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Senior Pricing Analyst

December 1, 2008

Ms. Jean D. Jewell
Secretary
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Subject: 2008 Irrigation Peak Rewards Program Report
Case No. IPC-E-06-22

Dear Ms. Jewell:

Enclosed are eight (8) copies of Idaho Power Company's Irrigation Peak Rewards Program Report for 2008. This annual report is in compliance with Order No. 30194. If you have any questions regarding this filing, please feel free to contact me at 388-2742 or Pete Pengilly at 388-2281.

Sincerely,

Scott D. Sparks

cc: Ric Gale
Greg Said
Mike Youngblood
Pete Pengilly
P&RS/Legal Files

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Irrigation Peak Rewards Program Report

December 1, 2008

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EXECUTIVE SUMMARY

The Irrigation Peak Rewards Program (the Program) is a voluntary demand response program available to Idaho Power's agricultural irrigation customers since 2004. The Program is designed to reduce peak load by turning off participating irrigation pumps during peak demand hours through the irrigation season in return for a financial incentive. Through this Program, the Company has been successful in reducing load during the summer afternoon hours when overall costs to provide energy are typically higher.

On September 18, 2006, Idaho Power (the Company) filed with the Idaho Public Utilities Commission (the Commission) a request for authorization to implement certain changes to the Program to improve participation. The first proposed change was to increase the demand credits offered to participating customers. Second, the Company proposed to allow more customers to participate by decreasing the pump horsepower (hp) limit from 100 hp to 75. On November 30, 2006 the Commission approved the proposed changes through Order No. 30194 and subsequently, the Company implemented the changes during the 2007 irrigation season. The Commission's Order No. 30194 directed the Company to file a report annually on December 1 for three years. This report provides the Commission with the 2008 operational results of the Irrigation Peak Rewards Program, and is filed in compliance with Order No. 30194. The operational results presented in this document represent a review of the Program's performance in 2008 on a system-wide basis.

The 2004 Integrated Resource Plan (IRP) set an initial load reduction target for the Program of 30 MW. The 2006 changes to the Program were estimated to achieve an additional 4.5 MW load reduction for a total of 34.5 MW at the generation level, which is adjusted for line losses. At the customer level this equates to an overall load reduction of 30.5 MW, which removes line losses. The peak reduction numbers reported throughout the remainder of this document are for Idaho Power's service territory in Idaho and Oregon and are presented at the customer level.

The Program enrollment for 2008 was 897 service points across five geographic regions of the Company's Idaho and Oregon service territories. Within these five regions, there were 3,955 eligible metered service points with at least 100 cumulative hp. Another 949 service points were eligible with pumps ranging from 75-99 cumulative hp, with 75 hp being the minimum amount eligible under the Program. Approximately 1,340 customers operated the 4,904 eligible service points

The Program utilizes pre-programmed, electronic, time-activated switches to turn off pumps of participating irrigation customers during pre-determined intervals in exchange for a financial incentive. Customers can choose to participate one, two, or three weekdays per week during the months of June, July, and August. The following are the interruption options (reported in Mountain Standard Time) available to customers with the corresponding incentive amounts:

- One weekday per week, 4 p.m. to 8 p.m. $2.01 per kW Demand
- Two weekdays per week, 4 p.m. to 8 p.m. $3.36 per kW Demand
- Three weekdays per week, 4 p.m. to 8 p.m. $4.36 per kW Demand

The monthly incentive amount credited to customers was calculated for each metered service point by multiplying the monthly billing demand for the months of June, July, and August by the corresponding incentive amount based on the interruption option selected by the customer.

Throughout 2008, the Company continued to share Program information and progress with the Energy Efficiency Advisory Group (EEAG) members through Program updates. Members of EEAG represent a cross-section of customer interests including residential, industrial, commercial and agricultural. In 2008, EEAG membership also included Company representation, Commission Staff members (Staff) and a representative from the Idaho Irrigation Pumpers Association (IIPA).

