

Exhibit No.:
Issues: Demand-Side Programs
Witness: John A. Rogers
Sponsoring Party: MO PSC Staff
Type of Exhibit: Rebuttal
To Supplemental Testimony
File No.: EO-2015-0055
Date Testimony Prepared: July 15, 2015

MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

JOHN A. ROGERS

REBUTTAL TO SUPPLEMENTAL TESTIMONY

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

FILE NO. EO-2015-0055

*Jefferson City, Missouri
July 2015*

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company)
d/b/a Ameren Missouri's 2nd Filing to)
Implement Regulatory Changes in) Case No. EO-2015-0055
Furtherance of Energy Efficiency as allowed)
by MEEIA)

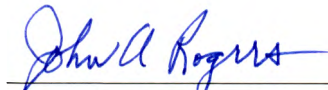
AFFIDAVIT OF JOHN A. ROGERS

State of Missouri)
) ss.
County of Cole)

AFFIDAVIT

COMES NOW John A. Rogers and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Rebuttal to Supplemental Testimony and that the same is true and correct according to his best knowledge and belief.

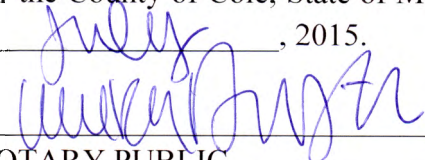
Further the Affiant sayeth not.



John A. Rogers

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of _____, 2015.



NOTARY PUBLIC



1 support for Commission approval of the June 30, 2015 Non-Unanimous Stipulation and
2 Agreement¹ (“Utility Stipulation”). My rebuttal to supplemental testimony will:

- 3 1. Present Staff’s analysis of the customers’ benefits and customers’ costs -
4 including the costs for the throughput disincentive and performance incentive -
5 which are expected from implementation of the energy efficiency programs
6 and the demand-side programs investment mechanism (“DSIM”) contained in
7 the Utility Stipulation;²
- 8 2. Comment on why the Company’s proposed portfolio of energy efficiency
9 programs and DSIM will likely result in very little, if any, net benefits for the
10 vast majority of customers;
- 11 3. Respond to the Company’s commitment to meet with the signatories to the
12 Utility Stipulation during the first four months of 2016 to review potential
13 additional energy efficiency opportunities to determine if it is possible to
14 achieve savings above the targeted level in 2017 and 2018; and
- 15 4. Provide Staff’s response to the proposed combined heat and power (“CHP”)
16 measure in the Utility Stipulation.

¹ Non-Unanimous Stipulation and Agreement with the following signatories: Ameren Missouri, Missouri Department of Economic Development – Division of Energy, Natural Resource Defense Council, Kansas City Power and Light Company, KCP&L Greater Missouri Operations Company, and United for Missouri.

² While Ameren Missouri is not required to provide a similar analysis, Staff believes Staff’s analysis is instructive for the Commission during its consideration of the issues in this case.

1 **CUSTOMERS' EXPECTED BENEFITS AND COSTS - INCLUDING THE COSTS**
2 **FOR THE THROUGHPUT DISINCENTIVE AND PERFORMANCE INCENTIVE -**
3 **FROM PROGRAMS AND DSIM IN UTILITY STIPULATION**

4 Q. In your opinion, in the Utility Stipulation, does Ameren Missouri provide all
5 the quantitative information and analysis the Commission needs when it considers whether or
6 not to approve the proposed demand-side programs (“Utility Portfolio”)?

7 A. No, it does not. In fact, it does not appear it was Mr. Laurent’s intention to
8 present a complete analysis since his supplemental testimony states: “The purpose of my
9 testimony is to provide an overview of the additional savings targets, budget, programs and
10 enhancements to the original MEEIA 2016-18 Plan, ...”³

11 Q. What information is available for Commission consideration of the Utility
12 Stipulation demand-side programs?

13 A. Table 1 and Table 2 of the Utility Stipulation present the demand-side
14 programs which Ameren Missouri is requesting the Commission approve.

