Irrigation Peak Rewards Program Report

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Executive Summary

The Irrigation Peak Rewards program (the program) is a voluntary demand response program that has been 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, Idaho Power has been successful in reducing load during the summer afternoon hours, which are the hours that are driving Idaho Power's need for new resources.

A major change in the demand response program occurred in 2009. This change expanded the dispatch capability of Idaho Power to reduce system demand during critical summer peak load events. The Irrigation Peak Rewards program, originally identified as a resource in 2004, was transitioned to act primarily as a direct load control or dispatch program. In prior years, demand reduction through the program was controlled only with programmed timers that provided demand reduction from irrigation pumping systems from 4:00 p.m. to 8:00 p.m. on weekdays in June, July, and August. Options added to the program in 2009 allowed direct load control or dispatch capabilities to match demand response resources with actual system peaks. The change in the program has increased the programs peaking resource capacity from its previous range of 34 to 37 megawatt (MW) to a forecasted impact of 260 MW at program maturity in 2012. Actual demand reductions from the revised program will depend on the level of irrigation customer participation and Idaho Power need.

This report provides the Idaho Public Utilities Commission (IPUC) with the 2009 operational results of the Irrigation Peak Rewards program, and is filed in compliance with IPUC Order No. 30194. The operational results presented in this document represent a review of the program's performance in 2009 on a system-wide basis.

The redesigned Irrigation Peak Rewards program was introduced at the October 2, 2008, Energy Efficiency Advisory Group (EEAG) meeting. Members of EEAG represent a cross-section of customer interests, including residential, industrial, commercial, and agricultural. IPUC staff are also members of the EEAG. Idaho Power proposed that the Irrigation Peak Rewards program include a dispatch demand response option offered to Idaho Power customers in Idaho and Oregon. Three options would be available for customers to choose between: 1) the Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn participants' pumps on or off, or 3) a Manual Dispatch Option for large service location with 1,000 horsepower (Hp) or greater option that allows participating customers, after being notified by Idaho Power, to turn pumps off manually during summer peak hours.

Based on the success of the current Irrigation Peak Rewards program and the potential for substantially increased cost-effective, peak-demand reduction, the EEAG recommended that Idaho Power expand the program. Throughout 2008, Idaho Power researched various equipment, options, and costs for dispatch equipment for use on irrigation pumps.

The Irrigation Peak Rewards program, which included the dispatch demand response option, was filed with the IPUC on November 10, 2008, and approved by the IPUC on January 14, 2009. The program was approved in Oregon by the Public Utility Commission of Oregon (OPUC) on February 25, 2009. Idaho Power offered the program to all agricultural customers receiving

service under Irrigation Rate Schedule 24 in 2009. Throughout 2009, Idaho Power continued to share program information and progress with EEAG members through program updates.

Details on the approved Irrigation Peak Rewards program changes are listed as part of Case No. IPC-E-08-23 on the IPUC Web site, and are identified as Schedule 23 in both Idaho and Oregon.

Summary of Program Results

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

- In 2009, the program achieved a maximum peak load reduction of 160 MW.
- Three hundred seventy-four (374) customers, or 6% of the 6,379 eligible customers, chose to participate in the program.
- One thousand five hundred and twelve (1,512), or 8.6%, of the 17,621 eligible metered service points were enrolled in the program.
- Of the 1,512 enrolled service points, 382 were enrolled in the Timer Option, and 1,130 were enrolled in the Dispatch Option.
- The program achieved a total billing demand enrollment of 301,839 kilowatts (kW), of which 58,057 kW were enrolled in the Timer Option and 243,782 kW were enrolled in the Dispatch Option.
- The program costs as of October 31, 2009 were $9,636,796.
- Results show a 20-year average benefit cost (B/C) ratio of 1.54.
- Customer Satisfaction Survey results indicated that almost 90% of the responding participants were satisfied with the program.

Program Details

Timer Option

The pre-programmed Timer Option, offered previously, was made available to all irrigation customers. Installation fees between $250 and $500 were applied to participating service locations less than 75 Hp.

- Customers could choose to have all irrigation pumps on a single metered service point turned off on one, two, or three weekdays per week.

- Idaho Power determined the specific weekday or weekdays to schedule the interruption of all pumps at each service point.

- Interruptions occurred from 4 p.m. to 8 p.m.

Dispatch Option

The Dispatch Option allowed Idaho Power to initiate load control events that prevented pumps from operating at participating metered service points. Installation fees between $500 and $1,000 applied to participating service points less than 30 Hp. Customers could participate in one of three ways:

- Have a one-way communication device installed that allowed Idaho Power to control all the customer's pumps at a single metered service point.

- Have a two-way communication device installed that allowed both Idaho Power and the customer to control all the pumps at a single service point.

- Service points with multiple pumps and over 1,000 cumulative Hp were eligible to participate as a Large Service Location. Customers under this classification could choose to manually control which pumps were controlled during a load control event.

The parameters of the Dispatch Option, which limits the impact on customers, include the following:

- Idaho Power will initiate control (dispatch) events on a customized M2M Communications Web site.

- Dispatch load control events can occur any weekday, excluding July 4, between the hours of 2 p.m. and 8 p.m.

- Load control events can occur up to 4 hours per day and up to 15 hours per week, but no more than 60 hours per program season.

- Idaho Power will give notice by 4 p.m. the day prior to the initiation of a control event.

- If prior notice of a load control event has been sent, Idaho Power may choose to cancel the event by 1:30 p.m. on the scheduled day of the event.

- Idaho Power will give 30 minutes notice prior to start of all actual events and prior to the end of all actual events.

- The provisions for this program will not apply for any time Idaho Power interrupts the customer's load for a system emergency or any other time that a customer's service is interrupted by events outside the control of Idaho Power.

Program Incentives

A customer's incentive appeared as a bill credit that summed the demand credit and energy credit applied to a customer's monthly bills for the calendar months of June and July. The demand credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount for the interruption option selected by the customer. The energy credit is calculated by multiplying the monthly billing kilowatt-hour (kWh) usage by the energy-related incentive amount for the interruption option selected by the customer. Incentives offered are listed in Table 1.

Table 1. Option incentives.

Option	Demand Credit ($ per billing kW)		Energy Credit ($ per billing kWh)
Timer Option Incentives			
One Weekday	$3.15		
Two Weekdays	$4.65	plus	$0.002
Three Weekdays	$4.65	plus	$0.007
Dispatch Option Incentives			
	$4.65	plus	$0.031

All customer incentives participating in the Timer or Dispatch options are calculated using Idaho Power meter billing data. Idaho Power's Customer Information System (CIS) calculates the bill credits through contract riders. Installation fees and incentives for service points classified as Large Service Locations are completed through manual adjustments using interval meter data.

Program enrollment for 2009 was 1,512 service points across five geographic regions of Idaho Power's Idaho and Oregon service areas. Approximately 6,379 customers operated the 17,621 eligible service points. There were 750 potential Oregon customers and 5,629 potential Idaho customers.

Program Opt-out

During the 2009 irrigation season, one service point participant in the Timer Option and one service point participant in the Dispatch Option requested removal from the program. Both requests occurred after June 15. Under the program, if a service point is taken out of the Program after June 15, the participant is assessed a fee. The fee for each service point removed is $100 for the Timer Option and $500 for the Dispatch Option. This resulted in a total of $600, credited to the Energy Efficiency Rider (Rider) funding account to offset the initial program costs.

Under the rules of the Dispatch Option, participants have the ability to opt-out of dispatch events five times per service point. Each opt-out incurs a fee of $0.005 per kWh based in the current month's billing kWh, which may be prorated to correspond with the dates of program operation.

During the 2009 irrigation season, 24 services points opted out 38 times. These penalties were also credited to the Rider account.

Review of Program Results

Participation

During winter 2009, Idaho Power began program marketing strategies. Ten program workshops were sponsored across Idaho Power's service area, and Idaho Power staff participated in five agriculture shows. New program offerings were presented, and demonstrations of the new dispatch demand response option were provided.

In February 2009, over 6,000 customer mailings were sent to all eligible Idaho Power irrigation customers. The mailing included a program explanation, a program application, the program's incentive structure, a listing of the customer's eligible service points, and a potential incentive estimate for each program option based on the customer's 2008 usage. Additionally, one-on-one training with Idaho Power agriculture representatives familiarized customers with the new technology and program details.

Idaho Power experienced great interest in the program and installed all of the available control devices, which totaled 1,274 by the end of the season. Program participation exceeded the number of available devices. After July 31, 2009, when more devices became available, 51 additional devices were installed for customers desiring to participate in the program in 2010.

Figure 1 portrays Idaho Power's service area divided into five regional areas—Western, Canyon, Capital, Southern, and Eastern. These areas are used throughout this report in reference to program information.

Figure 1. Idaho Power service areas.

