THE CADMUS GROUP, INC.

Date: March 24, 2011

To: Jeff Bumgarner

From: Jim Stewart, Hossein Haeri and Brian Hedman

Re: Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program

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Rocky Mountain Power retained The Cadmus Group to evaluate the 2009 and 2010 demand impacts of the company's irrigation load control program offered to the customers in Idaho. This document summarizes the results of Cadmus's study.

Background

In 2009, the Program enrolled 2,032 customers and had approximately 260 MW of participating load in Schedule 72 (schedule forward) and Schedule 72A (option dispatch). In 2010, the Program enrolled 1,975 customers and had approximately 283 MW of participating load. In both years, over 98 percent of the Program load was enrolled through the dispatch option.

During the 2008 Program Season the Company began noticing voltage excursions outside industry acceptable standards during dispatch events. In 2010 the Company implemented a process to reduce load and return load to normal operating levels in phases to minimize the impact on the company's transmission and distribution system. As a result, the Company was still unable to take the entire participating load off during the peak time period between 2:00p and 6:00p. As a consequence, the current level of participation is beyond what RMP can effectively dispatch. This has reduced the Program's cost-effectiveness.

Technical Approach

The Cadmus Group estimated the hourly load reductions achieved by the Program in 2009 and 2010. The analysis was conducted using SCADA system data for five sub-stations (Amps, Big Grassey, Bonneville, Jefferson, and Rigby) that accounted for most (77 percent) of the controlled irrigation load in Idaho. For each substation and event hour, Cadmus estimated a reference load, what the load would have been in the absence of the event, and compared it to the observed load during curtailment events. Results were extrapolated as representative of the remaining circuits to account for total program loads.

The reference load for an event hour was estimated in two ways: (1) as the unconditional average load in the same hour of the two weekdays preceding and following the event; and (2) as the conditional average load estimated using a regression of hourly demand on weather, calendar and time effects, and indicators for event hours and hours preceding and following the event. The difference between the observed load and the actual yielded the estimate of the load reduction in the event hour.

For both estimation approaches, the estimated load reduction in each hour was compared to the expected load reduction (nominal load reduction) adjusted for opt-outs and a load reduction realization rate was calculated. There are several aspects of this methodology that are worth noting before considering the results. Nominal load is defined as the sum of customers' average billing demands for June, July and August for the two prior years.

- The impact analysis is based on SCADA data at the substation level. Since the majority of the loads being served by these substations consist of irrigation, the amount of "noise" in the data resulting from the variability of non-irrigation loads is expected to be minimal. Moreover, the hourly demand model used to estimate the load impacts largely accounts for such noise in the substation data.[1]

- Program management staggers (stair-steps) the dispatching of loads at the beginning and end of events for grid reliability purposes. The hourly analysis of loads does not account for the staggering. As a result, the estimated load impacts in the first and last hours are an estimate of the average load reduction over the hour and may not represent the true reduction at the beginning (likely to be smaller than estimated) or end of the hour (likely to be larger).

- The analysis adjusts for, in the calculation of realization rate, the required scheduling of 22 percent of the available participating loads outside of the 2:00p-6:00p time period. This scheduling restriction was implemented in 2010 to accommodate the Grid control voltage limitations previously noted. While this did not impact realization rates, it did impact the decrease in aggregate reduction from 205 MW in 2009 to 156 MW in 2010.

Results Summary and Conclusions

With these limitations in mind, the evaluation team analyzed the substation data for the 2:00p to 6:00p time horizon and reached the following conclusions:

- In 2009, the maximum hourly load reduction on the five substations was 158 MW which extrapolates to 205 MW for the entire program. This reduction occurred on July 17 and represented 86 percent of the nominal load (program resources) adjusted for opt-outs in the hour. The realization rates, which show how much load was shed relative to expectation, ranged from a low of 17 percent on August 5 to the July 17 high of 86 percent. In 2010, the maximum hourly load reduction at the five substations was 120

[1] Of the five substations only the Rigby substation serves other loads, including small businesses, a college, a hospital and the cities of Rexburg, Rigby, Ririe, Menan, and smaller towns.

MW which extrapolates to 156 MW for all Idaho irrigation program loads. This occurred on July 8 and represented 77 percent of the opt-out-adjusted nominal load in the hour. Program benefits are calculated based on 156 MW of system impact. On July 20, a load reduction of 120 MW resulted in the maximum realization rate of 82 percent. During hours when events are traditionally called, realization rates ranged from a low of 29 percent on August 24 to the high of 82 percent on July 20.