In the spring of 2008 Idaho Power convened a workshop with the IIPA and Staff to discuss ideas to improve the Program. The outcome of this workshop resulted in a proposal that was presented to the EEAG and is currently before the Commission seeking approval for significant changes to the Program. Among the proposed changes are increased incentives offered to Program participants. It is anticipated by the Company that the proposed changes will provide increased peak demand reduction through the Program. If the proposal is approved by the Commission, the results of the proposed changes will be presented in the 2009 Irrigation Peak Rewards Report to be submitted by December 1, 2009.

Summary of Results

The following items summarize the key results of the Program on a system-wide basis:

- In 2008 the Program achieved a maximum peak load reduction of 34.5 MW.

- Two hundred sixty (260) customers, or 19.4% of the 1,340 eligible customers, chose to participate in the Program.

- Eight hundred ninety-seven (897), or 18.3%, of the 4,904 eligible metered service points were enrolled in the Program.

- Of the 897 enrolled service points, seventy-three (73) were pumps with 75-99 hp. All other enrolled pumps were 100 hp or greater.

- The Program achieved a total billing demand enrollment of 164,733 kW.
- The Program produces substantial and measurable impacts on peak demand. The total load reduction from 4-8 p.m. associated with the Program averaged 27.8 MW in June, 29.6 MW in July, and 21.1 MW in August.

- The Program costs as of October 31, 2008 were $1,420,307.

- The Program results show a 30-year average benefit cost (B/C) ratio of 1.09.

Conclusions

- The Company plans to continue the Program because it is a cost-effective way to reduce customer demand at the optimal time of day. However, the company has recently filed with the Commission to add a dispatchable option to this Program.

- In 2008, continued participation of eligible service points enrolled in the Program helped the Company to achieve its 2004 Integrated Resource Plan (IRP) targets for peak load reduction.

- The Program achieved a maximum peak load reduction that occurred during the last two weeks in June of 34.5 MW at the customer level. The average peak reduction in July was 29.6 MW. The Program had a target load reduction of 30.5 MW at the customer level.