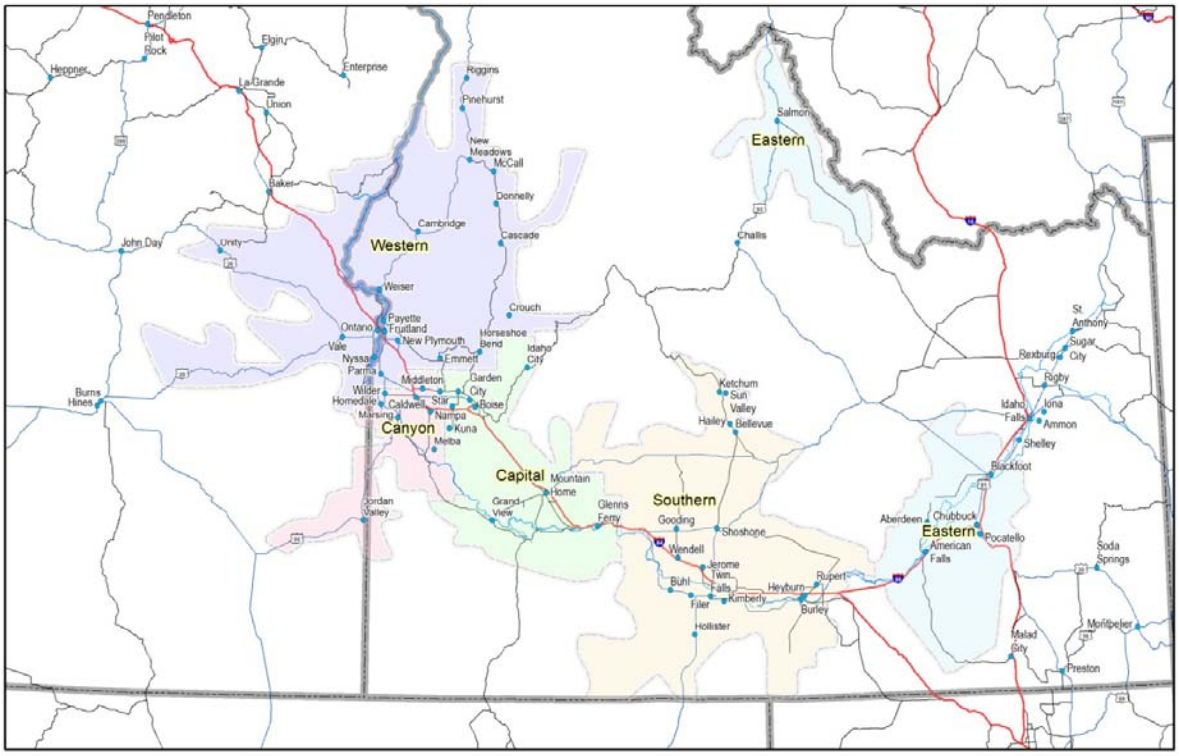


Figure 2 represents the 374 irrigation customers that operated the enrolled service points in the program and their distribution by Idaho Power's regional service areas.

Figure 2. Distribution of participants.

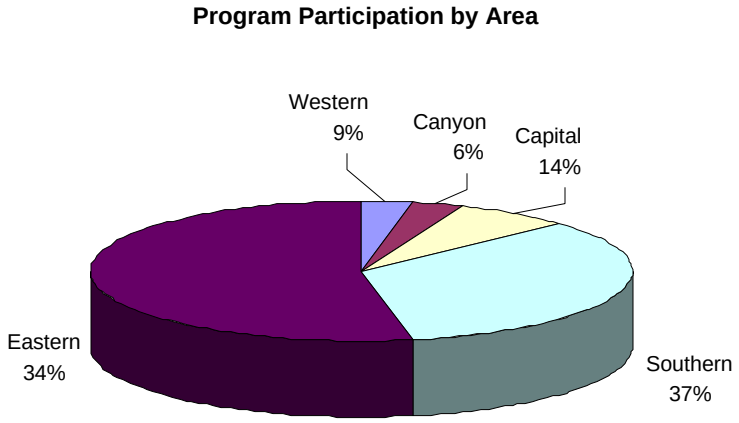


Table 2 lists the total number of eligible service points and the participation levels by area.

Table 2. Service points by area.

Idaho Power Area		Eligible Service Points	Service Points Enrolled	Enrolled Percentage by Area
Western		3,249	62 D[a]=50 T[b]=12	1.9%
Canyon		2,307	75 D=70 T=5	3.3%
Capital		1,584	148 D=129 T=19	9.3%
Southern	Twin Falls	4,975	263 D=223 T=40	5.3%
	Mini-Cassia	2,221	301 D=242 T=59	13.6%
Eastern		3,285	663 D=416 T=247	20.2%
Total Service Points		**17,621**	**1,512**	**8.6%**

[a] D= Enrolled in Dispatch Option

[b] T= Enrolled in Timer Option

Table 3 compares how the 1,512 participating service points were distributed among the different program options across Idaho Power's service area.

Table 3. Dispatch and Timer Options interruption distribution by service point.

		Dispatch Option			Timer Option			
					Interrupt Option 1	Interrupt Option 2	Interrupt Option 3	
Idaho Power Area		**Automatic Device**	**Manual[a]**	**Dispatch Total**	**1 Days/Week**	**2 Days/Week**	**3 Days/Week**	**Total Timers**
Western		50	0	**50**	1	1	10	**12**
Canyon		66	4	**70**	1	2	2	**5**
Capital		111	18	**129**	15	1	3	**19**
Southern	Twin Falls	220	3	**223**	12	19	9	**40**
	Mini-Cassia	242	0	**242**	50	2	7	**59**
Eastern		416	0	**416**	105	102	40	**247**
Total Service Points		**1,105**	**25**	**1,130**	**184**	**127**	**71**	**382**

[a]Large service locations (≥1000 Hp) selecting manual control.

Operations

Equipment and Monitoring

Timer Option

Electronic timers manufactured by Grasslin Controls Corp. (Model GMX-891-0-24) were used to interrupt power to 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.

To meet the load reduction targets of the program, Idaho Power tries to minimize interruption failures. Most of the electronic timers operated without incident with 21 (5.5%) of service points needing a follow-up visit by a contract electrician to resolve a problem prior to the program start date on June 15, 2009. All 382 service points participating in the Timer Option were checked and re-programmed for the 2009 irrigation season. While each known timer problem was resolved, a review of Idaho Power's load research data shows some issues went undetected and unreported by customers. These failures were due to mechanical and electrical problems. Idaho Power continues to address these issues through equipment monitoring and site visits.

Dispatch Option

M2M Communications was selected as the equipment provider, based on having the best equipment for the lowest price of the options Idaho Power researched. Currently, Idaho Power buys the equipment from M2M Communications and pays to have it installed on Idaho Power customers' pump panels.

Irrigation Load Control, LLC (ILC) formed as a joint venture between M2M Communications and Spartan Energy Control Systems to provide installation and service for Idaho Power. ILC's managing partners have a record of accomplishment of working together and have successfully implemented the Rocky Mountain Power Irrigation demand response program in 2008. Idaho Power initiates Irrigation Peak Rewards dispatch control events on a customized M2M Communications' Web site.

A Web-to-wireless remote control system, developed by M2M Communications utilized the Loadstar® Model M101control device installed in customers' pump motor control circuit to turn off or prevent the pump from running during an interruption event. This equipment provided remote cellular communication or remote satellite communication. The Web service allowed Idaho Power to dispatch interruption events on the days Idaho Power determined to be system peak days. Two-way communication from the device provided the feedback used by Idaho Power to determine the status of the customers' equipment surrounding an interruption event. Customers had the option of using the equipment for their own management purposes outside of interruption events and received a detailed user's guide.

The combination of M2M utilization of new hardware, software, and communications equipment, in addition to Idaho Power launching a new dispatch option, resulted in challenges described below. Idaho Power responded to the emerging challenges by working closely with

M2M to correct concerns in preparation for the 2010 season. No additional costs to the Rider or Idaho Power were incurred because of the solutions.

The Irrigation Peak Rewards dispatch load control system experienced a number of different issues that affected Idaho Power's ability to fully realize its load-shedding potential.

The system experienced highly inconsistent performance from load control devices equipped with satellite network communications. In spring 2009, the satellite company experienced problems properly placing a group of newly deployed communications satellites into their intended orbits. These problems resulted in the satellites operating on reduced power, which introduced gaps in coverage during which the dispatch load control devices could not communicate with any satellite. Performance inconsistencies were characterized by unpredictable latencies between the sending of dispatch commands to control units in the field and receipt of those commands by the field units. These latencies resulted in variable-length delays in shutting off irrigation pumps during load control events. In a few cases, issued commands did not reach the intended devices for more than one day.

In response to these satellite communication issues, prior to the load control season for 2010, all existing satellite-based dispatch load control devices will be replaced with similar devices that use a different satellite network.