- Realization rates were calculated based on expected loads, or in the case of the Rocky Mountain Program, loads that could safely be dispatched without adversely impacting line voltages. This is an important distinction worth noting. Had the calculation of realization rates been based on total participating loads, this would have resulted in lower realization rates. As program cost-effectiveness is calculated on actual load reductions relative to a program's costs (rather than a realization rate), realizations rates should not be considered the definitive measurement of a program's effectiveness and value.

- The load reductions and realization rates in any year may not be representative of typical load impacts the program might achieve because of annual weather-related variations in irrigation demand.

- Rocky Mountain Power system peak coincides with hours when events are traditionally called (hours 2:00p to 6:00p). In 2009, all of the top 10 non-event, summer hours occurred during the traditional event window. Rocky Mountain Power system peak hours do not coincide with morning and early afternoon / evening hours when loads were dispatched in 2010 because of transmission and distribution constraints.

- While the Program has been operationally effective, it has not been as cost-effective as it could be. In 2009 and 2010, the Program enrolled more load on some substations than it could dispatch during peak hours because of transmission and distribution constraints. To increase future cost-effectiveness, RMP needs to either upgrade its transmission and distribution system in Idaho to remove the operating constraints or limit enrollment in the Program to a level consistent with the system's ability to dispatch resources during peak hours.

In addition, since the inception of the program Rocky Mountain Power has been educating irrigators about efficient irrigation practices and the benefits of irrigating during off-peak hours. Rocky Mountain Power estimates that because of education irrigators have shifted between 5 and 7 percent of their loads between 2:00p and 6:00p to off peak. The estimation of the reference load for this analysis is not taken into consideration in this analysis. If the benefits from education were taken into consideration the load shifting from education would have the effect of further improving measured impact or realization rate.

Objectives

The objectives of this evaluation were:

- To estimate the irrigation load reductions from Rocky Mountain Power's irrigation direct load control program in 2009 and 2010.
- To estimate *ex-post* realization rates, the ratio of the *ex-post* impacts to the nominal program loads that can be shed.

Program Operations

RMP operates two irrigation load control programs in Idaho. The first is "schedule forward" (Schedule 72) and involves direct control of irrigation loads on a scheduled basis. Enrollment in this program has been decreasing annually with the implementation of the dispatch program option. In July 2009, there were 4.1 MWs of nominal load in this program. The second is the dispatch option (Schedule 72a). RMP calls "events" with 24 hours advance notice and uses simplex technology to shed irrigation loads during event hours (a maximum of four hours per day per customer during weekdays).[2] The event hours are typically between 2:00p to 6:00p. In July of 2009, there were 254 MWs of nominal irrigation load in both programs. In July of 2010, there were 282 MWs of nominal load.

Event History

In 2009, RMP called six events that each lasted four hours. The events occurred between 2:00p and 6:00p. Table 1 shows the dates and hours of the events.

Table 1. Event Days and Hours in 2009

Idaho 2009	
30-Jun	4 hours
17-Jul	4 hours
23-Jul	4 hours
3-Aug	4 hours
5-Aug	4 hours
13-Aug	4 hours
Hours for all events occurred during hours 2:00p to 6:00p.	

In 2010, RMP called 11 events, excluding three one-hour events in early June and one four-hour event for irrigators served by the Big Grassey substation and for grid operations purposes.[3] In addition to a larger number of events in 2010, there were also a larger number of hours when

[2] Participants may opt out of a maximum of five events per season.

[3] The regression models control for the grid operations events, but we do not report the estimated load reductions.

RMP dispatched program resources. Resources were dispatched during not just 2:00p-6:00p but also hours before and after this window because of transmission and distribution constraints. Table 2 shows the dates and number of hours for the 2010 events.

