	2,288,684	3,700,407	3,986,974	34,535,977
Transport of Gas	12,143,018	7,886,196	9,777,457	8,829,788	6,084,576.00	5,972,653.40	5,648,500	5,500,548	6,008,083	6,047,077	6,474,791	8,461,135	88,833,822
Total Therms	62,636,711	66,004,460	54,413,524	36,446,205	29,612,746	17,530,397	8,323,818	12,736,629	11,967,798	16,012,162	27,454,846	43,892,842	387,032,139
CCRC rate *	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767	0.02767
CCRC Recovery	$ 1,733,157.80	$ 1,826,343.41	$ 1,505,622.22	$ 1,008,466.49	$ 819,384.69	$ 485,066.10	$ 230,320.04	$ 352,422.52	$ 331,148.97	$ 443,056.51	$ 759,675.59	$ 1,214,514.94	$ 10,709,179.29

* CCRC Final rate effective Jan 1, 2016

Minnesota Energy Resources
CCRA Recovery by Class (in therms)
As of 12/31/2016 - FINAL

CCRA:	January	February	March	April	May	June	July	August	September	October	November	December	YTD
Gas Residential	29,272,399	34,766,578	23,957,469	18,446,019	9,250,937.10	5,570,370	2,609,936	2,897,362	3,012,265	4,308,822	9,442,677	20,509,895	164,044,730
Gas Small C&I	1,309,406	1,465,457	1,795,895	59,259	685,970.90	(35,574)	647,576	(227,024)	(196,760)	148,873	907,701	449,168	7,009,947
Gas Large C&I	15,586,430	17,793,026	15,068,502	8,115,129	7,879,822.40	4,088,925	(898,696)	2,429,786	2,029,882	3,218,706	6,929,270	10,485,658	92,726,441
Gas Large C&I Int.	4,464,872	4,093,323	3,813,441	992,433	5,711,040.70	1,932,967	316,599	2,135,747	1,114,328	2,288,684	3,700,407	3,986,974	34,550,815
Transport of Gas	12,368,545	7,463,002	9,609,524	9,162,719	6,319,258	5,972,653	5,648,500	5,500,548	6,008,083	6,047,077	6,474,791	8,461,135	89,035,834
Total Therms	63,001,652	65,581,386	54,244,831	36,775,559	29,847,029	17,529,342	8,323,915	12,736,419	11,967,798	16,012,162	27,454,846	43,892,830	387,367,768
CCRA rate *	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865	0.00865
CCRA Recovery	$ 544,964.29	$ 567,278.99	$ 469,217.79	$ 318,108.59	$ 258,176.80	$ 151,628.80	$ 72,001.86	$ 110,170.02	$ 103,521.45	$ 138,505.20	$ 237,484.42	$ 379,672.98	$ 3,350,731.19