Nearly all of the load control units were equipped with cellular radio modems. Several configurable operating parameters in these cellular modems were pre-programmed by M2M Communications during device manufacture. A significant number of these devices experienced events that caused the radios to be restored to their factory default values. The result was that the M2M Communications embedded firmware could no longer properly communicate with the cellular modem. An average of 24% of all devices did not provide any communication on whether or not they were functioning. The impact that this problem had on turning off pumps during power dispatches is unclear. Testing at M2M Communications showed that some of these devices could still receive and execute the commands to turn off pumps, but they could not call out to acknowledge and verify that the power had been controlled. A new version of embedded firmware was developed to correct this problem. As of November 2009, approximately 30% of the cellular-based units have received this firmware upgrade.

A small number of dispatch load control devices were wired incorrectly into the control circuit on the pump electrical service panel. This resulted in several cases where the load control device would operate properly, but the associated pump would continue to run. All such problem devices are believed to have been identified and the wiring corrected.

Various load control units experienced intermittent performance due to weak cell signal strength. A new, more stringent standard has been implemented that increases the minimum acceptable signal strength from –100 decibels (dB) to –95dB. Cell signal strength is being tested as part of the firmware upgrade process, and load control devices will be upgraded with high-gain antennas as necessary.

Table 4 provides a status summary of devices during each dispatch load control event, based on the total number of installed devices and status of the service point at the time of the dispatch event.

Table 4. Status of automatic control devices during dispatch events.

Status of automatic devices at the time of the dispatch event	Date of 2009 Dispatch Load Control Events						
	7/2/2009	**7/16/2009**	**7/17/2009**	**7/21/2009**	**7/22/2009**	**7/23/2009**	**7/27/2009**
Number of devices that did not record any communication	280	291	281	319	302	295	358
Number of devices that had communication but did not work	91	90	91	78	90	77	63
Number of devices that described pumps at service point as already off	352	344	370	310	368	379	384
Number of devices that described pumps at service point as manually turned off at beginning of dispatch event	87	99	108	65	73	73	97
Number of devices that turned pumps off	372	434	408	400	424	439	372
Total number of devices	**1,182**	**1,258**	**1,258**	**1,172**	**1,257**	**1,263**	**1,274**

Program Analysis

Load Reduction Analysis

While total load reductions from this program were impactful, determining exact amounts for each day was challenging. Load reduction impacts were determined by reviewing four different sets of data and past information contained in an impact analysis done by Summit Blue Consulting, LLC, in 2004. The four data sets reviewed and summarized in this section are M2M Communication data, Idaho Power Load Research data, Idaho Power sample substation data, and system load data. This information was used to determine realization rates to estimate load reduction achievement.

Realization rate is defined as the likelihood an irrigation service point is operating during the interrupt period and can represent program equipment failures, which is used to determine program impacts. The realization rate can be characterized as the percentage of monthly billing demand expected to result in an actual load reduction on the system during a given interruption

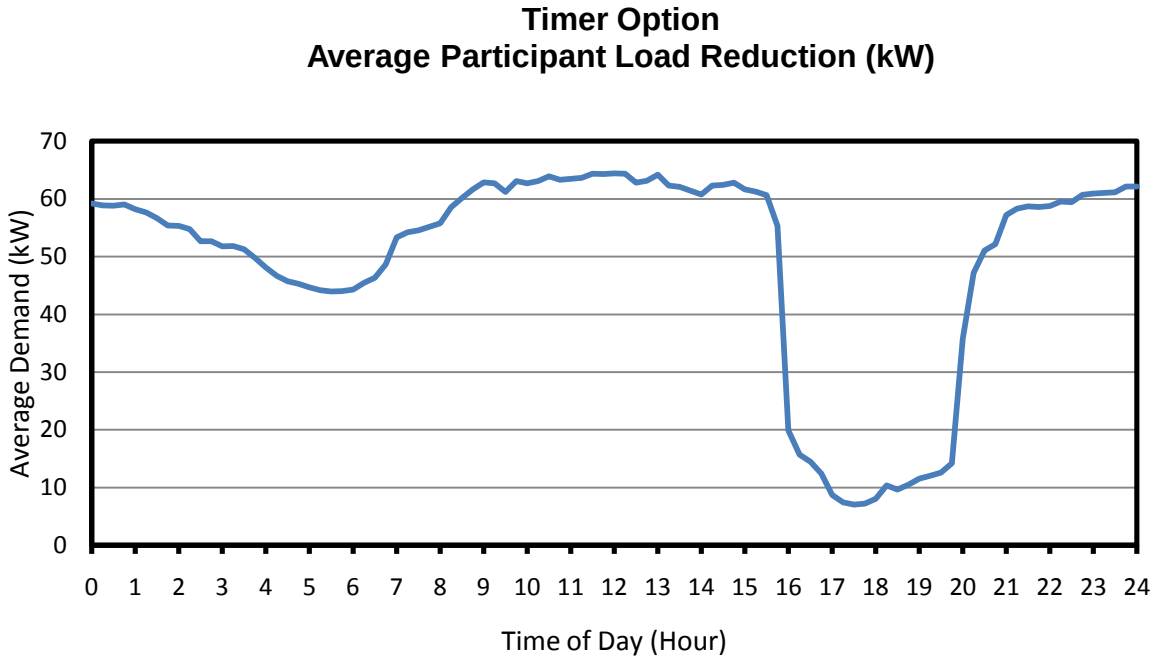
period. This rate is highest at the end of June and the beginning of July when many irrigation pumps are operating nearly 24x7. The realization rate is lower later in the irrigation season when many irrigation pumps are turned off due to crop maturity.

Load Research Analysis—Timer Option

Each year Idaho Power reviews the realization rates, from the impact evaluation prepared by Summit Blue Consulting, LLC, through analysis of current load research data. This year, Idaho Power had 16, 15-minute interval load research service points in the Timer Option.

Figure 3 shows the average hourly kW for all days in July and shows the average load reduction per participating metered service point under the Timer Option within the load research sample. The graphed data represents the average demand (kW) for all interrupt days in 2009.

Figure 3. Average metered demand (kW) Timer Option.



Analysis of the data used to create this graph results in an average 63 kW before the events and 9 kW during the events. When compared to the average billing demand of 139 kW for these service points, the analysis yields an estimated 39% reduction because of the timers. This is the lowest percentage Idaho Power has achieved for the Timer Option. Further analysis indicated this was caused primarily by the extremely low realization rate (6%) in the second half of June. The rate was impacted by the high amounts of rain across Idaho Power's service area in late June. Based on these analyses, Idaho Power believes the realization rates from the impact evaluation continue to be a reliable and accurate means to estimate the program's load reduction for Timer Option participants. Table 5 shows the program evaluation results from Summit Blue Consulting, LLC's impact evaluation for each two-week period applicable to the 2009 program season.

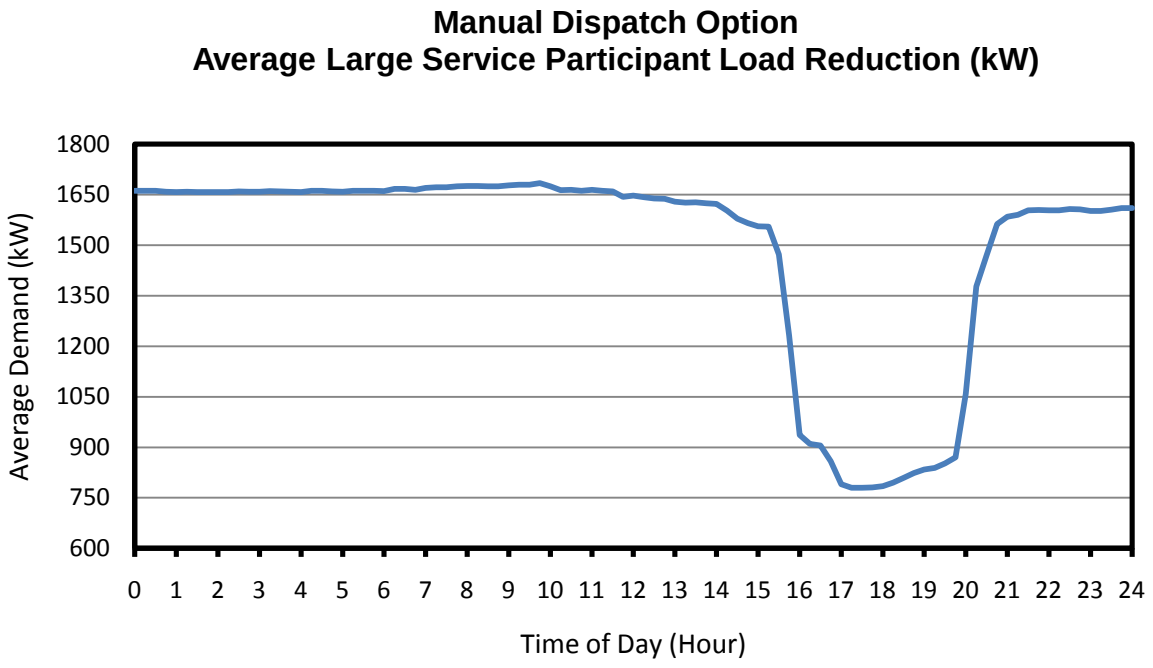
Table 5. Realization rates by period for Timer Option participants.