15 While the tables provide the energy savings, proposed budget, and total resource cost
16 (“TRC”) for each program, along with the total residential programs, total business programs
17 and total utility portfolio, neither the tables nor the supporting supplemental testimony
18 provide a complete analysis of the Customers’ expected benefits and costs - including the
19 costs for the throughput disincentive and performance incentive – which are expected as a
20 result of the energy efficiency programs and the DSIM in the Utility Stipulation.

21 Q. Has Staff performed an analysis of customers’ benefits and customers’ costs -
22 including the costs for the throughput disincentive and performance incentive - which are

³ Laurent supplemental testimony at page 2, lines 3 – 5.

1 | expected from implementation of the Utility Portfolio and DSIM in the Utility Stipulation
2 | since Ameren Missouri did not present such analysis in its testimony?

3 | A. Yes. Schedule JAR-1 contains the results of Staff’s analysis. Please note that
4 | all dollars in Schedule JAR-1 are discounted dollars using Ameren Missouri’s weighted
5 | average cost of capital of 6.46%.

6 | Q. Please discuss the process you used to perform the analysis contained in
7 | Schedule JAR-1.

8 | A. Schedule JAR-1 has four separate sections which present the energy savings,
9 | demand savings, costs and benefits for the entire portfolio, residential programs and business
10 | programs for Commission-approved Cycle 1, the Cycle 2 application, and the Utility
11 | Stipulation including:

- 12 | 1. “Benefits and Costs Summary” reflects a summary of data Staff obtained from
13 | Ameren Missouri’s filed documents and work papers, except for two
14 | exceptions in the Utility Stipulation column. Data is not available for the
15 | Utility Stipulation throughput disincentive or the 100% performance incentive
16 | amounts so Staff has estimated these amounts;⁴
- 17 | 2. “Customers as a Whole” represents all customers, i.e., residential customers
18 | and business customers combined, which is normally the only way these three
19 | market segments are analyzed;

⁴ Each Utility Stipulation Throughput Disincentive amount and 100% Performance Incentive amount is estimated to be the Cycle 2 amount factored up or down based upon the relative “deemed” Energy Savings Target (GWh) amounts. For example: Utility Stipulation Portfolio Throughput Disincentive is \$60 Million = \$44 Million X (584 GWh / 426 GWh).

1 3. “Non-Participating Customers” represents all customers who do not participate
2 directly - and in a meaningful way - in one or more programs;⁵ and

3 4. “Participating Customers” represents all customers who participate directly in
4 one or more programs, which in Staff’s analysis is the same as the participant
5 cost test⁶ (“PCT”).

6 Q. What do the letters and equations represent in the left hand column on Table 1?

7 A. But for the two exceptions described in my last answer, the individual letters
8 represent values Staff obtained from Ameren Missouri’s filed documents and work papers for
9 Commission-approved Cycle 1, the Cycle 2 application, and the Utility Stipulation. The
10 equations include the calculation of amounts related to customers’ benefits and costs which
11 are not available in the filed documents and work papers.

12 Q. In your opinion, what is the most significant data from Staff’s analysis in
13 Schedule JAR-1?

14 A. The most significant data from Schedule JAR-1 is presented in Schedule JAR-
15 2, which contains graphical representations of the TRC, utility cost test (“UCT”), and benefit
16 cost ratios for Cycle 1, the Cycle 2 application and the Utility Stipulation.

17 At a high level:

18 1. The TRC and UCT ratios⁷ are significantly greater for Cycle 1 when compared
19 to Cycle 2 which is primarily due to the much lower avoided costs of energy

⁵ Because residential customers who are required to pay the Energy Efficiency Investment Charge (customers that are not qualified low income customers, which are exempt from paying the charge) will pay on average \$6 per month and \$216 total during the 36 months of Cycle 2, these customers will likely have to participate in more than just the residential lighting program to receive overall net benefits.

⁶ Line j in Schedule JAR-1 provides the equations for calculating the PCT. 4 CSR 240-3.164(Q) provides a general definition of the participant test.