CCRA = Conservation Cost Recovery Adjustment

ATTACHMENT B

	A	B	C	D	E	F	G	H
1	3.1							
2	**Conservation Improvement Program (CIP)**			BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis				
3				Approved by Minnesota Department of Commerce, January 26, 2006				
4	Company: **Minnesota Energy Resources**							
5	Project: **TOTAL CIP - 2016**							
6				R				
7	**Input Data**					**2016 Actual**		
8								
9	1) Retail Rate ($/Dth) =		$16.06		16) Utility Project Costs			
10	Escalation Rate =		4.28%		16a) Administrative & Operating Costs =	$5,387,527		
11					16b) Incentive Costs =	$3,626,067		
12	2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =		$0.00		16c) Total Utility Project Costs =	$9,013,595		
13	Escalation Rate =		2.16%					
14	Non-Gas Fuel Units (ie. kWh,Gallons, etc) =				17) Direct Participant Costs ($/Part.) =	$394		
15								
16	3) Commodity Cost ($/Dth) =		$4.34		18) Participant Non-Energy Costs (Annual $/Part.) =	$0		
17	Escalation Rate =		4.28%		Escalation Rate =	0.00%		
18								
19	4) Demand Cost ($/Unit/Yr) =		$118.53		19) Participant Non-Energy Savings (Annual $/Part) =	$0		
20	Escalation Rate =		4.28%		Escalation Rate =	0.00%		
21								
22	5) Peak Reduction Factor =		1.00%		20) Project Life (Years) =	13.9		
23								
24	6) Variable O&M ($/Dth) =		$0.03		21) Avg. Dth/Part. Saved =	17.09		
25	Escalation Rate =		4.28%					
26					22) Avg Non-Gas Fuel Units/Part. Saved =	0.00		
27	7) Non-Gas Fuel Cost ($/Fuel Unit) =		$0.00		22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00		
28	Escalation Rate =		2.16%					
29					23) Number of Participants =	27,614		
30	8) Non-Gas Fuel Loss Factor		0.00%					
31					24) Total Annual Dth Saved =	472,000		
32	9) Gas Environmental Damage Factor =		$0.3500					
33	Escalation Rate =		1.73%		25) Incentive/Participant =	$131		
34								
35	10) Non Gas Fuel Environmental Damage Factor =		$0.00					
36	Escalation Rate =		0.00%					
37								
38	11) Participant Discount Rate =		2.67%					
39								
40	12) Utility Discount Rate =		7.98%					
41								
42	13) Societal Discount Rate =		2.67%					
43								
44	14) General Input Data Year =		2012					
45								
46	15) Project Analysis Year 1 =		2016					
47	15a) Project Analysis Year 2 =		2014					
48	15c) Project Analysis Year 3 =		2015					
49								
50								
51								
52	**Cost Summary**	**2014**			**Test Results**	**NPV**	**B/C**	
53								
54	Utility Cost per Participant =	$326.41			**Ratepayer Impact Measure Test**	($75,087,743)	0.32	
55	Cost per Participant per Dth =	$42.15						
56					**Utility Cost Test**	$25,948,259	3.88	
57	Lifetime Energy Reduction (Dth)	6,608,005						
58					**Societal Test**	$34,206,355	3.10	
59	Societal Cost per Dth	$2.46						
60					**Participant Test**	$131,866,494	13.12	

Year	Energy Savings Achieved	Single-year Weather-Normalized sales	Savings as percent of same-year sales
2007	141,655	55,152,126	0.26%
2008	64,517	50,820,785	0.13%
2009	133,570	39,643,778	0.34%
2010	445,836	44,741,987	0.9965%
2011	457,748	45,142,079	1.0140%

3-year Weather-Normalized Sales Average:	43,175,948	From Table 1, 2015-2016 MERC CIP Extension Correction and Modificiation -- DOC DER Decisi
1.0% of Sales:	431,759	From Table 1, 2015-2016 MERC CIP Extension Correction and Modificiation

For CIP Budget, Energy Goal, and Estimated Benefits, include only those modifications that were required by Order or which the utility notified the OES that it planned to include in the incentive calculation upon approval. Include a summary of the modifications below.

Approved CIP Budget:	$11,280,537	From Table 6, Commissioner's 10/12/15 Decision approving Program Plan Extension
Approved CIP Energy Goal:	460,537	From Table 6, Commissioner's 10/12/15 Decision approving Program Plan Extension
Estimated Net Benefits at Approved Goal:	$22,865,068	From Compliance Filing bencost

Inputs:

Average Sales:	43,175,948	
1.0% Energy Savings:	431,759	
Historic Average Savings:	0.53%	(Average of 3 years of historic with min and max taken out)
Earning Threshold:	0.20%	plus one unit of energy
Earning Threshold in Energy Savings:	86,353	
Award zero point:	0.10%	
Award zero point in Energy Savings:	43,176	
Steps from zero point to 1.5%	14	
Size of steps in Energy Savings:	43,176	

Incentive Calibration:

Average Incentive per unit at 1.5%:	$9.00	Set by Commission in approval of incentive mechanism & calibration
Cap Level:	125%	of Calibration Point
Incentive Cap:	$6.875	per MCF
Energy savings at 1.5%:	647,639	
Targeted incentive at 1.5%:	$5,828,753	
Multiplier:	**1.29481%**	**Percent of Net Benefits received for every 0.1% of sales above zero point**

Estimated Incentive Levels:

Achievement Level (% of sales)	Energy Saved	Percent of Benefits Awarded	Estimated Net Benefits	Financial Incentive	Average Incentive per unit Saved
0.0%	0	0.00000%	$0	**$0**	0.000
0.1%	43,176	0.00000%	$2,143,630	**$0**	0.000
0.2%	86,352	0.00000%	$4,287,260	**$0**	0.000
0.3%	129,528	2.58962%	$6,430,890	**$166,536**	1.286
0.4%	172,704	3.88443%	$8,574,521	**$333,072**	1.929
0.5%	215,880	5.17925%	$10,718,151	**$555,119**	2.571
0.6%	259,056	6.47406%	$12,861,781	**$832,679**	3.214
0.7%	302,232	7.76887%	$15,005,411	**$1,165,751**	3.857
0.8%	345,408	9.06368%	$17,149,041	**$1,554,334**	4.500
0.9%	388,584	10.35849%	$19,292,671	**$1,998,430**	5.143
1.0%	431,759	11.65330%	$21,436,301	**$2,498,037**	5.786
1.1%	474,935	12.94811%	$23,579,931	**$3,053,156**	6.429
1.2%	518,111	14.24293%	$25,723,562	**$3,562,016**	6.875
1.3%	561,287	15.53774%	$27,867,192	**$3,858,850**	6.875
1.4%	604,463	16.83255%	$30,010,822	**$4,155,685**	6.875
1.5%	647,639	18.12736%	$32,154,452	**$4,452,520**	6.875
1.6%	690,815	19.42217%	$34,298,082	**$4,749,354**	6.875
1.7%	733,991	20.00000%	$36,441,712	**$5,046,189**	6.875
1.8%	777,167	20.00000%	$38,585,342	**$5,343,024**	6.875
1.9%	820,343	20.00000%	$40,728,972	**$5,639,858**	6.875
2.0%	863,519	20.00000%	$42,872,603	**$5,936,693**	6.875
2.1%	906,695	20.00000%	$45,016,233	**$6,233,527**	6.875
Energy Savings Achievement	472,000	12.86008%	$25,948,259	**$3,245,000**	6.875

Actual CIP Results

Spending:	$9,198,728	From Table B-2, MERC Status Report
Energy Saved:	472,000	From Table B-3, MERC Status Report
Net Benefits Achieved:	$25,948,259	2016 Bencost Model

Resulting Incentive:			
Steps above Zero Point:	9.93201		
Percent of Net Benefits Awarded:	12.86008%		
Financial Incentive Award:	$3,245,000		
Incentive per MCF	$6.8750		
Net Benefit after Incentive	$22,703,259		

ATTACHMENT C

MERC
CCRA Calculation
To Be Effective January 1, 2018

Forecasted beginning balance (January 1, 2018)	$ (3,461,377.07)
Proposed Expenditures (January 2018-December 2018)	$ 12,233,774.00
Forecasted 2016 Incentive (to be approved in 2017)	$ 3,245,000.00
Forecasted 2017 Incentive (to be approved in 2018)	$ 3,147,996.00
Less forecasted CCRC recovery (January 2018-December 2018)	$ (11,015,934.28)
Projected carrying charges for 2018	$ (71,761.45)
Forecasted December 2018 Balance	$ 4,077,697.20
Forecasted gas sales (January 2018-December 2018) Therms	398,118,333
CCRA=$/therm beginning January 1, 2018	$ 0.01024

ATTACHMENT D

Clean Tariff Sheet

CONSERVATION COST RECOVERY CHARGE AND ADJUSTMENT

All Classes MERC $0.01024

5. Exemption: For those customer accounts granted an exemption by the Commissioner of the Minnesota Department of Commerce (or successor agency) from Conservation Improvement Program (CIP) costs pursuant to Minnesota Statutes section 216B.241, the CCRC and CCRA shall not apply. Those customer accounts determined by the Commission to qualify as a Large Energy Facility Customers, shall receive a monthly exemption from conservation program charges pursuant to Minn. Stat.§ 216B.16, subd. 6b Energy Conservation Improvement. Upon exemption from conservation program charges, the Large Energy Facility customers can no longer participate in any utility's energy Conservation Improvement Program.

Under Minn. Stat. 216B.241, any customer account determined by the Commission of the Minnesota Department of Commerce to qualify as a large customer facility shall be exempt from CIP investment and expenditure requirements with respect to retail revenues attributable to the large customer facility. Customer accounts granted exemption by a decision of the Commissioner after the beginning of the calendar year shall be credited for any CIP collections billed after January first of the year following the Commissioner's decision. Upon exemption from the conservation program charges, no exempt customer facility may participate in a utility conservation improvement program unless the owner of the facility submits a filing with the Commissioner to withdraw its exemption.

