2007-00553

EAST KENTUCKY POWER COOPERATIVE

December 20, 2007

RECEIVED
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PUBLIC SERVICE COMMISSION

Ms. Beth O'Donnell
Executive Director
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, Kentucky 40601

Dear Ms. O'Donnell:

Re: East Kentucky Power Cooperative, Inc ("EKPC") - Section DSM-3 Rate Schedule Report Outlining the Results of the Direct Load Control of Water Heaters and Air-Conditioners Demonstration Project

Pursuant to the requirements set forth in East Kentucky Power Cooperative, Inc.'s Section DSM-3 tariff, Direct Load Control of Water Heaters Program and Direct Load Control of Air-Conditioners Program, attached are an original and six copies of the report outlining the results of this demonstration project.

In addition, based on the results herein, EKPC is requesting by separate filing a resumption of this program until a permanent program is approved by the Commission.

If you have any questions concerning this filing, or if additional information is required, please contact me or Bill Bosta at EKPC headquarters.

Very truly yours,

Charles A. Lile
Senior Corporate Counsel

c: Dan Brewer - Blue Grass Energy
Bobby Sexton - Big Sandy RECC
Bill Bosta - EKPC

INTRODUCTION

In accordance with the Commission's Order of April 18, 2007 approving East Kentucky Power Cooperative's (EKPC) Request for a determination of a new demand-side management program, direct load control of water heaters and air conditioners, EKPC hereby submits its report of the results of the pilot DSM Program. This report consists of the following sections:

I. Description of Project
II. Results
III. Impact of the Weather
IV. Customer Satisfaction
V. Cost of Project
VI. Potential Impact of Full-Scale Program

I. DESCRIPTION of PROJECT

In January 2006, EKPC filed with the Kentucky Public Service Commission (PSC) a proposal to implement a demonstration project for the Direct Load Control of Water Heaters and Air Conditioners. Big Sandy RECC and Blue Grass Energy agreed to participate in a pilot program to determine whether the direct load control of air conditioners and water heaters (40 gallon minimum) would be a beneficial demand-side management program for the entire EKPC system. In April 2006, the Commission approved EKPC's application and authorized EKPC to proceed with the pilot program.

Following Commission approval, enrollment efforts for Blue Grass Energy began promptly in April 2006. The direct mail method was used as the means of communication, with potential customers receiving a letter from the CEO describing the demonstration project, the incentive, the terms and conditions of participation and other related information. A follow-up letter was sent in May 2006. Results were excellent. A total of 473 switches were installed on central air conditioning or heat pump units, and 244 switches were installed on electric water heaters. Installation work for the Blue Grass Energy participants was completed in July 2006.

Big Sandy RECC's enrollment process began in July 2006. The direct mail method was used for Big Sandy RECC as well. A reminder letter was mailed in August 2006 to potential customers. A total of 142 switches were installed on electric water heaters in the Big Sandy service territory. Installation work for the Big Sandy RECC participants was completed in October 2006.

The demonstration project covered two summers for air conditioning and 12-months for water heaters. The project was completed in September 2007.

EKPC and the participating member systems used a third party, GoodCents Solutions, located in Loganville, Georgia, to perform the enrollment, installation, and measurement & verification (M&V) functions during the demonstration project. GoodCents Solutions is a privately owned energy management company that provides residential and small-commercial demand response and energy efficiency programs to investor-owned, municipal, and cooperative utilities across North America. GoodCents has completed over 1,000,000 installations of load control devices for its utility clients. GoodCents has extensive experience with both large and small load management programs. It has successfully run load management programs for Louisville Gas & Electric, Cinergy, Flint Energies, Southern California Edison, Georgia Power, Commonwealth Edison, Ontario Hydro One, and Toronto Hydro.

In addition to the load control switches, GoodCents gathered end-use metered summer water heater data from 23 customers during the period of June 2006 through September 2006 and June 2007 through September 2007. Also, GoodCents gathered end-use metered winter water heater data from 24 customers during the period of November 2006 to March 2007. GoodCents gathered end-use metered air-conditioning data from 28 customers during the summer period of June through September of 2006 and June through September of 2007. This information was used in formulating the results of the project.

One of the key objectives of the program was to determine how DLC would perform in a field test before committing to a full-scale implementation.

Key measurements include (1) average demand reduction per switch, (2) the impact of weather on air conditioner and water heater load relief, (3) customer satisfaction, and (4) the potential impact of a full-scale program.