1 and demand used to value benefits from energy and demand savings for Cycle
2 2;⁸

3 2. Benefit cost ratios for participants have increased for Cycle 2 relative to Cycle
4 1 and for the Utility Stipulation relative to Cycle 2; and

5 3. Benefit cost ratios for customers as a whole and for customers who are non-
6 participants have decreased significantly for Cycle 2 relative to Cycle 1 and
7 have decreased for the Utility Stipulation relative to Cycle 2.

8 Q. What conclusion should the Commission draw from the various benefit cost
9 ratios you present above?

10 A. The benefit cost ratios demonstrate that the Utility Stipulation provides for
11 even higher costs and relatively lower net benefits for the customers as a whole and for non-
12 participating customers than the Cycle 2 application, which is a concern.

13 **VERY LITTLE, IF ANY, NET BENEFITS ARE EXPECTED FOR THE VAST**
14 **MAJORITY OF CUSTOMERS**

15 Q. Please respond to Mr. Laurent's statement: "Ameren Missouri recognizes the
16 importance of being a good steward of the money that customers entrust to us to manage these
17 programs."⁹

18 A. Mr. Laurent's Table 2 provides only the TRC values for programs in the
19 Utility Stipulation. The TRCs for residential, business and portfolio levels are 1.31, 1.62, and
20 1.50, respectively. The TRCs in Table 2 suggest that if Ameren Missouri is successful in
21 delivering all program services as planned and all deemed values are realized, then all

⁷ Lines i and h in Schedule JAR-1 provide the equations for calculating the TRC and UCT, respectively, for Cycle 1, Cycle 2 and the Utility Stipulation. The complete definitions for TRC and UCT are contained in 4 CSR 240-3.164(1)(X) and 4 CSR 240-3.164(1)(Y), respectively.

⁸ Rogers surrebuttal testimony Schedule JAR-S4.

⁹ Laurent supplemental testimony at page 7, lines 1 – 2.

1 customers will benefit from the programs for which they pay. However, when factoring in the
2 costs for the throughput disincentive and 100% performance incentive, Staff's analysis
3 suggests that the majority of Ameren Missouri customers will likely receive very little, if any,
4 overall net benefits from the programs and the DSIM in the Utility Stipulation.

5 Q. Please explain.

6 A. Approximately 87% of Ameren Missouri's customers are residential
7 customers.¹⁰ Schedule JAR-1 estimates that net benefits and benefit cost ratios are expected
8 to be:

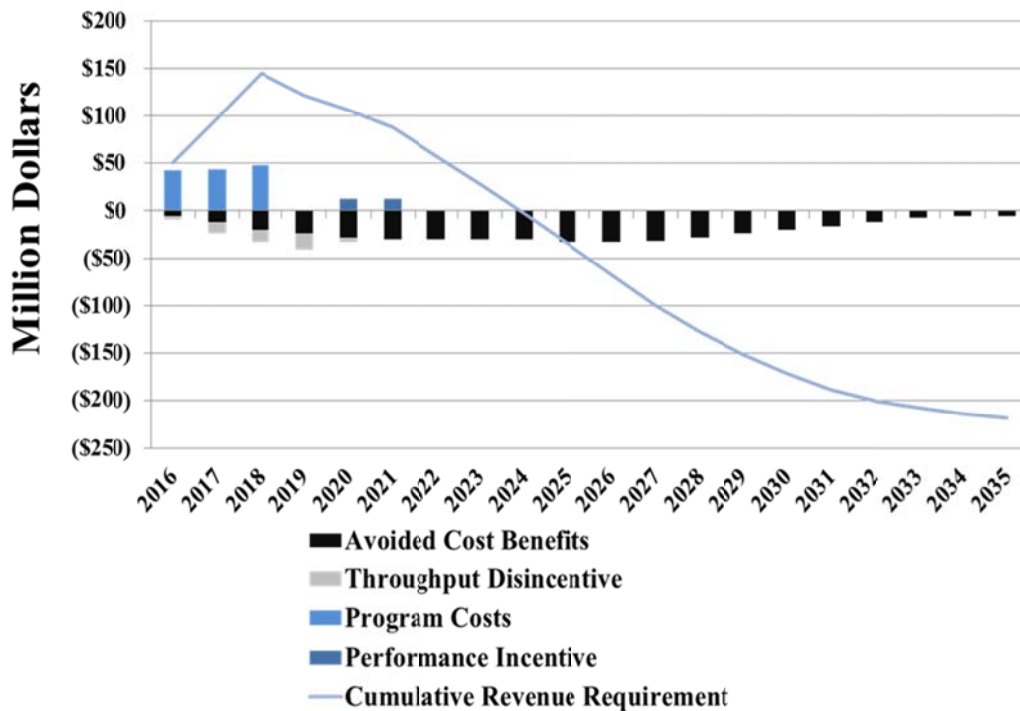
- 9 • \$30 million and 1.34, respectively, for residential customers as a whole;
- 10 • \$7 million and 1.06 for residential customers who are not expected to
11 participate directly in programs, either because they have no awareness of the
12 programs, have no interest in participating, have no need to participate, or they
13 do not have the financial means to participate in a meaningful way by making
14 a significant investment in energy efficiency measures; and
- 15 • \$217 million and 5.84 for customers who participate directly in programs.