Under Minn. Stat. 216B.241, any customer account that is not a large customer facility and that purchases or acquires natural gas from a public utility having fewer than 600,000 natural gas customers in Minnesota shall, upon a determination by the Commissioner of the Department of Commerce as qualifying for an opt out of the Conservation Improvement Program, be exempt from CIP investment and expenditure requirements with respect to retail revenues attributable to the commercial gas customers. Customer accounts granted exemption by a decision of the Commissioner after the beginning of the calendar year shall be credited for any CIP collections billed after January first of the year following the Commissioner's decision. Upon exemption from conservation program charges, the customers can no longer participate in any utility's energy Conservation Improvement Program unless the customer submits a filing with the Commissioner to withdraw its exemption.

6. Accounting Requirements: The Company is required to record all costs associated with the conservation program in a CIP Tracker Account. All revenues recovered through the CCRA are booked to the Tracker as an offset to expenses.

Redline Tariff Sheet

CONSERVATION COST RECOVERY CHARGE AND ADJUSTMENT

All Classes MERC $0.0110240750*

*Approved effective January 1, 2017

5. Exemption: For those customer accounts granted an exemption by the Commissioner of the Minnesota Department of Commerce (or successor agency) from Conservation Improvement Program (CIP) costs pursuant to Minnesota Statutes section 216B.241, the CCRC and CCRA shall not apply. Those customer accounts determined by the Commission to qualify as a Large Energy Facility Customers, shall receive a monthly exemption from conservation program charges pursuant to Minn. Stat.§ 216B.16, subd. 6b Energy Conservation Improvement. Upon exemption from conservation program charges, the Large Energy Facility customers can no longer participate in any utility's energy Conservation Improvement Program.

Under Minn. Stat. 216B.241, any customer account determined by the Commission of the Minnesota Department of Commerce to qualify as a large customer facility shall be exempt from CIP investment and expenditure requirements with respect to retail revenues attributable to the large customer facility. Customer accounts granted exemption by a decision of the Commissioner after the beginning of the calendar year shall be credited for any CIP collections billed after January first of the year following the Commissioner's decision. Upon exemption from the conservation program charges, no exempt customer facility may participate in a utility conservation improvement program unless the owner of the facility submits a filing with the Commissioner to withdraw its exemption.

Under Minn. Stat. 216B.241, any customer account that is not a large customer facility and that purchases or acquires natural gas from a public utility having fewer than 600,000 natural gas customers in Minnesota shall, upon a determination by the Commissioner of the Department of Commerce as qualifying for an opt out of the Conservation Improvement Program, be exempt from CIP investment and expenditure requirements with respect to retail revenues attributable to the commercial gas customers. Customer accounts granted exemption by a decision of the Commissioner after the beginning of the calendar year shall be credited for any CIP collections billed after January first of the year following the Commissioner's decision. Upon exemption from conservation program charges, the customers can no longer participate in any utility's energy Conservation Improvement Program unless the customer submits a filing with the Commissioner to withdraw its exemption.

6. Accounting Requirements: The Company is required to record all costs associated with the conservation program in a CIP Tracker Account. All revenues recovered through the CCRA are booked to the Tracker as an offset to expenses.

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of the 2016 Conservation Improvement Program Tracker Account, Demand-Side Management Financial Incentive, and Conservation Cost Recovery Adjustment Factor

Docket No. G011/M-17-___

CERTIFICATE OF SERVICE

I, Kristin M. Stastny, hereby certify that on the 1st of May, 2017, on behalf of Minnesota Energy Resources Corporation, I electronically filed a true and correct copy of the enclosed compliance filing on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

Dated this 1st of May, 2017.

/s/ Kristin M. Stastny
Kristin M. Stastny

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Conservation Improvement Program (CIP)
BENCOST FOR GAS CIPS-- Cost-Effectiveness Analysis

Company: Minnesota Energy Resources

Global Inputs

Input Data			Escalation Rate
1) Retail Rate ($/Dth) =	$16.06	Residential	4.28%
	$15.82	Commercial	
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00		2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =			
3) Commodity Cost ($/Dth) =	$4.34		4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53		4.28%
5) Peak Reduction Factor =	1.00%		
6) Variable O&M ($/Dth) =	$0.03		4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00		2.16%
8) Non-Gas Fuel Loss Factor	0.00%		
9) Gas Environmental Damage Factor =	$0.3500		1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00		0.00%
11) Participant Discount Rate =	2.67%	Residential	
	7.98%	Commercial	
12) Utility Discount Rate =	7.98%		
13) Societal Discount Rate =	2.67%		
14) General Input Data Year =	2012		
15) Project Analysis Year =	2016		