II. Results

Based on the load research information gathered during the study period, the demand reduction for both air conditioning and water heaters was significant.

In October 2007, GoodCents Solutions delivered its final report on measurement and verification results for the DLC demonstration project. Load impacts were reported in terms of kilowatts per water heater and per air conditioner. During the first summer of the pilot, for example, air conditioners were cycled using a 33% cycling strategy. The air conditioner compressor was not allowed to run for one out of every three 7 ½ minute intervals during the control period. In the summer of 2007, EKPC used a 50% cycling strategy. The air conditioner compressor ran every 7 ½ minute interval out of 15 minutes during the control period. The difference in the peak demand reduction was significant. As shown in Table 1, the 50% cycling approach resulted in a 1.1 KW reduction per appliance compared to a 0.60 KW reduction with 33% cycling. As indicated in the Customer Satisfaction section below, there was virtually no dissatisfaction with air conditioning comfort level during the study periods.

The demand reduction for water heater interruptions is also depicted in Table 1. As shown in the table, the demand reduction was 0.46 KW per appliance in the summer and 0.59 KW per appliance in the winter. The interruption of water heaters consisted of 4-

hour control during the on-peak period. This process was used for both the summer and the winter periods.

Table 1

Appliance	Summer Peak Savings per Unit (kW per appliance)	Winter Peak Savings per Unit (kW per appliance)
Central Air Conditioner Summer 2006 – 33% cycling	0.60 kW	N/A
Central Air Conditioner Summer 2007 – 50% cycling	1.10 kW	N/A
Water Heater	0.46 kW	0.59 kW

To perform direct load control, EKPC operated a button at EKPC headquarters and sent "signals" through the power line to the load control switch for air conditioning to Blue Grass Energy customers using the cycling strategy previously mentioned.

Water heaters were pre-programmed to shut down for a maximum time period of four hours. As water heaters are built to store water for future use, this time period is not unusual for accomplishing load reductions while maintaining customer comfort. Unlike air conditioning both participating cooperatives pre-programmed the control times.

During the demonstration project, EKPC initiated control during both primary control periods and secondary control periods. The primary control period was the four hour period where the EKPC peak most often occurs in a given month, while the secondary period is a different four hour period to cover other hours where EKPC might experience its peak for that month less frequently. For example, in winter months, the EKPC system most often peaks in the morning sometime between 6 AM and 10 AM, but occasionally in the winter the peak has occurred in the late afternoon.

Compared with the estimates included in the original Application, the actual measured impacts (both appliances) for the summer period are slightly higher than originally estimated (1.56 kW versus 1.37 kW), while the measured impacts for the winter are lower than expected (0.59 kW versus 1.03 kW). The measured results for water heater control in the winter were lower than expected. Upon investigation, it was found that these results are consistent with recent results at other utilities, and are consistent with trends in annual use for residential water heaters, which have shown a decline in the last decade stemming from more efficient appliances and shrinking household size (fewer people per dwelling).