16 Staff's analysis estimates that residential customers who are non-participants will pay
17 \$112 million with the expectation that they will receive benefits of \$119 million as a result of
18 the programs and DSIM in the Utility Stipulation. Thus, as demonstrated in Schedule JAR-1,
19 the expected net benefits non-participating residential customers are expected to receive are
20 only worth an estimated \$7 million and the benefit cost ratio is only 1.06.

21 Q. Is it a certainty that \$7 million of net benefits will be realized by non-
22 participating residential customers?

¹⁰ Page 2 of Ameren Missouri's 2014 Annual Report (Tracking No. BMAR-2015-1678) specifies that 1,043,038 of Ameren Missouri's 1,202,283 total customers are residential customers. $1,043,038/1,202,283 = 0.868$.

11 A. No. There is uncertainty and risk associated with expected customer benefits.
 12 Because expected benefits occur over the expected life of each measure (up to 20 years) and
 13 are based upon "deemed" energy and demand savings, which is a static baseline for
 14 determination of annual energy and demand savings from each energy efficiency measure,
 15 and "deemed" avoided costs for each energy efficiency measure, there are no guarantees on
 16 the return of net benefits. On the other hand, customers will certainly pay all program costs
 17 "contemporaneously" in years 1, 2 and 3 and will certainly pay any performance incentive
 18 award in years 5 and 6. The overall timing of customers' costs and benefits for all customers
 19 and all programs is illustrated in the following chart¹¹ from Ameren Missouri's Cycle 2
 20 application.



12

¹¹ Data from Figure 3.9 on page 55 of the Cycle 2 Plan. All costs, benefits and cumulative revenue requirements in this chart are in millions of nominal dollars.

1 Q. Please provide any additional comments you would like the Commission to
2 consider regarding Staff's analysis in Schedule JAR-1.

3 A. Using the information and data, or lack thereof, in Ameren's supplemental
4 testimony, filed documents and work papers, only the benefits and costs for customers as a
5 whole and for customers who are participants can be derived with accuracy. The benefits and
6 costs for customers who do not participate in a meaningful way (non-participants) are
7 calculated based upon the simplified assumptions which allocate all of the programs' costs
8 and benefits, all of the throughput disincentive costs, and all of the 100% performance
9 incentive costs to the non-participants. Nevertheless, it is instructive for the Commission to
10 consider the analysis in Schedule JAR-1 and its resulting conclusion that there exists a
11 significant possibility – if not a probability – that little to no net benefits will be realized by
12 the majority of residential customers who pay for programs.