	A	B	C	D	E	F	G	H
1	3.1							
2	Conservation Improvement Program (CIP)			BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis				
3				Approved by Minnesota Department of Commerce, January 26, 2006				
4	Company: Minnesota Energy Resources							
5	Project: TOTAL CIP - 2016							
6				R				
7	Input Data					2016 Actual		
8								
9	1) Retail Rate ($/Dth) =		$16.06		16) Utility Project Costs			
10	Escalation Rate =		4.28%		16a) Administrative & Operating Costs =	$5,387,527		
11					16b) Incentive Costs =	$3,626,067		
12	2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =		$0.00		16c) Total Utility Project Costs =	$9,013,595		
13	Escalation Rate =		2.16%					
14	Non-Gas Fuel Units (ie. kWh,Gallons, etc) =				17) Direct Participant Costs ($/Part.) =	$394		
15								
16	3) Commodity Cost ($/Dth) =		$4.34		18) Participant Non-Energy Costs (Annual $/Part.) =	$0		
17	Escalation Rate =		4.28%		Escalation Rate =	0.00%		
18								
19	4) Demand Cost ($/Unit/Yr) =		$118.53		19) Participant Non-Energy Savings (Annual $/Part) =	$0		
20	Escalation Rate =		4.28%		Escalation Rate =	0.00%		
21								
22	5) Peak Reduction Factor =		1.00%		20) Project Life (Years) =	13.9		
23								
24	6) Variable O&M ($/Dth) =		$0.03		21) Avg. Dth/Part. Saved =	17.09		
25	Escalation Rate =		4.28%					
26					22) Avg Non-Gas Fuel Units/Part. Saved =	0.00		
27	7) Non-Gas Fuel Cost ($/Fuel Unit) =		$0.00		22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00		
28	Escalation Rate =		2.16%					
29					23) Number of Participants =	27,614		
30	8) Non-Gas Fuel Loss Factor		0.00%					
31					24) Total Annual Dth Saved =	472,000		
32	9) Gas Environmental Damage Factor =		$0.3500					
33	Escalation Rate =		1.73%		25) Incentive/Participant =	$131		
34								
35	10) Non Gas Fuel Environmental Damage Factor =		$0.00					
36	Escalation Rate =		0.00%					
37								
38	11) Participant Discount Rate =		2.67%					
39								
40	12) Utility Discount Rate =		7.98%					
41								
42	13) Societal Discount Rate =		2.67%					
43								
44	14) General Input Data Year =		2012					
45								
46	15) Project Analysis Year 1 =		2016					
47	15a) Project Analysis Year 2 =		2014					
48	15c) Project Analysis Year 3 =		2015					
49								
50								
51								
52	Cost Summary	2014			Test Results	NPV	B/C	
53								
54	Utility Cost per Participant =	$326.41			Ratepayer Impact Measure Test	($75,087,743)	0.32	
55	Cost per Participant per Dth =	$42.15						
56					Utility Cost Test	$25,948,259	3.88	
57	Lifetime Energy Reduction (Dth)	6,608,005						
58					Societal Test	$34,206,355	3.10	
59	Societal Cost per Dth	$2.46						
60					Participant Test	$131,866,494	13.12	

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: TOTAL LOW INCOME

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$1,119,228
16b) Incentive Costs =	$0
16c) Total Utility Project Costs =	$ 1,119,228
17) Direct Participant Costs ($/Part.) =	$0
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	11.9
21) Avg. Dth/Part. Saved =	18.72
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	448
24) Total Annual Dth Saved =	8,388
25) Incentive/Participant =	$0

Cost Summary	2014
Utility Cost per Participant =	$2,498.28
Cost per Participant per Dth =	$133.44
Lifetime Energy Reduction (Dth)	100,650
Societal Cost per Dth	$11.12

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($2,158,620)	0.20
Utility Cost Test	($569,254)	0.49
Societal Test	($361,775)	0.68
Participant Test	$2,085,249	n/a

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: TOTAL RESIDENTIAL

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$1,934,625
16b) Incentive Costs =	$2,486,416
16c) Total Utility Project Costs =	$ 4,421,041
17) Direct Participant Costs ($/Part.) =	$442
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	18.2
21) Avg. Dth/Part. Saved =	10.12
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	20,942
24) Total Annual Dth Saved =	211,918
25) Incentive/Participant =	$119

Cost Summary	2014
Utility Cost per Participant =	$211.11
Cost per Participant per Dth =	$64.49
Lifetime Energy Reduction (Dth)	4,026,438
Societal Cost per Dth	$2.78