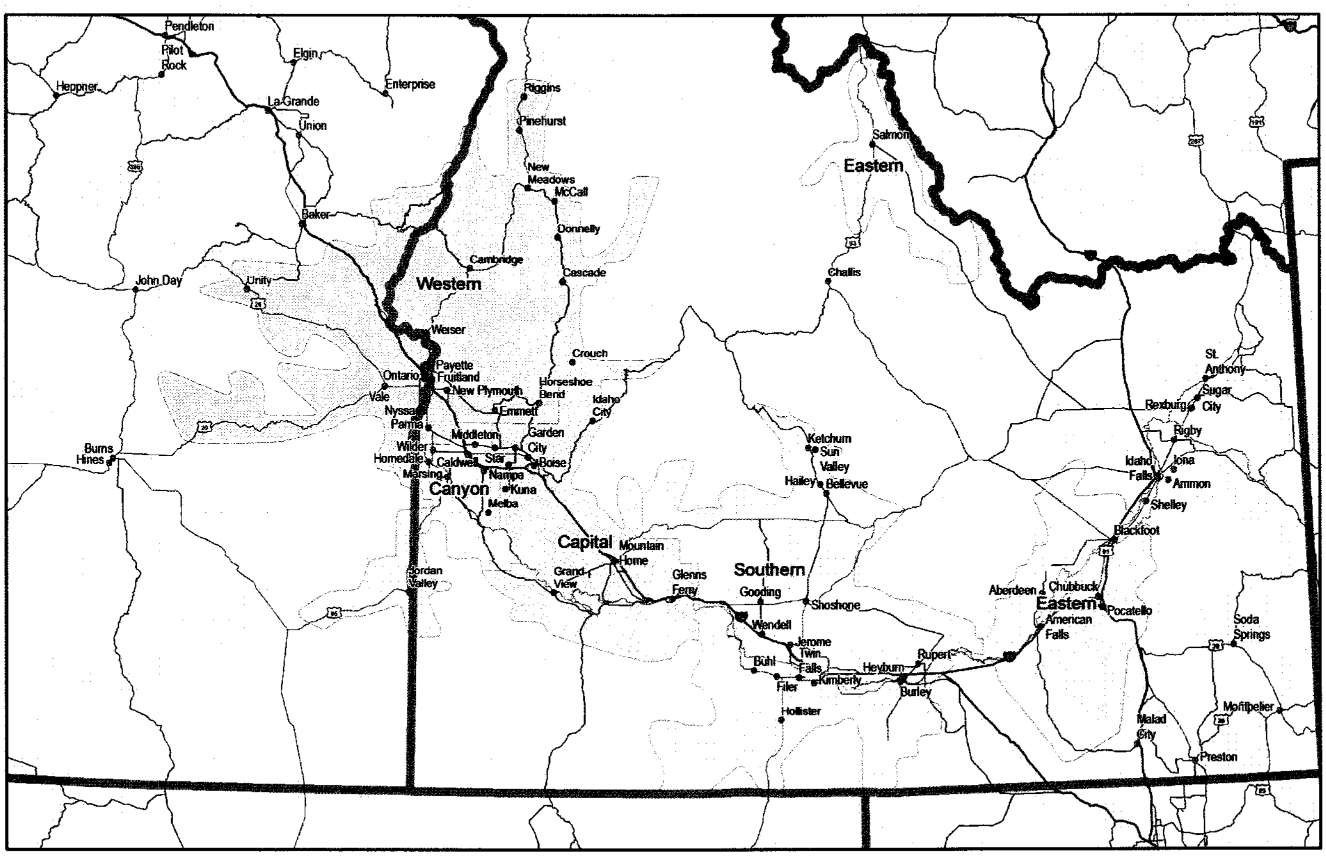
REVIEW OF PARTICIPATION, OPERATIONS, AND LOAD REDUCTION

1. Participation

Informational letters were mailed in February of 2008 to eligible customers. The letters were the primary method of marketing the Program. Each customer letter included a Program explanation, the Program's incentive structure, a listing of the customer's eligible service points, and a Program application. In addition, follow up telephone calls were made in March 2008 to all prior Program participants that had not yet sent in their application. Significant effort, including customer visits, was made to enroll as many customers as possible.

Map 1 portrays Idaho Power's service territory divided into five regional areas ("region"). The regions are titled Western, Canyon, Capital, Southern, and Eastern. These regions will be used throughout this report referring to Program information.

Map 1. Idaho Power service territory and regions.



Graph 1 represents the distribution of Program participants by area.

Graph 1. Distribution of Participants.

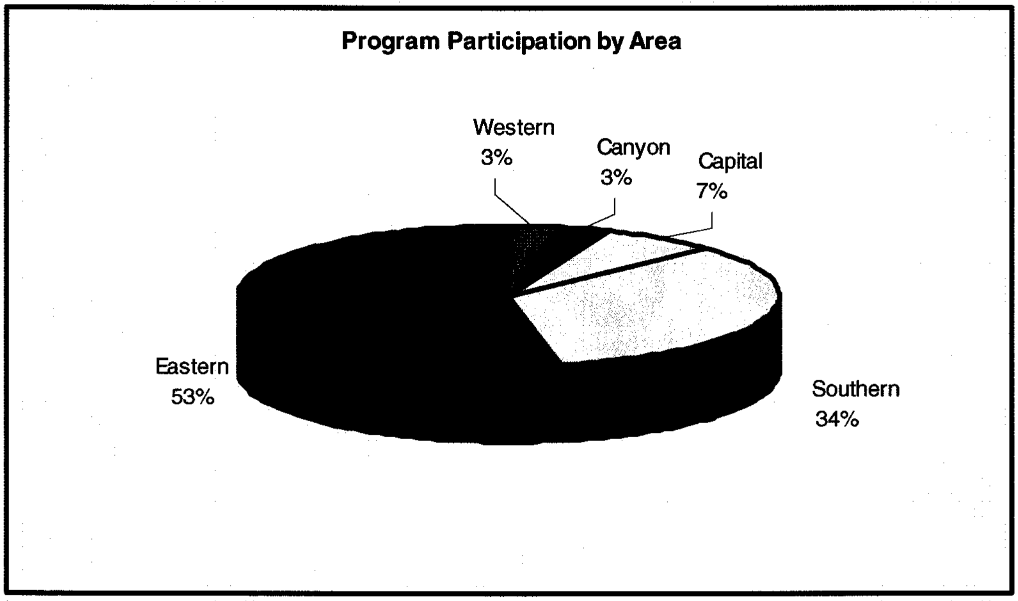


Table1 lists the total number of eligible service points and the participation levels by area.