13 **ADDITIONAL ENERGY EFFICIENCY OPPORTUNITIES TO DETERMINE IF IT**
14 **IS POSSIBLE TO ACHIEVE SAVINGS ABOVE THE TARGETED LEVEL IN 2017**
15 **AND 2018**

16 Q. Please respond to Mr. Laurent's testimony at page 4, lines 6 - 13:

17 Ameren Missouri has agreed to meet with the signatories to the Stipulation
18 during the first four months of 2016 to review potential additional energy
19 efficiency opportunities to determine if it is possible to achieve savings above
20 the targeted level in 2017 and 2018. Ameren Missouri *cannot commit* to a
21 higher target level than the level set in the Stipulation, but it is certainly willing
22 to continue to discuss this issue with the signatories to the Stipulation and
23 determine if there are additional cost-effective measures or program changes
24 which could be adopted that would result in the achievement of additional
25 MWh savings or cost reductions.

26 [Emphasis added]

27 A. Based upon the analysis presented in this testimony, it is Staff's opinion that a
28
29 lack of commitment by Ameren Missouri largely mitigates any assurances that the majority of
30

1 its customers will receive overall net benefits from the Utility Stipulation’s programs for
2 2016, 2017 and 2018.

3 **COMBINED HEAT AND POWER**

4 Q. Please respond to Mr. Laurent’s testimony at page 6, lines 3 – 5: “Based on
5 input from the Division of Energy, the signatories to the stipulation are proposing to include
6 Combined Heat and Power (CHP) as an eligible measure under the business custom
7 program.”

8 A. In Staff’s opinion, it is questionable whether individual CHP projects can
9 qualify as demand-side programs under MEEIA.¹² However, assuming individual CHP
10 projects can qualify as demand-side programs under MEEIA, care must be taken before
11 qualifying the projects under MEEIA and the Commission’s MEEIA rules.¹³ Sections
12 393.1075. 2. (3) and 4 CSR 240-20.093 (1) (L) define a demand-side program as ‘... any
13 program conducted by the utility to modify the net consumption of electricity on the retail
14 customer’s side of the meter including, but not limited to, energy efficiency measures, load
15 management, demand response, and interruptible or curtailable load.’ Section 393.1075.2.(4)
16 and 4 CSR 240-20.093(1)(U) define energy efficiency as “measures that reduce the amount of
17 electricity required to achieve a given end use.” Commission rule 4 CSR 240-20.093(1)(K)
18 defines demand response as “... measures that decrease peak demand or shift demand to off-
19 peak periods.” Under MEEIA rules, only the actual customer load curtailment amount would
20 meet the requirements to qualify for an approved MEEIA demand response program.
21 Therefore, for a CHP application, under the MEEIA rules, only the difference between the

¹² Section 393.1075,

¹³ The Commission’s rules promulgated as a result of the Missouri Energy Efficiency Investment Act of 2009 (“MEEIA”) (Section 393.1075, RSMo, Supp. 2013) include Rules 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094, which were all first effective on May 30, 2011.

1 actual electrical consumption on the customer's side of the meter before and after the
2 installation of a CHP system would be considered. Commission rule 4 CSR 240-3.164
3 identifies all of the demand-side program filing and submittal requirements for a program to
4 be an approved as a MEEIA demand-side program. More specifically the rule requires the
5 program to be considered and screened in a market potential study (4CSR 240-3.164 (2)(A))
6 and then the program must be demonstrated to be cost effective (4CSR 240-3.164 (2)(B)) with
7 a TRC greater than 1.0. In addition, each demand side program must include all information
8 required by 4CSR 240-3.164 (2)(C).