Period	Idaho Power Realization Rate
2nd half of June	64%
1st half of July	60%
2nd half of July	53%
Average	**59%**

Load Research Analysis—Manual Dispatch Option

For the Manual Dispatch Option, Idaho Power used 15-minute load research interval data from each of the 25 participants to determine the amount of load reduced. Figure 4 displays the average hourly kW for all days in July and shows the average load reduction per participating metered service point under the Manual Dispatch Option. The graphed data represents the average demand (kW) for all interrupt days in 2009.

Figure 4. Average metered demand (kW) Manual Dispatch Option.



Analysis of the data used to create this graph results in an average of 1,646 kW before the events and 812 kW during the events. When compared to average billing demand of 2,765 kW, the analysis results in an estimated 30% reduction by this group of customers for all events in 2009. The 30% is an expected number for this group because they were able to leave pumps on during events. Because this data represents all service locations in this group, the load reduction calculation for this group is easily obtained.

Load Research Analysis—Automatic Dispatch Option

The Automatic Dispatch Option represents the rest of the program participation. This was the largest participation group with 1,105 service points enrolled. Idaho Power had 15-minute load research meters on 54 service points throughout this group.

Figure 5 shows the average hourly kW for the days in July when the load was dispatched at the same time from 4:00 p.m. through 8:00 p.m. It also shows the average load reduction per participating metered service point under the Automatic Dispatch Option.

Figure 5. Average metered demand (kW) Dispatch Option for July 2, 16, and 17.

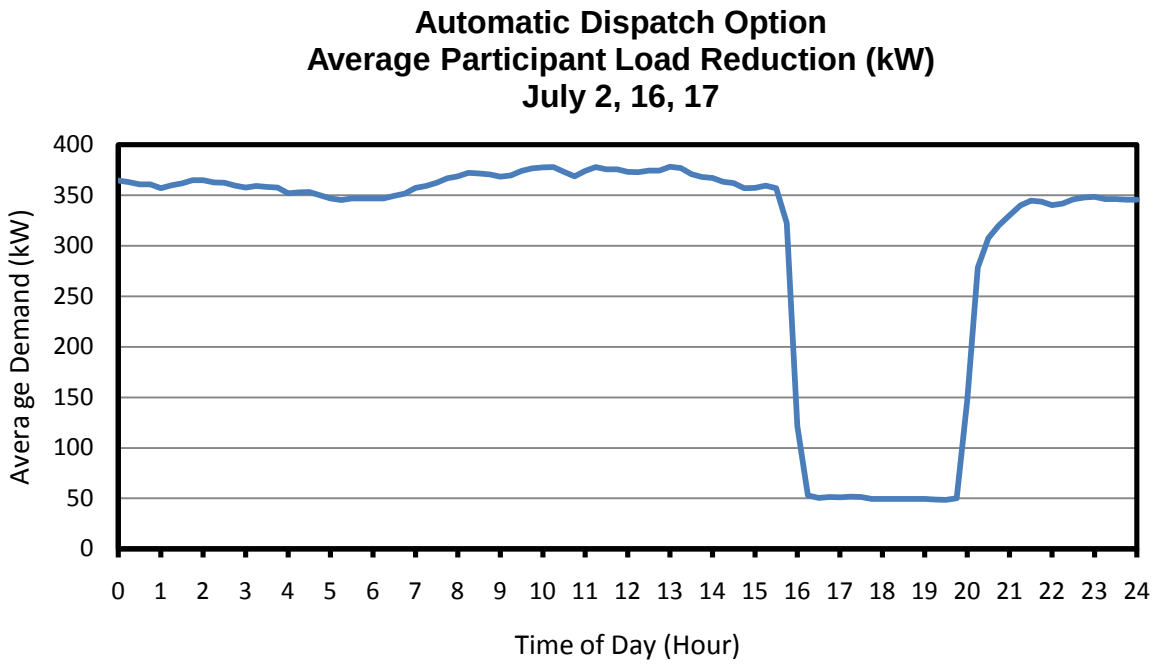
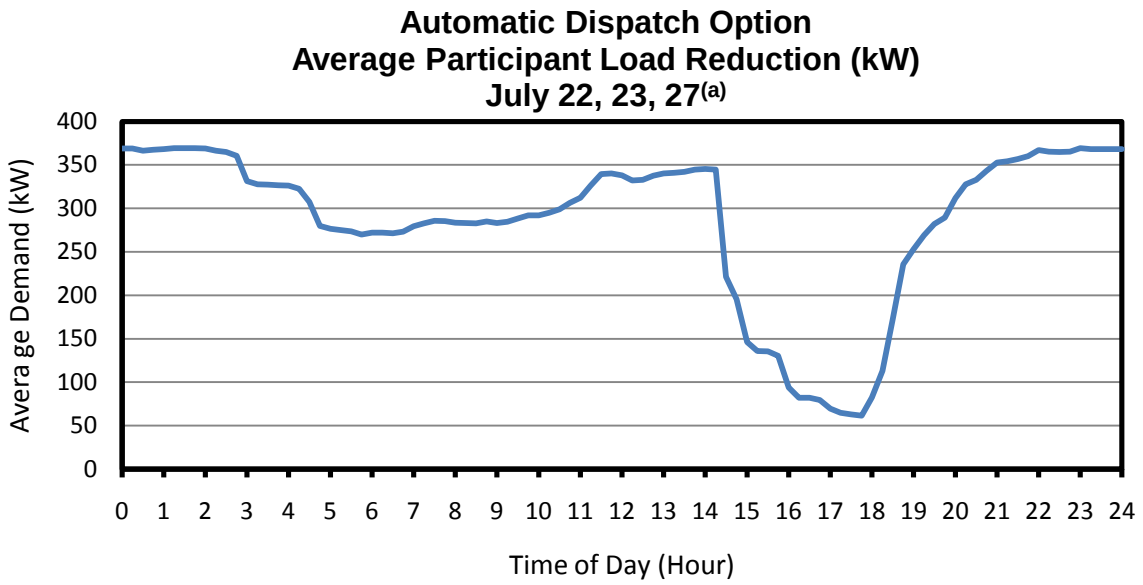


Figure 6 shows the average hourly kW for the days in July when the program was dispatched in two staggered blocks from 2:30 p.m. through 6:30 p.m. and 4:00 p.m. through 8:00 p.m. It also shows the average load reduction per participating metered service point under the Dispatch Option.

Figure 6. Average metered demand (kW) Dispatch Option for July 22, 23, and 27.



[a]July 21 was omitted because it was dispatched at a different time and did not include the Canyon area.

Analysis of the data used to create the prior two graphs result in an average 347 kW before the events and 63 kW during the events. When compared to average billing demand of 474 kW, the analysis results in an estimated 60% reduction by this group of customers for all events in 2009.

M2M Communications Device Analysis—Automatic Dispatch Option

For the Automatic Dispatch Option, Idaho Power also used device communication data from M2M Communications. A complete log of the operational data for each automatic device was analyzed for each day a dispatch event occurred.

The realization rates determined in Table 6 show the number of control devices that were turned off during each dispatch event in 2009. The analysis of this data resulted in an average realization rate of 40% for all events. This low realization rate is primarily a result of issues already described.

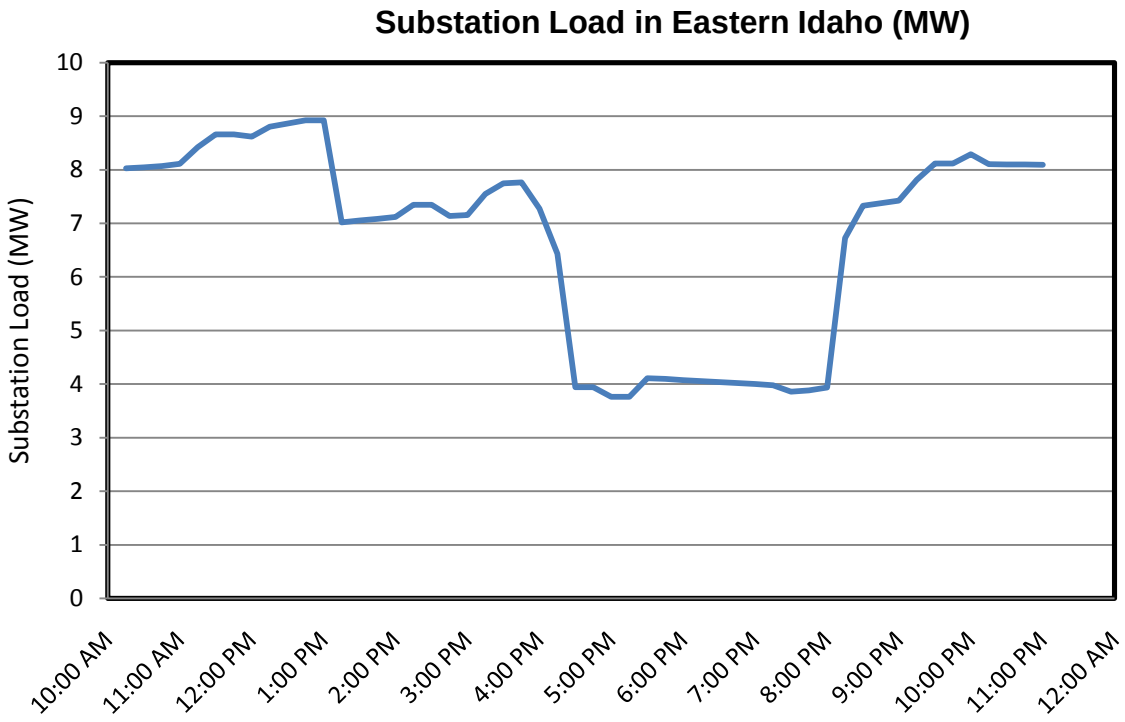
Table 6. Realized rate of automatic devices that turned off during load control dispatch events.