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($41,629,002)	0.32
Utility Cost Test	$15,266,830	4.45
Societal Test	$20,758,592	2.86
Participant Test	$81,520,791	9.82

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: TOTAL COMMERCIAL / INDUSTRIAL

C

Input Data	
1) Retail Rate ($/Dth) =	$15.82
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	7.98%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$1,140,843
16b) Incentive Costs =	$1,139,652
16c) Total Utility Project Costs =	$ 2,280,495
17) Direct Participant Costs ($/Part.) =	$263
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	10.4
21) Avg. Dth/Part. Saved =	40.44
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	6,224
24) Total Annual Dth Saved =	251,695
25) Incentive/Participant =	$183

Cost Summary	2014
Utility Cost per Participant =	$366.40
Cost per Participant per Dth =	$15.56
Lifetime Energy Reduction (Dth)	2,768,645
Societal Cost per Dth	$1.00

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($30,676,553)	0.33
Utility Cost Test	$13,096,103	6.74
Societal Test	$17,904,712	7.45
Participant Test	$43,276,140	27.45

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: LIW

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$293,083
16b) Incentive Costs =	$0
16c) Total Utility Project Costs =	$293,083
17) Direct Participant Costs ($/Part.) =	$0
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	19.9
21) Avg. Dth/Part. Saved =	19.01
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	109
24) Total Annual Dth Saved =	2,072
25) Incentive/Participant =	$0

Cost Summary	2014
Utility Cost per Participant =	$2,688.83
Cost per Participant per Dth =	$141.46
Lifetime Energy Reduction (Dth)	41,438
Societal Cost per Dth	$7.07

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($670,128)	0.23
Utility Cost Test	($93,576)	0.68
Societal Test	$38,134	1.13
Participant Test	$915,990	#DIV/0!

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: 4U2

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$826,145
16b) Incentive Costs =	$0
16c) Total Utility Project Costs =	$826,145
17) Direct Participant Costs ($/Part.) =	$0
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	9.3
21) Avg. Dth/Part. Saved =	18.63
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	339
24) Total Annual Dth Saved =	6,316
25) Incentive/Participant =	$0

Cost Summary	2014
Utility Cost per Participant =	$2,437.01
Cost per Participant per Dth =	$130.81
Lifetime Energy Reduction (Dth)	63,156
Societal Cost per Dth	$13.08

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($1,499,986)	0.19
Utility Cost Test	($469,595)	0.43
Societal Test	($357,840)	0.57
Participant Test	$1,287,684	#DIV/0!

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: Res Rebates

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$589,529
16b) Incentive Costs =	$2,003,440
16c) Total Utility Project Costs =	$2,592,969
17) Direct Participant Costs ($/Part.) =	$501
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	17.5
21) Avg. Dth/Part. Saved =	9.51
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	16,180
24) Total Annual Dth Saved =	153,893
25) Incentive/Participant =	$124

Cost Summary	2014
Utility Cost per Participant =	$160.26
Cost per Participant per Dth =	$69.54
Lifetime Energy Reduction (Dth)	2,770,068
Societal Cost per Dth	$3.14

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($28,592,660)	0.32
Utility Cost Test	$11,164,264	5.31
Societal Test	$13,108,800	2.51
Participant Test	$54,136,022	7.68

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: Home En Exc

R

Input Data	
1) Retail Rate ($/Dth) =	$16.06
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	2.67%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$1,150,059
16b) Incentive Costs =	$482,976
16c) Total Utility Project Costs =	$1,633,035
17) Direct Participant Costs ($/Part.) =	$980
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	20.0
21) Avg. Dth/Part. Saved =	48.22
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	1,161
24) Total Annual Dth Saved =	55,987
25) Incentive/Participant =	$416

Cost Summary	2014
Utility Cost per Participant =	$1,406.58
Cost per Participant per Dth =	$49.48
Lifetime Energy Reduction (Dth)	1,119,736
Societal Cost per Dth	$2.04

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($11,821,543)	0.31
Utility Cost Test	$3,758,017	3.30
Societal Test	$6,662,641	3.91
Participant Test	$24,097,391	22.19

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: CI Rebate

C

Input Data	
1) Retail Rate ($/Dth) =	$15.82
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	7.98%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$921,743
16b) Incentive Costs =	$1,075,591
16c) Total Utility Project Costs =	$1,997,334
17) Direct Participant Costs ($/Part.) =	$1,714
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	10.7
21) Avg. Dth/Part. Saved =	271.18
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	872
24) Total Annual Dth Saved =	236,470
25) Incentive/Participant =	$1,233