9 Q. Has the Company screened this proposed CHP measure and found it to be cost
10 effective?

11 A. The Company has screened CHP (through its potential study and 2014 Chapter
12 22 triennial compliance filing¹⁴) as a measure and found it not to be cost effective as
13 explained by Company witness Richard A. Voytas in his surrebutal testimony. Mr. Voytas
14 states that "As table 4-3 shows, CHP is not cost effective for MEEIA 2016-2018. Relatively
15 minor amounts of potential become cost effective in 2025."¹⁵

16 Q. How does the Utility Stipulation value CHP benefits?

17 A. Paragraph 13 of the Utility Stipulation states:

18 For purposes of determining cost effectiveness, savings from CHP is defined
19 as follows:

20
21
$$\text{Fuel Savings (FS)} = (\text{FT} + \text{FG}) - \text{FCHP}$$

22 FS – total fuel savings

23 FT – avoided fuel use from on-site thermal production

24 FG – avoided fuel use from purchased grid electricity

25 FCHP – fuel use by the CHP system
26

¹⁴ Case No. EO-2015-0084.

¹⁵ Voytas surrebutal testimony at page 81, lines 12 - 13.

1
2 The determination of the cost effectiveness of CHP will also recognize any
3 reduced electric capacity on the Ameren Missouri system as a result of the
4 addition of CHP. Fuel from all sources is expressed in terms of BTUs.
5

6 Q. Does the Utility Stipulation approach to CHP with its fuel savings definition
7 and recognition of reduced electric capacity on the Ameren Missouri system as a result of
8 CHP comply with the MEEIA rules?

9 A. No. The Utility Stipulation approach to CHP gives no consideration as to
10 whether the end-use consumption of electricity on the customer's side of the electric meter is
11 reduced or modified.

12 Q. Does this conclude your testimony?

13 A. Yes.

Summary Analysis of Ameren Missouri MEEIA Cycle 1*, MEEIA Cycle 2 Application
and 6/30/2015 Utility Stipulation and Agreement***
(Millions of Discounted Dollars)**

<u>Benefits and Costs Summary</u>		Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
Energy Savings Target (GWh)		793	426	584	505	166	224	288	261	360
Demand Savings Target (MW)		170	114	123	99	36	56	71	78	68
<i>a</i>	Expected Benefits	\$ 499	\$ 261	\$ 350	\$ 307	\$ 89	\$ 119	\$ 192	\$ 172	\$ 231
<i>b</i>	Program Administration	\$ 79	\$ 70	\$ 99	\$ 45	\$ 38	\$ 54	\$ 34	\$ 32	\$ 45
<i>c</i>	Customer Incentives	\$ 55	\$ 56	\$ 86	\$ 31	\$ 14	\$ 29	\$ 24	\$ 42	\$ 57
<i>d</i>	Net Participant Cost	\$ 106	\$ 44	\$ 49	\$ 60	\$ 14	\$ 8	\$ 46	\$ 31	\$ 40
<i>e</i>	Participant Bill Reduction	\$ 566	\$ 355	\$ 479	\$ 380	\$ 145	\$ 188	\$ 185	\$ 215	\$ 291
<i>f = b + c</i>	Total UCT Cost	\$ 134	\$ 126	\$ 186	\$ 76	\$ 52	\$ 83	\$ 58	\$ 74	\$ 103
<i>g = b + c + d</i>	Total TRC Cost	\$ 240	\$ 170	\$ 234	\$ 136	\$ 66	\$ 91	\$ 104	\$ 105	\$ 143
<i>h = a / f</i>	UCT	3.72	2.07	1.89	4.04	1.71	1.44	3.31	2.32	2.25
<i>i = a / g</i>	TRC	2.08	1.54	1.50	2.26	1.35	1.31	1.85	1.64	1.62
<i>j = (c+e) / (c+d)</i>	PCT	3.86	4.11	4.19	4.52	5.67	5.84	2.98	3.52	3.56
<i>k = a - f</i>	UCT Net Benefits	\$ 365	\$ 135	\$ 165	\$ 231	\$ 37	\$ 36	\$ 134	\$ 98	\$ 129
<i>l</i>	Throughput Disincentive	\$ 95	\$ 44	\$ 60	\$ 61	\$ 17	\$ 23	\$ 34	\$ 27	\$ 37
<i>m</i>	100% Performance Incentive	\$ 19	\$ 19	\$ 23	\$ 12	\$ 5	\$ 6	\$ 7	\$ 14	\$ 17