Table 1. Service points by area.

IDAHO POWER REGION		ELIGIBLE SERVICE POINTS	SERVICE POINTS ENROLLED	ENROLLED PECENTAGE BY AREA
Western		217	26	12.0%
Canyon		340	23	6.8%
Capital		512	64	12.5%
Southern	Twin Falls	1,222	134	11.0%
	Mini-Cassia	1,035	171	16.5%
Eastern		1,578	479	30.4%
TOTAL SERVICE POINTS		**4,904**	**897**	**18.3**

Table 2 compares how the participating service points were distributed across the Company's service territory, along with the interruption options for each area.

Table 2. Interruption option distribution by service point.

		INTERRUPT OPTION 1	INTERRUPT OPTION 2	INTERRUPT OPTION 3	
IDAHO POWER REGION		**1 Days/Week**	**2 Days/Week**	**3 Days/Week**	**TOTAL**
Western		6	6	14	26
Canyon		14	0	9	23
Capital		38	8	18	64
Southern	Twin Falls	31	49	54	134
	Mini-Cassia	138	13	20	171
Eastern		255	119	105	479
TOTAL SERVICE POINTS		**482**	**195**	**220**	**897**

2. Program Opt-out

During the 2008 irrigation season, twelve (12) service points were removed from Program participation after June 1 due to various unforeseen circumstances by customers. Under the Program, if a service point is taken out of the Program after June 1, the participant is assessed a fee of $100. This resulted in a total of $1,200 which was credited to the Energy Efficiency Rider funding account to offset the initial Program costs.

3. Interruption Failures

Electronic timers manufactured by Grasslin Controls Corp. (Model GMX-891-0-24) were used to interrupt power to the customers' pumps during the interruption period. The timers were installed in the pump motor control circuit to prevent the pump from running during the interruption period. In order to meet the load reduction targets of the Program, the Company tries to minimize interruption failures. However, there were a small number of interruption failures discovered in 2008. In most cases the failures were corrected quickly with little or no impact to Program performance.

Most of the electronic timers operated without incident with less than 3% percent of participants requesting a follow-up visit. The timer issues requiring a follow-up visit are detailed in Table 3. **Table 3** lists the types of problems resolved by either Company personnel or contracted electricians.

Table 3. Known equipment problem resolutions.

ISSUE	QUANTITY
Replaced faulty time clock*	45
Electrician troubleshooting calls	50
TOTAL	**95**

*Replaced during re-programming in the spring.

While each of the known timer related problems detailed in Table 3 were resolved in a timely manner, a review of the Company's load research meter data revealed that there were some failures that went undetected for the entire irrigation season. Fifty-four (54) load research meters are distributed among the 897 participating service points in order to study the usage patterns of the customers and the load impact of the Program. The data showed that the energy demand that failed to be included in scheduled interruptions increased from 2007 by about 16%. The interruption failures are evident in the load reduction graphs provided in this report. Upon further investigation, it was found that these failures were due to various mechanical problems. The Company continues to address this issue through monitoring of load research data along with an increased number of site visits for electronic timer inspections.

4. Load Reduction Achieved

The Program load reduction impacts were determined by utilizing information and conclusions from the impact evaluation conducted in 2004 by Summit Blue Consulting, LLC. The evaluation utilized load research meter data for both Program participants and non-participants. This information was used in a regression analysis to develop a statistical kW load model. The model considered weather conditions, time of day, day of week, and month in determining realization rates for six 2-week periods during the course of the irrigation season. The Company has utilized these realization rates since the 2005 season.

The realization rate is defined as the likelihood an irrigation service point is operating during the interrupt period, and provides a clear picture of Program impacts. The realization rate can be characterized as simply the percentage of monthly billing demand that is expected to result in an actual load reduction on the system during a given interruption period. The realization rate is highest at the end of June and the beginning of July when most irrigation pumps are operating nearly 24 hours-a-day, 7 days-a-week. The realization rate is lower later in the irrigation season when irrigation pumps are turned off due to crop maturity.