Status of automatic devices at the time of the dispatch event	Date of 2009 Dispatch Load Control Events						
	7/2/2009	7/16/2009	7/17/2009	7/21/2009	7/22/2009	7/23/2009	7/27/2009
Total number of devices that turned off for the dispatch event	459	533	516	465	497	512	469
Total number of devices	1,182	1,258	1,258	1,172	1,257	1,263	1,274
Realization rate	39%	42%	41%	40%	40%	41%	37%

Substation Data Analysis

An additional way in which Idaho Power chose to calculate the potential load reduction from the program was to analyze specific substation data where there were substantial numbers of participants in the program. As an example, Figure 7 describes the load data on the event day of July 16 from a particular substation in the Eastern area in which there were 30 participants with a total billing demand of 5.6 MW.

Figure 7. Load data from a particular substation in the Eastern area on July 16.



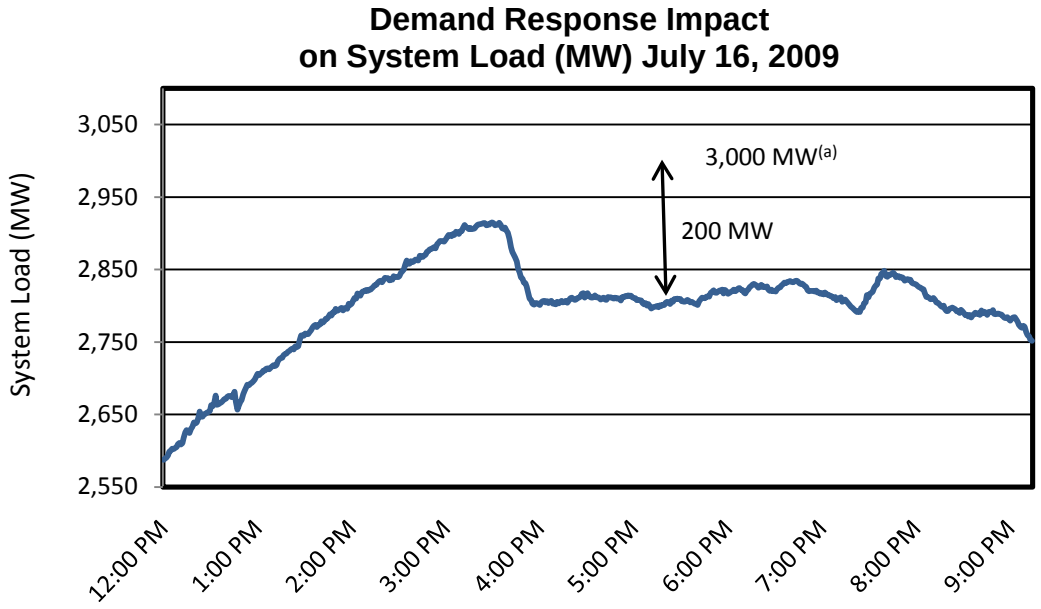
The data represents 7.9 MW of load before the event and 4 MW during the event, which equates to a total load reduction of 3.9 MW. When compared to the total billing demand of program participants on this particular substation, Idaho Power calculated a realization rate of 66%.

System Load Data Analysis

Another way to view the total 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 in the afternoon.

Figure 8 represents demand response impact to the entire Idaho Power system firm load on July 16, 2009. On this date, load control events were initiated using the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs. Interruptions occurred from 4:00 p.m. through 8:00 p.m. at participating service locations in all regions under the irrigation Dispatch Option, the Timer Option, and the FlexPeak Management program. The A/C Cool Credit program interruptions occurred from 4:00 p.m. through 7:00 p.m. Based on the current day forecast, it was estimated that loads would have reached 200 MW higher than the actual loads at peak hour. Using this information, the calculated load reduction attributable to Irrigation Peak Rewards is estimated to be 162 MW, which results in an overall program realization rate of 47%.

Figure 8. Total system load on July 16.



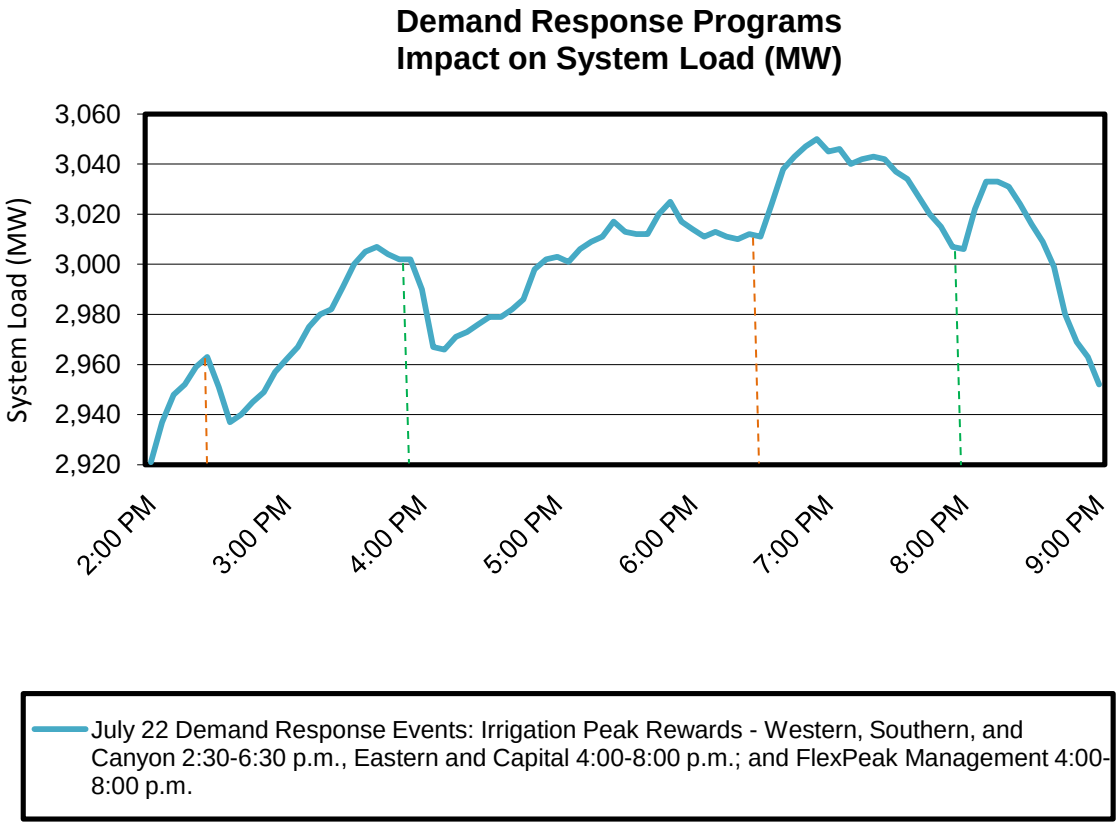
[a]Estimated system load with no demand response.

After observing the impact that the control event days of July 2, 16, and 17 had on Idaho Power's total system load during the traditional hours of 4:00 p.m. and 8:00 p.m., the company decided to modify the dispatch procedure slightly to improve the effectiveness of the program. Simultaneously turning off all pumps enrolled in the Dispatch Option created the problem of

moving the peak time to outside of the 4 p.m. to 8 p.m. period. To resolve this problem, the Dispatch Option participants were grouped to allow Idaho Power to turn off approximately half of the pumps between 2:30 p.m. and 6:30 p.m. and the other half of the pumps between 4:00 p.m. and 8:00 p.m. This spread the dispatched load reduction over a longer period, but provided one and one-half hours of overlap in which both groups were dispatched during the time Idaho Power typically experiences its highest system loads.

Figure 9 represents demand response impact to the entire Idaho Power system firm load on July 22, 2009. On this date, load control events were initiated using the Irrigation Peak Rewards program and FlexPeak Management program. Under the irrigation dispatch option, participating service locations in the Southern, Western, and Canyon areas were interrupted from 2:30 p.m. through 6:30 p.m. The Capital and Eastern areas, the Timer Option, and the FlexPeak Management program interruptions were interrupted from 4:00 p.m. through 8:00 p.m.