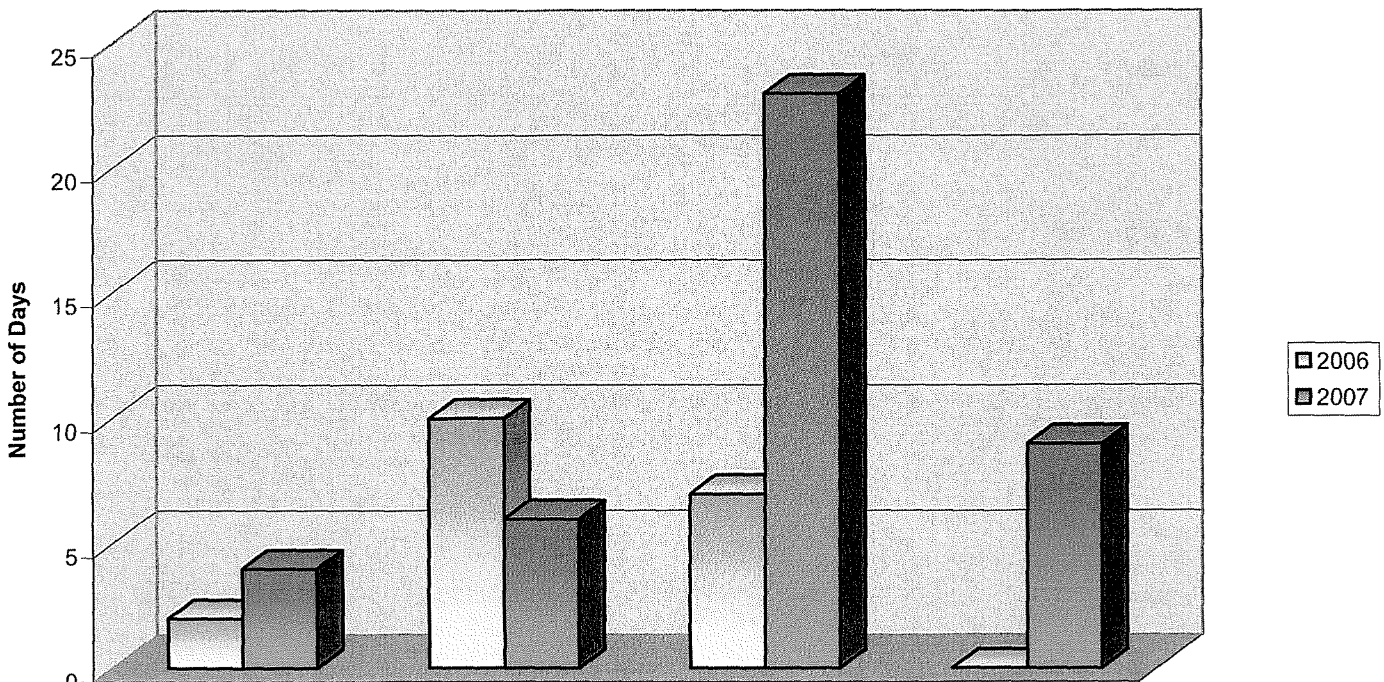
As indicated in its Application for approval, Blue Grass Energy and Big Sandy RECC used load control switches for their Automatic Meter Reading (AMR) systems to perform the direct load control function.

In addition, due to the nature of the program, the level of energy reduction during the study period was minimal. It is estimated that a very nominal reduction in energy cost (fuel and variable operation and maintenance cost) would result from this program.

III. Impact of the Weather

The variation of weather and climate can have a significant impact on the effectiveness of any load control program, particularly a program to control air conditioning in summer months. The central Kentucky area, for example, was slightly cooler than normal in the summer in 2006, while hotter than normal in the summer of 2007. Graph 1 below shows the number of days above 90 degrees for both 2006 and 2007. The summer of 2007 was much hotter than 2006 with 23 days in August reaching at least 90 degrees.

Graph 1
Number of Days Above 90 Degrees F



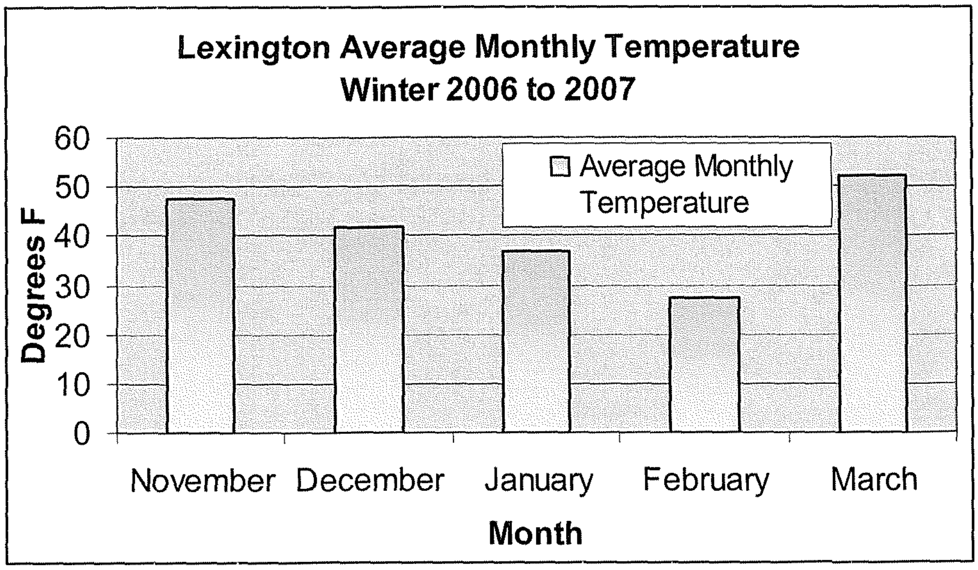
	June	July	August	September
2006	2	10	7	0
2007	4	6	23	9

Month

The summer of 2007 was an ideal time to be testing the impact of air conditioner load control. The range of weather conditions was conducive to obtaining a very good measurement of the air conditioner load response to the ambient temperatures. As a result, the demand reduction results for the summer of 2007 are representative of the per appliance reduction in demand anticipated under a permanent program.