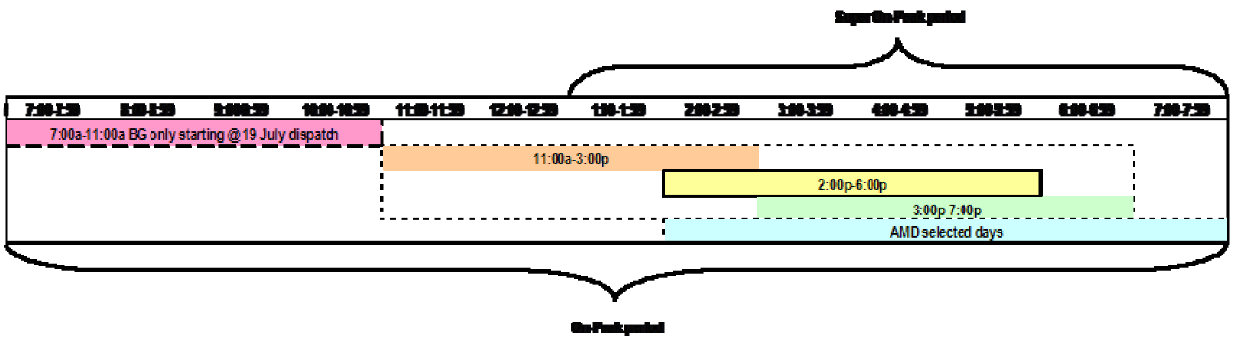
Table 2. Event Days and Hours in 2010

Idaho 2010	
29-Jun	8 hours*
8-Jul	8 hours*
15-Jul	8 hours*
16-Jul	8 hours*
19-Jul	12 hours**
20-Jul	12 hours**
26-Jul	12 hours**
2-Aug	12 hours**
5-Aug	12 hours**
24-Aug	12 hours**
26-Aug	12 hours**

*Hours for all substations: 11:00a -7:00p.
** For all substations except Big Grassey, event hours occurred 11:00a – 7:00p. Beginning July 19, RMP also dispatched Big Grassey customer loads from 7:00a - 11:00a.

Between the first event on June 29, 2010 and the fourth event on July 16, 2010, RMP dispatched program resources on event days in three blocks over eight hours: 11:00a –3:00p, 2:00p – 6:00p, and 3:00p–7:00p. Figure 1 illustrates the dispatch of program resources during these time blocks.

Figure 1. Summer 2010 Irrigation Direct Load Control Dispatch Blocks



Beginning with the fifth event on July 19 and ending with the final (11th) event on August 26, RMP dispatched additional resources between 7 am and 11 am on the Big Grassey substation.[4] Resources associated with the other substations continued to be dispatched in three blocks between 11:00a and 7:00p.

Tables 3 and 4 show loads at the five substations that RMP expected it could shed during each month of 2009 and 2010 based on the historical demand of enrolled customers. This is known as the 'nominal' load. The estimates of nominal load in Tables 3 and 4 do not take into account customers that opted out of events.

In 2009, the nominal load varied across months but not hours, as all available program resources were dispatched during the 2:00p – 6:00p window. Nominal loads were highest during July when irrigation demand was greatest.

Table 3. Program Nominal Resources (MW) in 2009 for Five Substations

	June (all event hours)	July (all event hours)	August (all event hours)
Program Nominal Irrigation Load (MW) served by substations in estimation sample	178	196	188
Source: Table 14, Schedule 72 and 72A Idaho Irrigation Load Programs 2009 Credit Rider Initiative Final Report and personal communications with Bill Marek about percentage of program nominal load served by Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations. Loads are not adjusted for opt-outs. Nominal load is the load that RMP expected it could shed based on program enrollment and transmission and distribution constraints.			

[4] In addition, there was an AMD dispatch block on Amps 3 days/week from 6:00p -12:00a. This involved a small amount of load, approximately 1.75 MW per dispatch or 5.3MW in total. All AMD dispatches from all substations accounted for ~15 MW of participating load.

In 2010, the nominal loads on the five substations varied between months and event hour, as program resources were dispatched in several four-hour blocks, as described above. The nominal loads do not take into account the gradual ramping down and up of loads at the beginning and end of the period or opt outs.

Table 4. Program Nominal Resources (MW) in 2010 for Five Substations

	7-10a	11:00a	12:00p	1:00p	2:00p	3:00p	4:00p	5:00p	6:00p	7:00p	8p-12a
June	0.0	47.0	47.0	49.0	89.3	148.8	148.8	148.8	110.1	5.8	1.6
July 1-July 19	0.0	50.7	50.7	53.0	96.5	160.7	160.7	160.7	118.9	6.2	1.8
July 20-July 31	17.1	42.6	42.6	44.9	88.4	151.7	151.7	151.7	109.9	6.2	1.8
August	16.9	42.0	42.0	44.2	87.1	149.6	149.6	149.6	108.3	6.2	1.7

Source: Schedule 72 and 72A Idaho Irrigation Load Programs 2010 Credit Rider Initiative Final Report and personal communications with Bill Marek. Loads are not adjusted for opt outs. Nominal load is the load that RMP expected it could shed based on program enrollment and transmission and distribution constraints.

Data

RMP provided Cadmus with 60 second interval data for five substations (Amps, Big Grassey, Bonneville, Jefferson, Rigby) that served irrigators in its Idaho service territory in 2009 and 2010. The substations accounted for approximately 77 percent of RMP's irrigation load subscribed in the program in Idaho in 2010. RMP also provided Cadmus with data about the days and hours when direct load control resources were dispatched.