Figure 9. Demand response impact on Idaho Power system firm load.



Figures 10 and 11 demonstrate the program's impact on system firm load for all irrigation demand response events initiated in 2009. Figure 10 depicts the impacts on days when load

control events were called from 4:00 p.m. to 8:00 p.m., while Figure 11 includes days when events occurred from 2:30 p.m. to 6:30 p.m.

Figure 10. Demand response program impact on system load early- to mid-July.

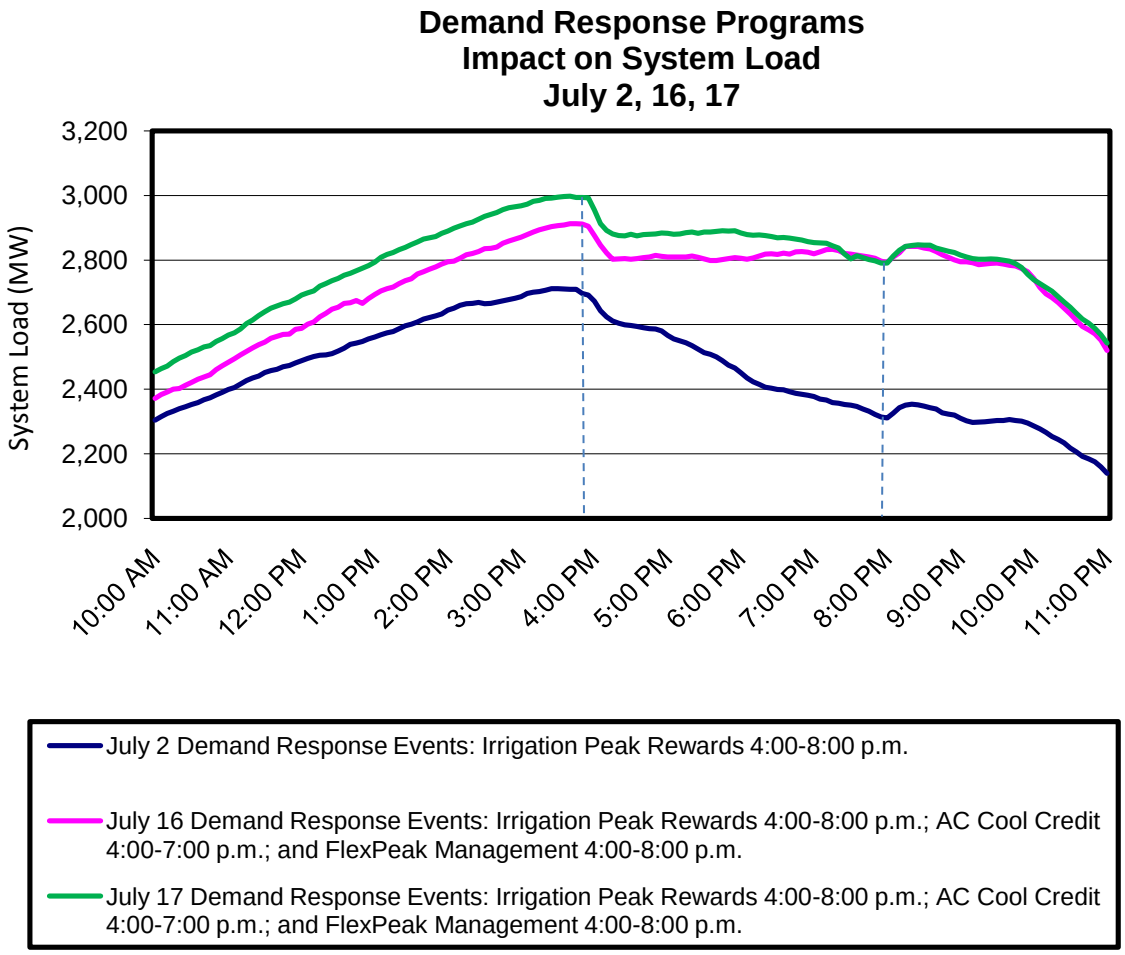
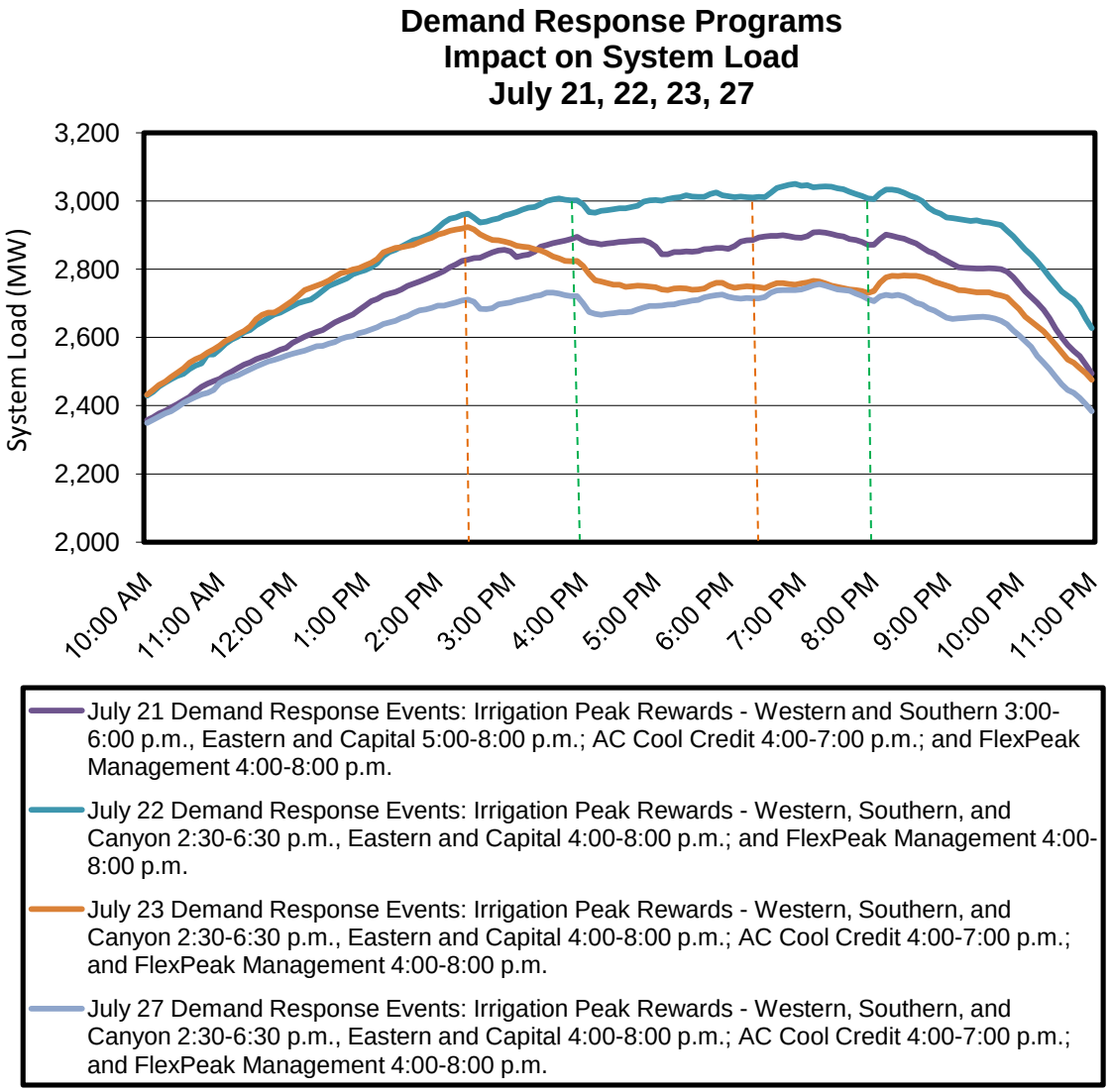


Figure 11. Demand response programs impact on system load late July.



After reviewing the results from each different method used to analyze load reduction, Idaho Power concluded that the substation data, load research data, and system load data all resulted in a similar realization rate for July 16. Idaho Power chose to use the realization rates calculated from load research data to determine program load reduction. These results are described in the following section.

Load Reduction Achieved

Idaho Power attempted to distribute the Timer Option participating service points evenly throughout each weekday, based on cumulative load reduction potential. However, due to service point size variability, enrollment requests by customers, enrollment opt-outs, and other variables,

the load cannot be exactly balanced. All participants in the Dispatch Option were grouped into five areas to be dispatched on each scheduled event day.

Peak billing demand data for the months of June and July 2008 were used to estimate the amount of load enrolled in the program. The total billing demand enrolled in the program was 301,839 kW. Table 7 shows how the enrolled load was distributed by area.

Table 7. Enrolled billing demand by region (kW).