Table 4 shows the Program evaluation results from the Summit Blue impact analysis for each of the six 2-week time periods. The highest realization rate occurred during the second half of June, with a realization rate of 64%. The lowest realization rate occurred during the second half of August, with a realization rate of 32%. The average total realization rate is 50%. These realization rates were used to calculate the Program load reduction for this year.

The Company verified the realization rates prepared by Summit Blue through past and current analyses, including analysis of the 2008 load research data. Based on these analyses, Idaho Power believes the realization rates from the Summit Blue study continue to be a reliable and accurate means to estimate the Program's load reduction. Idaho Power does not propose any changes to the realization rates at this time, but will continue to review the realization rates in the future.

Table 4. Realization rates by period.

PERIOD	Idaho Power Realization Rate
1st half of June	41%
2nd half of June	64%
1st half of July	60%
2nd half of July	53%
1st half of August	49%
2nd half of August	32%
AVERAGE	**50%**

The Company attempts to distribute the enrolled kW evenly throughout each weekday. However, due to service point size variability, enrollment requests by customers, and enrollment opt-outs, etc., the load cannot be exactly balanced.

The peak billing demand data for the months of June, July, and August 2008 were used to estimate the amount of load enrolled in the Program. The total billing demand enrolled in the Program was 164,733 kW. **Table 5** shows how the enrolled load was distributed by region.

Table 5. Enrolled load by area.

	ENROLLED BILLING DEMAND BY REGION (KW*)				
IDAHO POWER REGION		**1 Days/Week**	**2 Days/Week**	**3 Days/Week**	**TOTAL**
Western		967	702	977	2,646
Canyon		1,924	0	882	2,806
Capital		16,991	1,193	2,929	21,113
Southern	Twin Falls	6,956	8,213	8,615	23,784
	Mini-Cassia	29,476	2,877	3,717	36,070
Eastern		44,555	18,489	15,271	78,315
TOTAL SERVICE POINTS		**100,869**	**31,474**	**32,390**	**164,733**

*It is important to note that this billing demand level would be achieved only if 100% of the pumps enrolled in the Program were all running at the scheduled interruption time.

Table 6 shows the average MW reduction by day for each two week period achieved utilizing the realization rates.

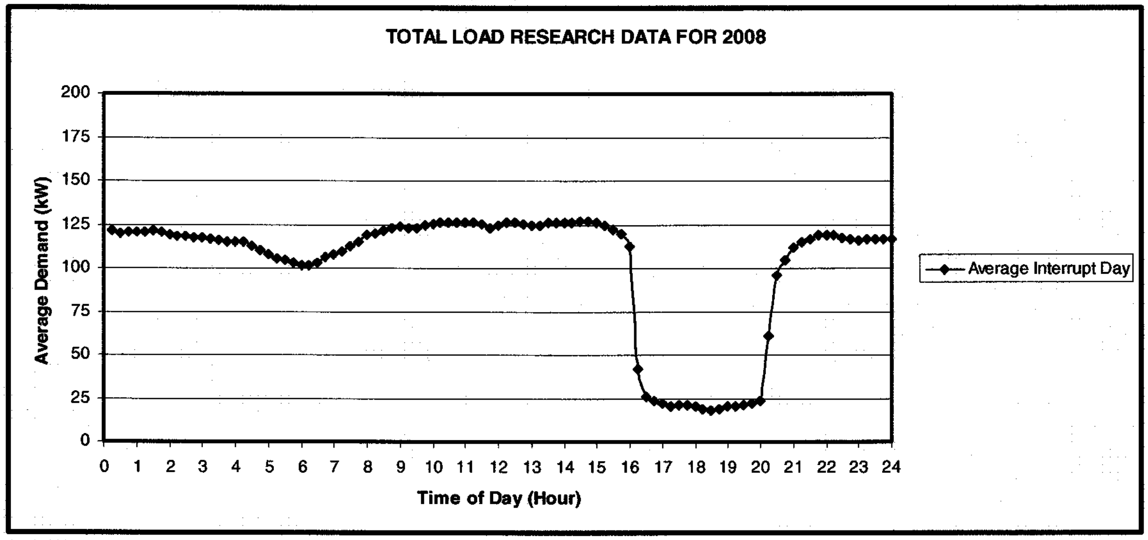
Table 6. Average MW reduction utilizing realization rates by period.