Cadmus performed a number of quality checks on and adjustments to the interval data before analyzing the load impacts. We first put the 60 second interval data on an hourly basis by calculating average hourly loads for each substation. The hourly load data were then plotted and examined for irregularities. While the minute interval data did exhibit some random spikes and drops in load (normal perturbations in electrical Grid operations), these abnormalities were not evident after the minute interval data were averaged over the hour.

Next, we obtained hourly and daily weather data for Rexburg and Idaho Falls weather stations from the National Weather Service and merged it with the hourly load data. The weather variables in the analysis include the daily evapotranspiration rate, temperature (hourly), and rainfall (hourly).[5]

[5] The evapotranspiration rate was a weighted average of crop-specific ETRs, with weights equal to the share of land planted in the crops.

Last, Cadmus mapped information on the occurrence of load control event hours to the data. We created separate indicator variables for each hour of each event, which were included in the model.

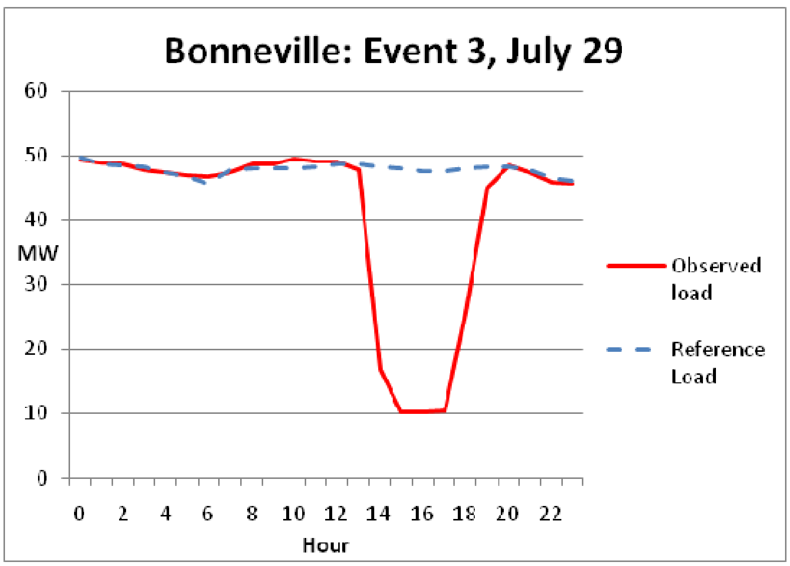
Impact Estimation Approach

The Cadmus approach to estimating the load reductions in each event was to estimate a reference load (what demand would have been in each hour of an event if the event had not occurred) in each hour during an event window. The difference between the actual load and the reference load in an event hour is the estimate of the program's impact during that event hour.

Figure 2 illustrates the approach. It shows the hourly loads for the Bonneville substation on July 23, 2009, when RMP called the third event of the summer. The event window was 2:00p to 6:00p. The red (solid) line is the observed load. The blue (dashed) line is the reference load that was generated with a regression model. The impact of the event in each hour is the difference between the metered load (red line) and the reference load (blue line). The figure depicts an estimated average hourly impact of approximately 38 MW.

The reference load can be estimated in several ways. One is a day matching approach. This involves estimating the (unconditional) average of the loads in the same hour in the two weekdays immediately preceding and following the event. If irrigation demand conditions, which are a function of weather, evapotranspiration, crop maturity, and other factors, on the reference days are similar to those on the event day, the reference load will likely represent well what demand would have been, and the difference between observed and reference loads will be an accurate estimate of the true load reduction. However, if any of the demand conditions change, the load reduction estimates will be biased.

Figure 2. Illustration of Event Impact Estimation Approach



The second approach is multivariate regression in which loads are modeled as a function of weather, time, and calendar variables. This method accounts for differences in demand conditions between event and non-event days and will generate a more accurate reference load.

Cadmus determined that because of trends in irrigation demand over the growing season that the day matching approach would not be appropriate. Reference loads were estimated using an hourly demand regression models.

Conditional Demand Impact Estimation

Using regression analysis, Cadmus also modeled hourly demand as a function of weather (evapo-transpiration, temperature, and rainfall), calendar and time effects (week of month, day of the week, and hour), and load in the same hour in the previous day.[6] The models also included separate indicator variables for each hour of each event and for each of the six hours following and preceding each event. The coefficients on the event hour variables represent the differences between the observed loads and the reference loads in the event hours. The Appendix describes the model specification in greater detail.