As for water heating, the central Kentucky region had a fairly mild winter in 2006-2007, with most months recording a deficit of heating degree-days compared to past years. The month of February, however, recorded lower temperatures than normal and had a surplus of heating degree days compared to past years. Below, graph 2 shows the monthly average temperature for the winter.

The warmer winter in 2006-2007, when coupled with the hotter summer of 2007, resulted in what would be considered as a fairly normal weather period, resulting in very little, if any, weather effect on the water heating results.



IV. Customer Satisfaction

Customer Satisfaction, as measured by the level of customer retention, was very strong throughout the demonstration project. For example, out of 142 water heater project participants at Big Sandy RECC, only one customer asked to be removed from the program. Results were very good at Blue Grass Energy as well. Out of 473 air conditioning project participants, only 14 customers requested that the air conditioner controls be removed and only 8 out of a possible 244 participants in the water heater control project requested removal of their water heater switch..

V. Cost of Project

The total cost of the demonstration project was $368,393. This compares to EKPC's original estimate of $296,000. One significant factor that affected the ultimate cost level was the need to use a separate switch for each appliance within each home. EKPC had originally anticipated that one switch could perform both functions for water heater and air conditioning control in those Blue Grass Energy homes that participated in both functions. However, due to the location of each appliance in the home, EKPC determined that a separate switch had to be used for each appliance, thus increasing cost. In addition to increasing switch costs, this also increased the installation costs. The actual cost of the switches ranged from $130 - $150 per switch. This is slightly higher than the level estimated in the original Application.

The table below shows a comparison of actual costs to estimated cost for each major cost category.

	Cost Estimate	**Actual Cost**
Switches- BGE	$90,000	$115,717
Switches – BSRECC	$36,000	$ 21,497
GoodCents Solutions	$115,000	$188,815
Recruitment & Marketing	$10,000	$12,124
Leased Data Circuit	$12,000	-0-
Software & Training – BSRECC	$10,000	$7,950
Incentives – AC Incentives – WH/BGE Incentives – WH/BSRECC	$16,000 $ 7,000	$18,600 $2,350 $1,340
TOTAL	$296,000	$368,393

VI. Potential impact of a full-scale program

This demonstration project has provided important information about the cost and performance of residential DLC in the EKPC service territory. Results of this demonstration project show that demand reduction is likely and that customer satisfaction is high. To assure a positive benefit-cost ratio, EKPC will need volume to recoup its fixed costs (including program design, software and communications, marketing and call center, and M&V) thus displacing expensive blocks of power supply.

Attachment 1 to this report includes the results of a series of California DSM tests conducted using the results of the demonstration project as an estimate of the long-term effect of the demonstration project. EKPC prepared the attached analysis using 50,000 participants. The results of the California tests were all positive, with the Total Resource Cost test at a very robust 2.96 benefit-cost ratio.

The California DSM test results cited above are encouraging and EKPC anticipates filing an Application with the Commission for a permanent program during the first quarter of 2008. EKPC believes that the demand reduction results from the demonstration project are valid and that the key factors that will determine success or failure are (1) the number of member systems that will actually implement DLC, and (2) the participation rate among eligible end-user customers. EKPC intends to develop a permanent program that will enable the Company to maximize participation rates among its Members and experience the demand reductions that the Pilot program has demonstrated.

ATTACHMENT 1

SECTION III

KEY ASSUMPTIONS

1. EKPC has prepared the cost-effectiveness tests based on the costs and results experienced in the demonstration project.

2. For purposes of the cost-effectiveness test, EKPC has assumed that there would be 50,000 participants and that the expenses of the program would be shared equally between the Member Systems and EKPC, with the exception of the incentives to participants which would be paid by EKPC.

3. The benefits and costs for this program are expressed in terms of the Standard California cost-effectiveness tests. EKPC utilized the software package *DSManager* that was developed by the Electric Power Research Institute (EPRI). The tests include (1) Rate Impact Measure, (2) Participant Test, and (3) Total Resource Cost.

4. EKPC's generation capacity credit is based on the difference in the peak load contributions of two appliances with and without load control. The first is a typical residential central air conditioner versus that of a central air conditioner that is controlled during peak days in June through September using a 50% cycling control strategy. The second is a typical electric water heater versus that of an electric water heater that is shut off for 4 hours during peaks, January through December. Based on actual demonstration impacts, the peak summer reduction for the load control of both the appliances is 1.56 kW per participant, and the peak winter reduction is .59 kW.