	Realization Rate	MON	TUE	WED	THUR	FRI	Average
	%	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
1st half of June	41	20.45	22.60	22.19	22.33	21.78	21.87
2nd half of June	64	31.32	35.15	34.35	34.55	33.71	33.82
1st half of July	60	29.13	32.90	31.96	32.39	31.20	31.52
2nd half of July	53	25.44	29.06	27.94	28.61	27.27	27.66
1st half of August	49	23.52	26.87	25.83	26.45	25.22	25.58
2nd half of August	32	15.36	17.55	16.87	17.27	16.47	16.70

As reported earlier, the Company has a sample of 54 load research meters installed on participating service points. These meters are distributed in a manner similar to participation rates for each area. This data was collected and analyzed and is shown in the following graphs.

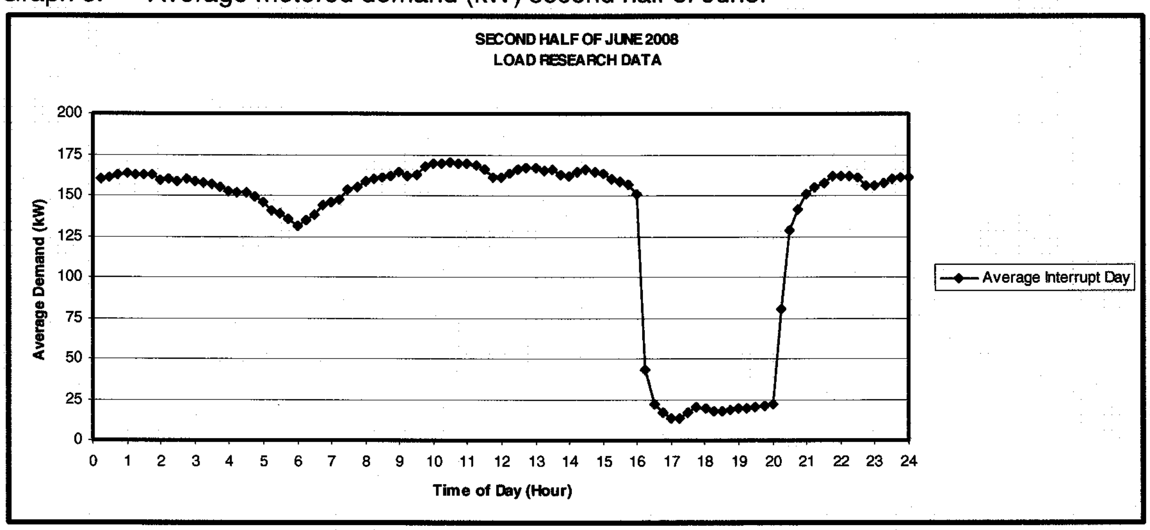
Graph 2 displays the average hourly kW for all days in June, July, and August and shows the average load reduction per participating metered service point within the load research sample. The graphed data represents all interrupt days in 2008.

Graph 2. Average metered demand (kW).



Graph 3 displays the average hourly kW for all days in the second half of June and shows the average load reduction per participating metered service point within the load research sample. The graphed data represents all interrupt days in the second half of June 2008.