Cadmus estimated separate demand models for each of the substations and event months (June, July, and August). Thus, there were a total of 15 substation models (5 stations x 3 months). We estimated separate substation month models for two reasons. First, each substation has a somewhat different load shape over the summer, reflecting differences between stations in cropping practices and irrigation and non-irrigation demand.[7] Second, each substation's load shape varies significantly over the summer, reflecting changes in crop maturity, evapo-transpiration, soil-type temperature, wind, relative humidity, solar radiation, and rainfall over the growing season.

Model Estimation and Diagnostics

Cadmus estimated the models by Generalized Least Squares (GLS) under the assumption of auto-correlated errors, that is, load in each hour is assumed to be correlated with the load during a preceding hour. The error term was modeled as an autoregressive process with lag one.

We performed a number of tests to evaluate the predictive ability of the substation regression models. These tests included inspection of the signs and statistical significance of the models' coefficients, estimation of overall explanatory power of each model, represented by R^2 statistic,

[6] Loads were modeled as a function of the average temperature in the preceding 24 hours, total rainfall in the preceding 24 hours, and average daily evapo-transpiration over the preceding three days. The week of month variables capture changes in irrigation demand related to changes in cropping activities. The days of the week and hour of the day variables capture irrigation demand that varies by day and hour.

[7] The Rigby substation is different from the other stations in that it has significant non-irrigation loads.

and tests of the predictive ability of the models in hours when events could have been called on non-event days.[8] We used the results of the tests in selecting the final model specifications.

The models predict accurately what loads would have been in hours when events were not but could have been called. Table 6 reports the median absolute percentage error, the median of the percentage difference between the observed load and the load predicted by the model (|kW-model predicted kW)|/kW, during non-event hours on July weekdays between 2 and 6 pm.

Table 6. Median Absolute Percentage Error for July 2009

Hour	Amps	Big Grassey	Bonneville	Jefferson	Rigby
2:00 PM	0.74%	1.45%	1.35%	1.54%	0.72%
3:00 PM	0.86%	1.44%	1.28%	1.48%	0.67%
4:00 PM	1.62%	1.29%	0.87%	1.28%	0.64%
5:00 PM	0.95%	1.04%	1.09%	1.85%	0.67%
Note: Absolute percent error is =|predicted MW – actual MW|/ actual MW.					

For example, in 50 percent of the 3 pm non-event hours at the Bonneville station, the regression model predicts a load that is within 1.28 percent of the actual load. The median absolute prediction error ranges from less than 0.7 percent to just below two percent. Fifty percent (N=10) of the substation-hour median percentage errors are less 1.2 percent.

Estimated Load Reductions in 2009

Table 7 reports an estimate of the total load reduction for the Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations and all Idaho irrigation in each event hour during summer 2009.[9] The estimate for Idaho was obtained by dividing the substation estimate by the substation percentage of the Idaho irrigation load (77 percent). The Table also reports the realization rate for each event hour (2:00p-6:00p time window), which is the ratio of the estimated total load reduction in a given hour to the nominal load adjusted for irrigation loads that opted out of the event.[10] The realization rate is a function of the estimated load reduction (the numerator) and expectations about loads that can be shed (the denominator). It may be less than or equal to 100 percent depending on technical performance of the control equipment (i.e., signals and transmitted and received and pumps are shut off) and whether irrigation demand during the season was less than or greater than expected.

[8] In general, the coefficients of the models have the expected signs and are statistically significant. Loads were increasing in the evapo-transpiration rate and temperature and decreasing in rainfall. Loads were generally highest during the afternoon and early evening hours. Also, based on their R^2 statistics, the models explain a large percentage of the variation in irrigation loads.

[9] The Appendix contains estimates of the reduction in load at the substation level in each event hour.

[10] Cadmus adjusted the nominal load for an event by subtracting the amount of load that opted out the event.

Table 7. Estimated Load Reductions and Realization Rates in 2009

Date	Event	Hour	Estimated Load Reduction - Five substations (MW)	Estimated Load Reduction - All Idaho Irrigation (MW)	Hourly Opt-Out Adjusted Realization Rate
30-Jun	Event 1	Hour 1	-41.8	-54.3	24.8%
		Hour 2	-71.8	-93.2	42.6%
		Hour 3	-70.7	-91.8	42.0%
		Hour 4	-66.4	-86.3	39.5%
17-Jul	Event 2	Hour 1	-111.1	-144.3	60.8%
		Hour 2	-157.8	-204.9	86.3%
		Hour 3	-158.0	-205.2	86.4%
		Hour 4	-151.6	-196.9	82.9%
23-Jul	Event 3	Hour 1	-102.4	-133.0	55.7%
		Hour 2	-137.7	-178.9	74.9%
		Hour 3	-138.6	-180.0	75.3%
		Hour 4	-136.5	-177.2	74.2%
3-Aug	Event 4	Hour 1	-33.6	-43.6	18.5%
		Hour 2	-50.0	-65.0	27.6%
		Hour 3	-48.1	-62.5	26.5%
		Hour 4	-48.0	-62.4	26.5%
5-Aug	Event 5	Hour 1	-30.8	-40.0	17.0%
		Hour 2	-50.0	-65.0	27.6%
		Hour 3	-49.0	-63.7	27.1%
		Hour 4	-47.4	-61.6	26.2%
13-Aug	Event 6	Hour 1	-36.6	-47.6	19.9%
		Hour 2	-45.9	-59.6	24.9%
		Hour 3	-45.4	-58.9	24.6%
		Hour 4	-45.6	-59.2	24.7%