5. EKPC's production energy cost savings are minimal due to the nature of this program, and are based on the estimated reduction in fuel and variable operating and maintenance expenses stemming from the very modest decrease in kWh generated as a result of the program. EKPC estimates that 10 kWh per year will be saved for each air conditioner that participates and 10 kWh per year for each water heater.

6. EKPC anticipates four categories of costs associated with a permanent program: one time system costs, one time costs per new participant, annual marketing and operating costs, and annual maintenance costs. EKPC estimates that the one time system costs will be approximately $820,000 and include software, program planning, and project setup. Annual marketing and operating costs are $401,800 and include marketing, communications, program administration, measurement & verification, and call center. EKPC estimates that the one time costs per new participant will be $323 per participant and cover the recruitment costs, load control switch costs, and the installation costs. Costs in future years escalate at an assumed 3% rate of inflation. For purposes of this analysis, these costs were assumed to be shared equally between EKPC and the member system. Finally,

EKPC estimates that the annual maintenance costs will be $2.10 per participant per year.

7. Wholesale demand and energy rates are based on EKPC wholesale tariff Schedule E-2, effective as of January 1, 2006.

8. Retail rates are based on South Kentucky RECC's residential rate (Average rate among the 16 distribution systems on a cents per kWh basis) as of January 1, 2006.

9. The incentive to the participants is $30 per customer per year for water heating and air conditioning.

10. There will be no cost to the participant.

11. For purposes of determining the present value of future benefits and costs of the program, a discount rate of 6.5% was used for both the Rate Impact Measure and the Total Resource Cost test and 13% for the Participant test.

12. The program assesses participation for five years. Demand and energy savings were evaluated for a program time of 20 years.

Direct Load Control
Standard California Tests
Summary of Benefits and Costs

Ratepayer Impact Test

Line		Total Benefits	Total Costs	Net Benefits	B / C Ratio
1	Distribution System	$ 49,508,383	$ 31,327,070	$ 18,181,313	1.58
2	EKPC	$ 68,770,174	$ 61,568,473	$ 7,201,701	1.12

Participant Test

Line		Total Benefits	Total Costs	Net Benefits	B / C Ratio
3	Participant	$ 12,035,228	$ -	$ 12,035,228	#DIV/0!

Total Resource Cost Test

Line		Total Benefits	Total Costs	Net Benefits	B / C Ratio
4	Total Resouce Cost Test	$ 68,770,174	$ 23,249,383	$ 45,520,791	2.96

Distribution System Ratepayer Impact Test

LINE			LINE	EXPLANATION
1	*Benefits*		1	Avoided wholesale electricity payments, plus incentives received
2	D. S. Electric Acquisition Decrease	$30,163,195	2	PV of decrease in Distribution Systems' wholesale power expense paid to EKPC. Based on EKPC's Wholesale Tariff Schedule E-2.
3	Incentives Received from EKPC	$19,345,189	3	PV of incentives paid by EKPC to DS evaluated over 20 years.
4	Total Benefits	$49,508,383	4	Line 2 plus Line 3
5	*Costs*		5	Utility program costs (including incentives) plus net lost revenues caused by reduced sales.
6	D. S. Base Electric Revenue Decrease	$783,810	6	PV of D.S. reduction in electric revenues from decrease in kWh sales. Based on South Kentucky A rate.
7	Adjusted Revenue Decrease	$8,778	7	PV of Fuel Adjustment Clause evaluated over 20 years.
8	Fixed Administrative Cost	$2,954,316	8	PV of $348,400 in year 1, $194,052 in year 2, then escalated at 3% per year.
9	Distribution System Variable Cost	$8,234,977	9	PV of $162 one-time cost per new participant; $1.05 maint./yr/participant; esc. @ 3%/yr.
10	Incentives Paid	$19,345,189	10	PV of incentives over 20 years
11	Total Costs	$31,327,070	11	Line 6 plus Line 7 plus Line 8 plus Line 9 plus Line 10.
12	*Net Benefits*	$18,181,313	12	Line 4 minus Line 11
13	Benefit / Cost Ratio	1.58	13	Line 4 divided by Line 11

Note: Incentives are defined as Customer incentive payments of $30 per year per participant.