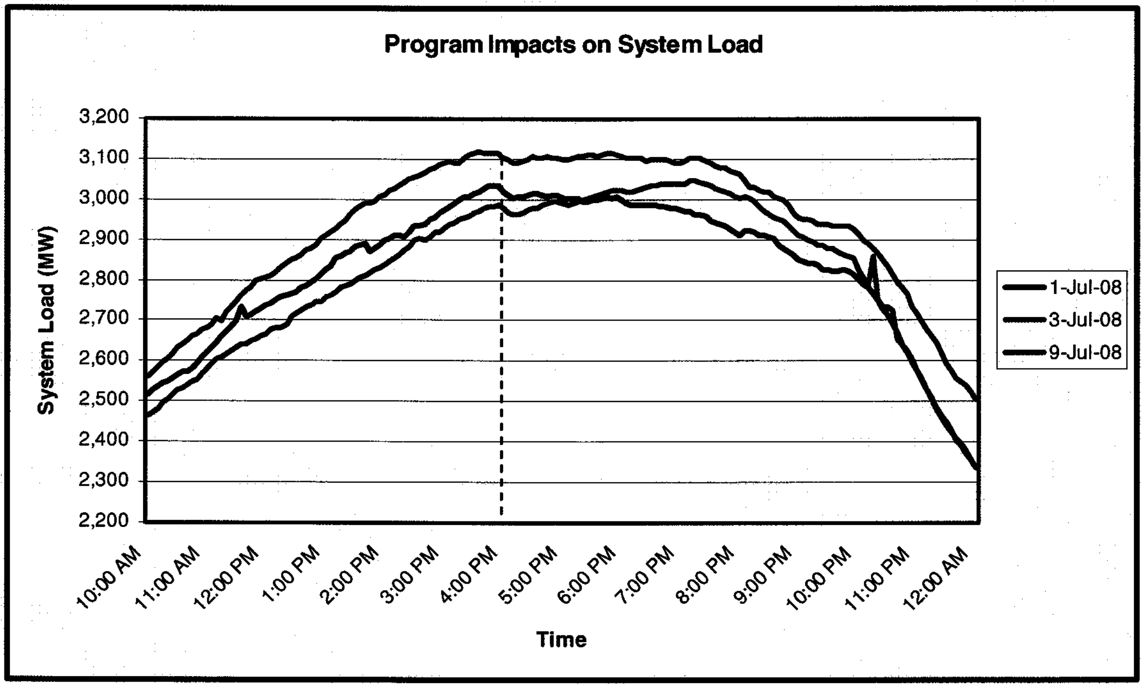
Graph 3. Average metered demand (kW) second half of June.



Another way to view program impact is to look at total system firm load data. The system firm load during the summer months has the greatest electrical demand of the year. The highest peak load historically occurs in late June or July between 4-8 PM.

Graph 4 represents demand response impact to the entire Company system firm load on various days in July 2008. The reduction in system firm load as a result of the Program occurs at 4 PM for the corresponding days and is approximately 30-40 MW for each day. However, July 3rd includes system load impacts from the A/C Cool Credit program. The A/C Cool Credit program was initiated at 3:00 pm on July 3rd. The line representing July 9th also includes impacts from the A/C Cool Credit program. The A/C Cool Credit program was utilized beginning at 4:00 pm on July 9th.

Graph 4. Demand response impact on Company system firm load.



COST EFFECTIVENESS

1. Program Costs

Table 7 displays the annual Program costs as of October 31, 2008. Program costs remain consistent on a year to year basis. However, the administration costs for 2008 include additional time spent on the proposed Program re-design for 2009.

Table 7. Program costs.

ITEM	PROGRAM COSTS
Electronic timers	$20,064.20
Contracted electricians	$67,318.42
Incentive payments	$1,241,494.75
Marketing and Administration	$91,479.51
TOTAL	$1,420,307.20

2. Benefit-Cost Analysis

The 2008 Peak Rewards Program results were applied to the cost-effectiveness model that was used when the Program was developed. **Table 8** summarizes the inputs that were used in the cost effectiveness model. In 2008, the Program results yielded a 30-year average benefit-cost ratio of 1.09.

Table 8. Benefit-cost model inputs

DESCRIPTION	INPUT
Number of metered service points	897
Overall Program realization rate	50%
Average service point, billing kW (peak month)	184
Enrolled peak, kW	164,733
Average July peak reduction (MW)	29.6
Participant distribution by area	
Western	3%
Canyon	3%
Capital	7%
Southern	34%
Eastern	53%
Service point interruption option	
1 day per week	54%
2 days per week	22%
3 days per week	24%
Actual Program Cost (as of Oct. 31, 2008)	$1,420,307.20