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

The Program reduced irrigation loads in each event hour. The estimated load reductions ranged from -158 MW to -31 MW and were different from zero at the 5 percent significance level.[11] The estimated reductions in Idaho irrigation loads ranged from 40 MW to 205 MW. The

[11] The Appendix contains estimated confidence intervals for the estimated load reductions in all event hours.

estimates also exhibit the expected patterns. First, during each event, the estimated load reduction in the first hour was the smallest, consistent with the staggering of the event initiation for grid reliability. (During hours two, three, and four, there is very little difference in the estimated load reductions.) Second, the load reductions over the summer reflected the seasonal pattern of irrigation demand. The load reductions were largest in July, when loads and irrigation demand were at their peak. The maximum load reductions on the five substations of 158 MW and in Idaho irrigation loads of 205 MW were achieved on July 17 (event 2) during event hour 3. The estimated load reductions were significantly smaller in June and August, when irrigation demand was much lower.

The realization rates, which show how much load was shed relative to expectation in any given hour, ranged from a low of 17 percent during hour 1 of event 5 to a high of 86 percent during hour 3 of Event 2. As expected, realization rates were significantly higher in July than in June or August because of irrigation practices and crop maturity. Nominal loads were not adjusted downward to reflect the lower irrigation demand in June and August. Hence, the low realization rates were due not to Program performance but rather to below average irrigation demand and the fact that nominal rates during June and August are lower. RMP may want to consider adjusting its estimates of nominal loads to reflect changes in irrigation demand.

Estimated Load Reductions in 2010

During events in 2010, program resources were dispatched in three or four blocks over 8 or 12 hours. Loads were dispatched outside of the 2:00p to 6:00p window because of potential adverse impacts on the transmission and distribution system. Table 8 reports an estimate of the maximum hourly load reduction in each block of each event during summer 2010.[12] Cadmus reports the maximum in each block of hours instead of in each hour because of the large number of event hours. The load reductions cover the Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations. It should be noted that loads that were shed between 7:00a and 10:00a or 11:00a and 1:00p resumed at the end of the event, leaving less opportunity for load reductions in subsequent hours (note: loads that were were controlled between 7:00a and 10:00a and 11:00a and 1:00p resumed at the end of the event, leaving less opportunity for load reductions in subsequent hours).

The load impacts were greatest during 2:00p – 6:00p, when most Schedule 72a resources were dispatched (see Table 4). The maximum hourly load reduction occurred on July 8, when irrigation loads on the five substations were reduced by approximately 120 MW and the Idaho irrigation load was reduced by 156 MW. Load impacts were smaller in June and August, when irrigation demand was lower.

[12] The Appendix contains estimates of the load reduction in each event hour.

Table 8. Estimated Load Reductions in 2010

Date	Event	Load	7 AM - 10 AM	11 AM - 1 PM	2 PM - 5 PM	6 PM
29-Jun	Event 1	5 Substations	N/A	-34.8	-87.0	-61.7
		All ID Irrigation	N/A	-45.2	-113.0	-80.1
8-Jul	Event 2	5 Substations	N/A	-49.6	-119.8	-85.7
		All ID Irrigation	N/A	-64.4	-155.5	-111.3
15-Jul	Event 3	5 Substations	N/A	-44.2	-107.0	-86.6
		All ID Irrigation	N/A	-57.4	-139.0	-112.5
16-Jul	Event 4	5 Substations	-39.9	0.0	-100.5	-77.7
		All ID Irrigation	-51.8	0.0	-130.5	-101.0
19-Jul	Event 5	5 Substations	-40.2	-17.9	-103.1	-83.3
		All ID Irrigation	-52.2	-23.2	-133.9	-108.2
20-Jul	Event 6	5 Substations	-48.3	-15.1	-105.4	-82.2
		All ID Irrigation	-62.7	-19.7	-136.9	-106.7
26-Jul	Event 7	5 Substations	-36.1	-12.2	-89.7	-75.8
		All ID Irrigation	-46.9	-15.9	-116.5	-98.4
2-Aug	Event 8	5 Substations	-2.4	-3.1	-6.7	1.3
		All ID Irrigation	-3.1	-4.0	-8.6	1.7
5-Aug	Event 9	5 Substations	-8.7	-10.0	-42.2	-31.5
		All ID Irrigation	-11.3	-12.9	-54.8	-41.0
24-Aug	Event 10	5 Substations	-25.5	-6.0	-41.3	-31.8
		All ID Irrigation	-33.2	-7.8	-53.6	-41.3
26-Aug	Event 11	5 Substations	-20.4	-2.6	-44.3	-30.6
		All ID Irrigation	-26.5	-3.4	-57.5	-39.7