East Kentucky Power Cooperative Ratepayer Impact Test

LINE			LINE	EXPLANATION
1	*Benefits*		1	Avoided supply costs (production, transmission, and distribution) based on energy and load reductions.
2	Electric Production Cost Decrease	$1,124,407	2	PV of EKPC's electric production cost decrease over 20 years. Includes fuel and variable operating and maintenance expense.
3	Generation Capacity Credit	$54,401,994	3	PV of EKPC's avoided capacity costs due to reduction in generation evaluated over 20 years.
4	Transmission Capacity Credit	$13,243,773	4	PV of avoided transmission capacity costs.
5	Total Benefits	$68,770,174	5	Line 2 + Line 3 + Line 4
6	*Costs*		6	Utility program costs (including incentives) plus net lost revenues caused by reduced sales.
7	Incentives Paid	$19,345,189	7	PV of incentives paid to Member Systems
8	Base Revenue Decrease	$30,154,401	8	PV of EKPC's reduction in base revenues; based on EKPC's Wholesale Tariff Schedule E-2.
9	Adjusted Revenue Decrease	$8,794	9	PV of EKPC's Fuel Adjustment Clause revenue reduction, evaluated over 20 years.
10	Fixed Administrative Cost	$3,825,113	10	PV of $873,400 in year 1, $219,802 in year 2, then escalated at 3% per year.
11	Variable Costs	$8,234,977	11	PV of $162 one-time cost per new participant; $1.05 maint./yr/participant; esc. @ 3%/yr.
12	Total Costs	$61,568,473	12	Line 8 + Line 9 + Line 10 + Line 11
13	*Net Benefits*	$7,201,701	13	Line 5 minus Line 12.
14	Benefit / Cost Ratio	1.12	14	Line 5 divided by Line 12.

Note: Incentives are defined as Customer incentive payments of $30 per year per participant.

Participant Test

LINE			LINE	EXPLANATION
1	*Benefits*		1	Incentive from Distribution System, plus a reduction in electric bill.
2	Customer Electric Bill Decrease	$487,713	2	PV of reduction in Participants' retail electric bill due to decrease in energy consumption. Based on South Kentucky A rate..
3	Customer Incentives	$11,547,515	3	PV of incentives received from Distribution Systems.
4	Total Benefits	$12,035,228	4	Line 2 + Line 3
5	*Costs*		5	Participants' direct cost of participation.
6	Customer Investment	$0	6	No cost to the Participant to participate in these programs.
7	Total Costs	$0	7	Line 6.
8	*Net Benefits*	$12,035,228	8	Line 4 minus Line 7.
9	Benefits / Cost Ratio	#DIV/0!	9	Line 4 divided by Line 7. No ratio - division by zero.

Note: Incentives are defined as Customer incentive payments of $30 per year per participant.

Total Resource Cost Test

LINE			LINE	EXPLANATION
1	*Benefits*		1	Avoided supply costs (e.g.production, transmission, and/or distribution) based on energy and load reductions.
2	EKPC Electric Prod Cost Decrease	$1,124,407	2	PV of EKPC's electric production cost decrease evaluated over 20 years. Includes fuel and variable operating and maintenance expense.
3	EKPC Generation Capacity Credit	$54,401,994	3	PV of EKPC's avoided capacity costs due to reduction in generation.
4	Transmission Capacity Credit	$13,243,773	4	PV of avoided transmission capacity costs.
5	Total Benefits	$68,770,174	5	Line 2 + Line 3 + Line 4
6	*Costs*		6	Total program costs to participants, the Distribution Systems, and EKPC. Ignoring transfers (incentives, bill payments).
7	Participants' Investment	$0	7	
8	Distribution System Fixed Cost	$2,954,316	8	PV of $348,400 in year 1, $194,052 in year 2, then escalated at 3% per year.
9	Distribution System Variable Cost	$8,234,977	9	PV of $162 one-time cost per new participant; $1.05 maint./yr/participant; esc. @ 3%/yr.
10	EKPC Fixed Admin Cost	$3,825,113	10	PV of $873,400 in year 1, $219,802 in year 2, then escalated at 3% per year.
11	EKPC Variable Cost	$8,234,977	11	PV of $162 one-time cost per new participant; $1.05 maint./yr/participant; esc. @ 3%/yr.
12	Total Costs	$23,249,383	12	Line 9 + Line 10 + Line 11
13	*Net Benefits*	$45,520,791	13	Line 5 minus Line 12
14	Benefit / Cost Ratio	2.96	14	Line 5 divided by Line 12