		Timer Option (1,2,3)[a]			Dispatch Option[a]		
Idaho Power Area		**1 Days/Week**	**2 Days/Week**	**3 Days/Week**	**Automatic Dispatch Option**	**Manual Dispatch Option**	**Total All Options**
Western		79	88	532	12,301	0	13,000
Canyon		20	221	248	7,323	10,748	18,560
Capital		2,673	79	353	20,823	50,777	74,705
Southern	Twin Falls	1,902	2,937	718	23,752	2,311	31,620
	Mini-Cassia	9,758	424	1,009	51,900	0	63,091
Eastern		17,078	15,810	4,128	63,847	0	100,863
	Total kW	**31,510**	**19,559**	**6,988**	**179,946**	**63,836**	**301,839**

[a]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 8 indicates the realization rates Idaho Power used to determine the load reduction for each day of the summer 2009. As previously described, Idaho Power uses the realization rates from Summit Blue Consulting, LLC, for the Timer Option. However, due to extremely wet weather in June, Idaho Power's load research data analysis resulted in a lower realization rate of 6% in the second half of June. Therefore, Idaho Power applied this realization rate for this time period.

Table 8. Realization rates used for program options.

Period	Timer Options	Automatic Dispatch Option	Manual Dispatch Option
2nd half of June	6%	N/A	N/A
1st half of July	60%	62%	29%
2nd half of July	53%	60%	30%

Table 9 shows the MW reduction achieved daily on a week-by-week basis.

Table 9. Total program daily MW reduction using realization rates.

	Mon	Tue	Wed	Thur	Fri
June 15–19	1.3	1.2	1.3	1.3	1.2
June 22–26	1.3	1.2	1.3	1.3	1.2
June 29–July3	12.6	12.1	12.6	160.2[(a)]	11.6
July 6–10	12.6	12.1	12.6	13.2	11.6
July 13–17	12.6	12.1	12.6	155.3	153.8
July 20–24	11.2	145.8	154.8	155.3	10.2
July 27–31	154.8	10.7	11.1	11.6	10.2

[(a)]Shaded cells are days when dispatch events occurred

Cost-Effectiveness

Program Costs

This program had a total cost of $9.63 million, with customer incentives and device installation the largest two expenditures. Customer incentives were 71% of the total costs. In future years, when previously installed devices are utilized, the customer incentive will make up a larger percentage of the overall costs. Customers participating in the Irrigation Peak Rewards program realized an average annual bill savings of 22% on each service point enrolled. Customers enrolled in the Timer Option realized an average annual bill savings of 10%, and Dispatch Option customers realized a 27% savings. The average incentive on a per-Hp basis across all options was $16.50. Table 10 displays the annual program costs as of October 31, 2009. Program costs remain consistent on a year-to-year basis.

Table 10. Annual program costs.

Item	Program Costs
Materials and Equipment	$972,073
Installation and Contract Services	$1,695,611
Incentive payments	$6,826,581
Marketing and Administration	$142,531
Total	**$9,636,796**

Benefit-Cost Analysis

The B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model that uses financial and DSM alternative costs assumptions from *Appendix D—Technical Appendix* for the *2006 Integrated Resource Plan* (IRP). As published in the 2006 IRP, for peaking alternatives, such as demand response programs, 162 MW simple cycle combustion turbine is used as a cost basis. The levelized capacity cost factors applied are $64.92/kW/yr. The benefit for shifted energy use in the Irrigation Peak Rewards program is calculated using demand-side management

(DSM) alternative energy costs as determined by Idaho Power's Power Supply model, AURORAxmp® and published in the 2006 IRP. Idaho Power's cost-effectiveness model for the Irrigation Peak Rewards program is updated annually with actual benefits and costs. In 2009, the updating of the cost-effectiveness model resulted in a utility B/C ratio of 1.54. For demand response programs, the utility cost test is the most relevant B/C analysis. For the Irrigation Peak Rewards program and other demand response programs, the participants have little or no cost. The majority of the costs (Table 9) are the incentive payments made by the utility, and almost all other expenses are incurred by the utility. The benefits are based on peak reduction and shifted energy use.

Table 11 summarizes the inputs that were used in the cost-effectiveness model. In 2009, the program results yielded a 20-year average B/C ratio of 1.54.

Table 11. Benefit-cost model inputs.

Description	Input
Number of metered service points	1,512
Overall program realization rate for July	49%
Average service point, billing kW (peak month)	200
Enrolled peak (kW)	301,839
Average July peak reduction (MW)[a]	154
Actual Program Cost (as of Oct. 31, 2009)	**$9,636,796**

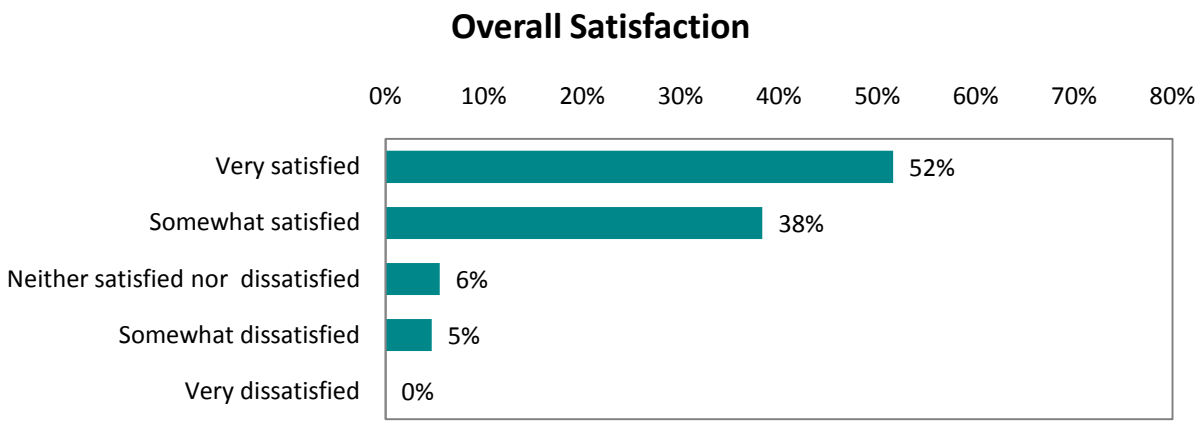
[a]Dispatch days only.

Customer Satisfaction Survey Results

Idaho Power conducted a customer satisfaction survey, *Idaho Power Peak Rewards Program Follow-up Survey*, from November 4 to November 19, 2009. The purpose of the survey was to solicit feedback regarding the program. The ten-question survey was mailed to all 374 irrigators enrolled in the Irrigation Peak Rewards program during summer 2009. During the two-week period, 129 participants responded, yielding a 34% response rate.

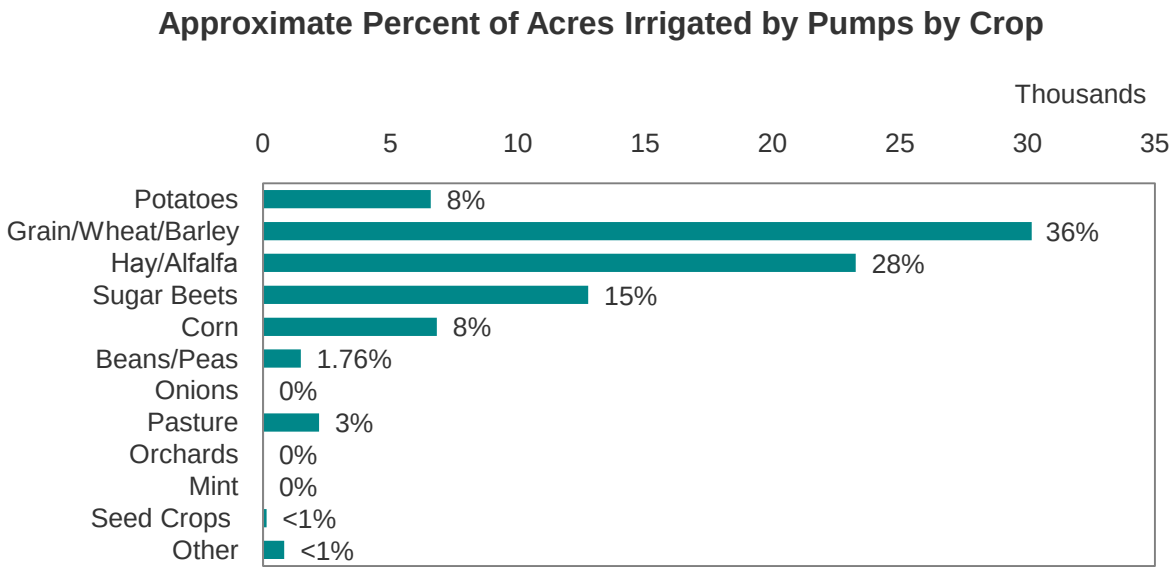
Figure 12 indicates the percentage of overall satisfaction with the program by participant responses. Almost 90% of the responding participants were either very satisfied or somewhat satisfied with the program. Nearly 5% of the respondents indicated dissatisfaction with the program, for a variety of reasons related to details of program operation and other considerations.

Figure 12. Overall satisfaction with Irrigation Peak Rewards program.