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

The hourly MW impacts were smaller in 2010 than in 2009 because load control resources were dispatched over a larger number of hours. The dispatching of resources in the morning and early afternoon and early evening to address transmission and distribution issues meant that there was less potential to reduce loads during peak hours. To put the 2010 load impacts in perspective, Table 9 reports realization rates, the ratio of the estimated load impact to the nominal load in the hour adjusted for opt outs.[13] *The nominal loads during peak hours were smaller in 2010 than in 2009 because programs resources were dispatched before and after the 2:00p – 6:00p period. The realization rates account for the smaller amount of load that could have been shed between 2:00p and 6:00p.*

[13] The load opting out was subtracted from the nominal load for hours 2:00p – 6:00p for each event.

Table 9. Estimated Realization Rates in 2010 (Based on Nominal Capacity)

Date	Event	7 AM - 10 AM	11 AM - 1 PM	2 PM - 5 PM	6 PM
29-Jun	Event 1	N/A	71.0%	60.3%	56.0%
8-Jul	Event 2	N/A	93.7%	77.4%	72.1%
15-Jul	Event 3	N/A	83.5%	76.0%	72.9%
16-Jul	Event 4	N/A	0.0%	74.0%	70.8%
19-Jul	Event 5	234.9%	39.8%	76.7%	75.8%
20-Jul	Event 6	282.0%	33.7%	82.0%	74.8%
26-Jul	Event 7	211.3%	27.2%	63.9%	69.0%
2-Aug	Event 8	14.1%	6.9%	4.5%	-1.2%
5-Aug	Event 9	51.4%	22.5%	29.7%	29.1%
24-Aug	Event 10	151.4%	13.5%	28.6%	29.4%
26-Aug	Event 11	121.1%	6.0%	30.2%	28.2%
Notes: Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load. Opt out loads obtained from Schedule 72 & 72A Idaho Irrigation Load Control Programs: 2009 Credit Rider Initiative Final Report.					

During hours when events are traditionally called, the realization rates ranged between 29 percent on August 24 and 82 percent on July 20.[14] (We ignore the August 2 event, as load reductions were uniformly and abnormally low.[15]) During peak irrigation demand between the first and third weeks of July, the realization rate ranged between 77 and 82 percent of nominal load. These impacts are slightly lower than but still close to those in 2009. The difference in realization rates may reflect the fact that irrigation demand in 2010 was relatively low because of cooler weather throughout the summer.

Conclusions

Rocky Mountain Power asked Cadmus to evaluate the demand impacts of its Idaho irrigation load control program. In 2010, the Program enrolled 1,975 customers and had approximately 283 MW of participating load. However, this participating load was more than RMP could dispatch during peak hours because of transmission and distribution system constraints. This has had the effect of reducing the Program's cost-effectiveness.

[14] On some event days, the maximum hourly realization rate between 7:00a and 10:00a exceeded 100 percent. This indicates that in these hours either the Program achieved significantly greater demand reductions than expected, or the nominal loads are too low,

[15] Irrigation demand is typically very low at the beginning of August when hay is harvested and water to field crops is turned off to initiate the crop maturation process prior to harvest. Accordingly, potential demand reductions are very small. However, the nominal load covers all of August and does not reflect haying and crop maturation. The small, negative demand reduction in the 6:00 p hour is statistically indistinguishable from zero.

Cadmus estimated the hourly load reductions from the Program in 2009 and 2010 using regression analysis of SCADA data from five substations in Idaho. In addition, Cadmus examined the coincidence of the program impacts with the PacifiCorp system peak demands.

There are several noteworthy aspects of the methodology:

- The impact analysis was based on SCADA data at the substation level. Since the majority of the loads being served by these substations consist of irrigation, the amount of "noise" in the data resulting from the variability of non-irrigation loads is expected to be minimal.