Cost Summary	2014
Utility Cost per Participant =	$2,290.52
Cost per Participant per Dth =	$14.77
Lifetime Energy Reduction (Dth)	2,601,169
Societal Cost per Dth	$0.93

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($28,675,702)	0.34
Utility Cost Test	$12,449,126	7.23
Societal Test	$17,014,720	8.04
Participant Test	$40,706,206	28.24

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: Small Business

C

Input Data	
1) Retail Rate ($/Dth) =	$15.82
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	7.98%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$85,642
16b) Incentive Costs =	$8,962
16c) Total Utility Project Costs =	$94,603
17) Direct Participant Costs ($/Part.) =	$132
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	10.4
21) Avg. Dth/Part. Saved =	10.21
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	317
24) Total Annual Dth Saved =	3,235
25) Incentive/Participant =	$28

Cost Summary	2014
Utility Cost per Participant =	$298.43
Cost per Participant per Dth =	$42.16
Lifetime Energy Reduction (Dth)	35,589
Societal Cost per Dth	$3.58

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($459,613)	0.30
Utility Cost Test	$103,051	2.09
Societal Test	$138,406	2.09
Participant Test	$529,826	13.68

Conservation Improvement Program (CIP)

BENEFIT COST FOR GAS CIPS-- Cost-Effectiveness Analysis
Approved by Minnesota Department of Commerce, January 26, 2006

Company: Minnesota Energy Resources
Project: Multifamily

C

Input Data	
1) Retail Rate ($/Dth) =	$15.82
Escalation Rate =	4.28%
2) Non-Gas Fuel Retail Rate ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
Non-Gas Fuel Units (ie. kWh,Gallons, etc) =	
3) Commodity Cost ($/Dth) =	$4.34
Escalation Rate =	4.28%
4) Demand Cost ($/Unit/Yr) =	$118.53
Escalation Rate =	4.28%
5) Peak Reduction Factor =	1.00%
6) Variable O&M ($/Dth) =	$0.03
Escalation Rate =	4.28%
7) Non-Gas Fuel Cost ($/Fuel Unit) =	$0.00
Escalation Rate =	2.16%
8) Non-Gas Fuel Loss Factor	0.00%
9) Gas Environmental Damage Factor =	$0.3500
Escalation Rate =	1.73%
10) Non Gas Fuel Environmental Damage Factor =	$0.00
Escalation Rate =	0.00%
11) Participant Discount Rate =	7.98%
12) Utility Discount Rate =	7.98%
13) Societal Discount Rate =	2.67%
14) General Input Data Year =	2012
15) Project Analysis Year 1 =	2016
15a) Project Analysis Year 2 =	2014
15c) Project Analysis Year 3 =	2015

	2016 Actual
16) Utility Project Costs	
16a) Administrative & Operating Costs =	$125,532
16b) Incentive Costs =	$21,199
16c) Total Utility Project Costs =	$146,731
17) Direct Participant Costs ($/Part.) =	$20
18) Participant Non-Energy Costs (Annual $/Part.) =	$0
Escalation Rate =	0.00%
19) Participant Non-Energy Savings (Annual $/Part) =	$0
Escalation Rate =	0.00%
20) Project Life (Years) =	5.9
21) Avg. Dth/Part. Saved =	1.72
22) Avg Non-Gas Fuel Units/Part. Saved =	0.00
22a) Avg Additional Non-Gas Fuel Units/ Part. Used =	0.00
23) Number of Participants =	4,978
24) Total Annual Dth Saved =	8,578
25) Incentive/Participant =	$4

Cost Summary	2014
Utility Cost per Participant =	$29.48
Cost per Participant per Dth =	$28.78
Lifetime Energy Reduction (Dth)	51,467
Societal Cost per Dth	$4.39

Test Results	NPV	B/C
Ratepayer Impact Measure Test	($720,197)	0.30
Utility Cost Test	$163,803	2.12
Societal Test	$144,927	1.64
Participant Test	$805,045	9.04

Year	Energy Savings Achieved	Single-year Weather-Normalized sales	Savings as percent of same-year sales
2007	141,655	55,152,126	0.26%
2008	64,517	50,820,785	0.13%
2009	133,570	39,643,778	0.34%
2010	445,836	44,741,987	0.9965%
2011	457,748	45,142,079	1.0140%

3-year Weather-Normalized Sales Average:	43,175,948	From Table 1, 2015-2016 MERC CIP Extension Correction and Modificiation -- DOC DER Decision
1.0% of Sales:	431,759	From Table 1, 2015-2016 MERC CIP Extension Correction and Modificiation

For CIP Budget, Energy Goal, and Estimated Benefits, include only those modifications that were required by Order or which the utility notified the OES that it planned to include in the incentive calculation upon approval. Include a summary of the modifications below.