The 129 respondents reported approximately 84,257 acres of crops under irrigation. Acreages of grain, wheat, and barley accounted for an estimated 30,166 acres, or 36%. Conversely, there were slightly more farmers indicating hay and alfalfa as a crop in the program, though the total acreage was 23,261 estimated acres, or 28% of the irrigated acreage in the program. This data is usable by Idaho Power in marketing the program to customers who are unsure of whether they can implement the program for the crops they grow. Figure 13 details type of crops irrigated by pumps and approximate percent of acres reported.

Figure 13. Approximate percent of acres irrigated by pumps by crop.



The respondents' perceived level of information provided by the electrician installing the pump technology is indicated in Figure 14. Of the responding participants, nearly 50% indicated that the electrician involved in the installation provided adequate information, while 20% indicated the electrician provided some, but not enough, information. A reason for these perceptions was

possibly due to the work volume of the electricians installing a large amount of devices in a short time frame. Idaho Power plans on working closely with the ILC to improve customer communications during installation in the future.

Figure 14. Information provided by the electrician.

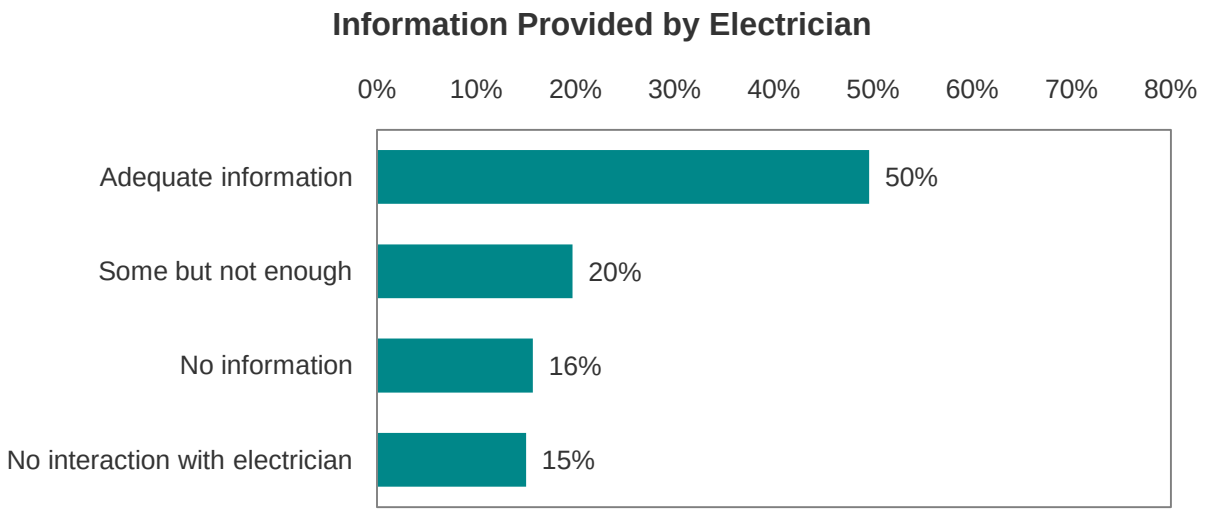
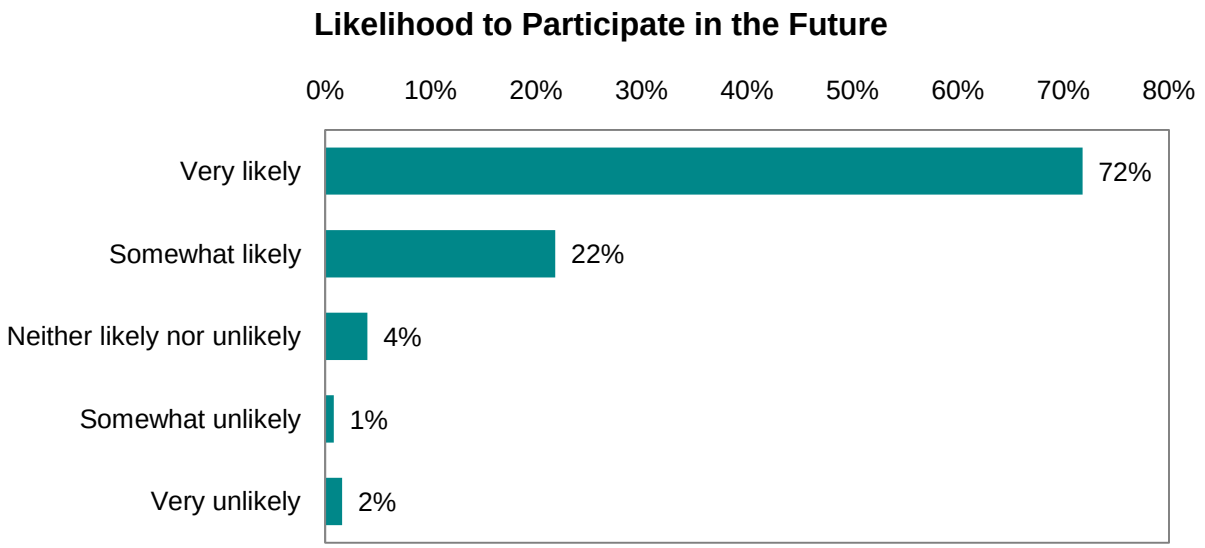


Figure 15 displays respondents' likelihood to participate in the Irrigation Peak Rewards program in the future by percentage. Approximately 94% of the respondents indicated they were either very likely or somewhat likely to participate in the Irrigation Peak Rewards program in the future. Idaho Power plans to increase electrician and customer training in 2010 to address the results.

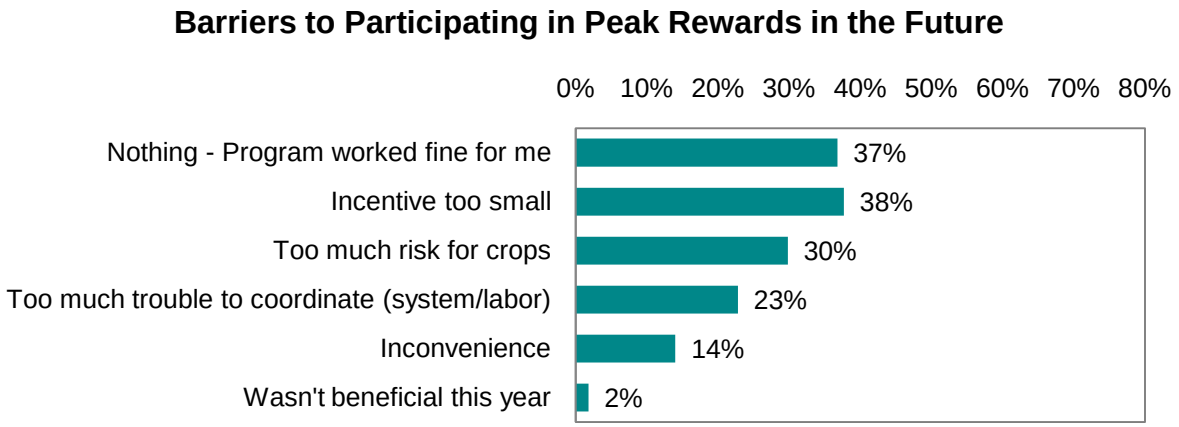
Figure 15. Likelihood to participate in the Irrigation Peak Rewards program in the future.



Barriers to participating in the Irrigation Peak Rewards program in the future were addressed in the study. Respondents' barriers by percentage are listed in Figure 16. When provided a list of potential reasons that might prevent them from participating in the program in the future, almost 37% indicated the program worked fine. Nearly 38% indicated the incentive was too small, 30% indicated too much risk for crops, almost 23% indicated too much trouble to coordinate, and 14% indicated it was inconvenient.

Idaho Power continues to evaluate this program and the potential incentive levels by using the overall costs of the program and comparing them to the capacity costs and shifted energy costs as published in the *Appendix D—Technical Appendix* for the 2006 IRP. The incentive level is a major factor when irrigators consider program participation and is balanced with offering a cost-effective program, thus the current incentive levels are near the maximum allowable amount while maintaining a cost-effective program.

Figure 16. Barriers to participating in the Irrigation Peak Rewards program in the future.



Lastly, more than 55% of the respondents indicated they also participated in Idaho Power's Irrigation Efficiency Program, and almost 39% of the respondents had attended an Idaho Power workshop during winter 2009.

Conclusions

- The Irrigation Peak Rewards program, which included the new Dispatch Option, increased participation and allowed Idaho Power to achieve greater load reductions.
- Idaho Power plans to continue the program because it is a cost-effective way to reduce peak demand on Idaho Power's electrical system at the optimal time of day.
- The combined Timer and Dispatch Options of the program achieved a maximum peak load reduction of 160 MW on July 2, at the generation level.

- Irrigation customers make significant contributions to Idaho Power's demand response programs.
- Customer Satisfaction Survey results indicated that approximately 94% of the respondents indicated they were likely to participate in the Irrigation Peak Rewards program in the future.