<u>Customers as a Whole</u>		Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
<i>a</i>	Expected Benefits	\$ 499	\$ 261	\$ 350	\$ 307	\$ 89	\$ 119	\$ 192	\$ 172	\$ 231
<i>b</i>	Program Administration	\$ 79	\$ 70	\$ 99	\$ 45	\$ 38	\$ 54	\$ 34	\$ 32	\$ 45
<i>c</i>	Customer Incentives	\$ 55	\$ 56	\$ 86	\$ 31	\$ 14	\$ 29	\$ 24	\$ 42	\$ 57
<i>m</i>	100% Performance Incentive	\$ 19	\$ 19	\$ 23	\$ 12	\$ 5	\$ 6	\$ 7	\$ 14	\$ 17
<i>n = b+c+m</i>	Customers' Costs	\$ 153	\$ 145	\$ 208	\$ 88	\$ 57	\$ 89	\$ 65	\$ 88	\$ 119
<i>o = a - n</i>	Customers' Net Benefits	\$ 346	\$ 116	\$ 142	\$ 219	\$ 32	\$ 30	\$ 127	\$ 84	\$ 112
<i>p = a / n</i>	Benefits / Costs	3.26	1.80	1.68	3.49	1.56	1.34	2.95	1.96	1.94

<u>Non-Participating Customers</u>		Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
<i>a</i>	Expected Benefits	\$ 499	\$ 261	\$ 350	\$ 307	\$ 89	\$ 119	\$ 192	\$ 172	\$ 231
<i>b</i>	Program Administration	\$ 79	\$ 70	\$ 99	\$ 45	\$ 38	\$ 54	\$ 34	\$ 32	\$ 45
<i>c</i>	Customer Incentives	\$ 55	\$ 56	\$ 86	\$ 31	\$ 14	\$ 29	\$ 24	\$ 42	\$ 57
<i>l</i>	Throughput Disincentive	\$ 95	\$ 44	\$ 60	\$ 61	\$ 17	\$ 23	\$ 34	\$ 27	\$ 37
<i>m</i>	100% Performance Incentive	\$ 19	\$ 19	\$ 23	\$ 12	\$ 5	\$ 6	\$ 7	\$ 14	\$ 17
<i>q = b+c+l+m</i>	Customers' Costs	\$ 248	\$ 189	\$ 269	\$ 149	\$ 74	\$ 112	\$ 99	\$ 115	\$ 157
<i>r = a - q</i>	Customers' Net Benefits	\$ 251	\$ 72	\$ 82	\$ 158	\$ 15	\$ 7	\$ 93	\$ 57	\$ 75
<i>s = a / q</i>	Benefits / Costs	2.01	1.38	1.31	2.07	1.20	1.06	1.93	1.50	1.48

<u>Participating Customers</u>		Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
<i>d</i>	Net Participant Cost	\$ 106	\$ 44	\$ 49	\$ 60	\$ 14	\$ 8	\$ 46	\$ 31	\$ 40
<i>c</i>	Customer Incentives	\$ 55	\$ 56	\$ 86	\$ 31	\$ 14	\$ 29	\$ 24	\$ 42	\$ 57
<i>e</i>	Participant Bill Reductions	\$ 566	\$ 355	\$ 479	\$ 380	\$ 145	\$ 188	\$ 185	\$ 215	\$ 291
<i>t = c + d</i>	Customers' Costs	\$ 161	\$ 100	\$ 135	\$ 91	\$ 28	\$ 37	\$ 70	\$ 73	\$ 98
<i>u = c + e</i>	Customers' Benefits	\$ 621	\$ 411	\$ 565	\$ 411	\$ 159	\$ 217	\$ 209	\$ 257	\$ 348
<i>v = u / t</i>	Benefits / Costs	3.86	4.11	4.19	4.52	5.67	5.84	2.98	3.52	3.56

* Cycle 1
 ** Cycle 2
 *** Utility Stipulation