Approved CIP Budget:	$11,280,537	From Table 6, Commissioner's 10/12/15 Decision approving Program Plan Extension
Approved CIP Energy Goal:	460,537	From Table 6, Commissioner's 10/12/15 Decision approving Program Plan Extension
Estimated Net Benefits at Approved Goal:	$22,865,068	From Compliance Filing bencost

Inputs:

Average Sales:	43,175,948	
1.0% Energy Savings:	431,759	
Historic Average Savings:	0.53%	(Average of 3 years of historic with min and max taken out)
Earning Threshold:	0.20%	plus one unit of energy
Earning Threshold in Energy Savings:	86,353	
Award zero point:	0.10%	
Award zero point in Energy Savings:	43,176	
Steps from zero point to 1.5%	14	
Size of steps in Energy Savings:	43,176	

Incentive Calibration:

Average Incentive per unit at 1.5%:	$9.00	Set by Commission in approval of incentive mechanism & calibration
Cap Level:	125%	of Calibration Point
Incentive Cap:	$6.875	per MCF
Energy savings at 1.5%:	647,639	
Targeted incentive at 1.5%:	$5,828,753	
Multiplier:	**1.29481%**	**Percent of Net Benefits received for every 0.1% of sales above zero point**

Estimated Incentive Levels:

Achievement Level (% of sales)	Energy Saved	Percent of Benefits Awarded	Estimated Net Benefits	Financial Incentive	Average Incentive per unit Saved
0.0%	0	0.00000%	$0	**$0**	0.000
0.1%	43,176	0.00000%	$2,143,630	**$0**	0.000
0.2%	86,352	0.00000%	$4,287,260	**$0**	0.000
0.3%	129,528	2.58962%	$6,430,890	**$166,536**	1.286
0.4%	172,704	3.88443%	$8,574,521	**$333,072**	1.929
0.5%	215,880	5.17925%	$10,718,151	**$555,119**	2.571
0.6%	259,056	6.47406%	$12,861,781	**$832,679**	3.214
0.7%	302,232	7.76887%	$15,005,411	**$1,165,751**	3.857
0.8%	345,408	9.06368%	$17,149,041	**$1,554,334**	4.500
0.9%	388,584	10.35849%	$19,292,671	**$1,998,430**	5.143
1.0%	431,759	11.65330%	$21,436,301	**$2,498,037**	5.786
1.1%	474,935	12.94811%	$23,579,931	**$3,053,156**	6.429
1.2%	518,111	14.24293%	$25,723,562	**$3,562,016**	6.875
1.3%	561,287	15.53774%	$27,867,192	**$3,858,850**	6.875
1.4%	604,463	16.83255%	$30,010,822	**$4,155,685**	6.875
1.5%	647,639	18.12736%	$32,154,452	**$4,452,520**	6.875
1.6%	690,815	19.42217%	$34,298,082	**$4,749,354**	6.875
1.7%	733,991	20.00000%	$36,441,712	**$5,046,189**	6.875
1.8%	777,167	20.00000%	$38,585,342	**$5,343,024**	6.875
1.9%	820,343	20.00000%	$40,728,972	**$5,639,858**	6.875
2.0%	863,519	20.00000%	$42,872,603	**$5,936,693**	6.875
2.1%	906,695	20.00000%	$45,016,233	**$6,233,527**	6.875
Energy Savings Achievement	472,000	12.86008%	$25,948,259	**$3,245,000**	6.875

Actual CIP Results

Spending:	$9,198,728	From Table B-2, MERC Status Report
Energy Saved:	472,000	From Table B-3, MERC Status Report
Net Benefits Achieved:	$25,948,259	2016 Bencost Model

Resulting Incentive:			
Steps above Zero Point:	9.93201		
Percent of Net Benefits Awarded:	12.86008%		
Financial Incentive Award:	$3,245,000		
Incentive per MCF	$6.8750		
Net Benefit after Incentive	$22,703,259		