- The estimation methodology did not consider Rocky Mountain Power's education of irrigators about efficient irrigation practices. If the benefits from education were taken into consideration the load shifting from education would have the effect of improving measured impact or realization rate.

- The hourly analysis of loads did not account for staggering in the dispatching of loads at the beginning and end of events for grid reliability purposes. As a result, the estimated load impacts in the first and last hours are an estimate of the average load reduction over the hour and may not represent the true reduction at the beginning (likely to be smaller than estimated) or end of the hour (likely to be larger).

- In the calculation of realization rates, the analysis adjusts for the required scheduling of 22 percent of the available participating loads outside of the 2:00p-6:00p time period. This scheduling restriction was implemented in 2010 to accommodate the Grid control voltage limitations previously noted. While this did not impact hourly realization rates, it did have a significant effect on the difference between the nominal loads and the aggregated reductions achieved.

Year	Nominal Load	Aggregated Reduction
2009	260 MW	205 MW
2010	283 MW	156 MW

The analysis of substation loads showed the following:

- In 2009, the maximum hourly load reduction on the five substations was 158 MW or 205 MW for all Idaho irrigation program loads. This represented 86 percent of the nominal program resources dispatched in that hour. The realization rates, which show how much load was shed relative to expectation, ranged from a low of 17 percent on August 5 to the July 17 high of 86 percent. In 2010, the maximum hourly load reduction was 120 MW or 156 MW for all Idaho irrigation program loads. This occurred on July 8 and represented 77 percent of the opt-out-adjusted nominal load dispatched in the hour. On

July 20, a load reduction of 120 MW resulted in the maximum realization rate of 82 percent.

- Realization rates were calculated based on expected loads, or in the case of the Rocky Mountain Program, loads that could safely be dispatched without adversely impacting line voltages. This is an important distinction worth noting. Had the calculation of realization rates been based on total participating loads, this would have resulted in lower realization rates. As program cost-effectiveness is calculated on actual load reductions relative to a program's costs (rather than a realization rate), realizations rates should not be considered the definitive measurement of a program's effectiveness and value.

- The load reductions and realization rates in any year may not be representative of typical load impacts the program might achieve because of annual variations in irrigation demand.

- PacifiCorp system peak coincides with hours when events are traditionally called (hours 2:00p-5:00p).

Recommendations

While the Program has achieved significant load reductions, the cost-effective has been adversely impacted by the level of participation on a megawatt basis. As noted above, in 2009 and 2010, the Program enrolled more load on some substations than it could dispatch during peak hours because of transmission and distribution constraints. RMP could reduce enrollments to a level consistent with the system's ability to dispatch loads. Or if technically feasible, RMP could increase the Program's cost-effectiveness by upgrading the transmission and distribution system to alleviate constraints on when load can be dispatched.

Appendix

Substation Hourly Load Model

Let j=1,2..., J index the events and h=1,2…, H index hours of each event. Also, let MW_{it} be the electricity load of substation i at time (hour) t. Then (suppressing the index *i*) substation i's MW demand at time t (corresponding to a week of the month, day, and hour) can be written as:

$$MW_t = \alpha_0 + \alpha_1\ EvapTR72hour_t + \alpha_2\ temp24hour_t + \alpha_3 rainfall24hour_t + \sum_{w=1}^{3} \pi_w\ weekofmonth_{wt} + \sum_{d=1}^{6} \delta_d\ dayofweek_{dt} + \sum_{k=1}^{23} \gamma_k\ hourofday_{kt} + \theta MW_{t-24} + \sum_{j=1}^{J} \sum_{h=1}^{H} \rho_{jh} eventhour_{jht} + \sum_{j=1}^{J} \sum_{h=1}^{6} \varphi_{jh} preeventhour_{jht} + \sum_{j=1}^{J} \sum_{h=1}^{6} \omega_{jh} posteventhour_{jht} + \varepsilon_t$$

The right hand side variables in the model are defined as follows:

- $EvapTR72hour_t$ is the average evapo-transpiration rate over the previous 72 $hours_t$ at time t.
- $Temp24hour_t$ is the average temperature over the previous 24 hours at time t.
- $Rainfall24hour_t$ is the total rainfall over the previous 24 hours.
- $Weekofmonth_{wt}$ equals one if time t is in week w, w=1 to 3, and equals zero, otherwise. Day_{dt}, d=1 to 6, and $hourof\ day_{kt}$, k=1 to 23, are defined similarly.
- $Eventhour_{jht}$ equals one if time t is in hour h, h=1 to H, of event j, j=1 to J, and equals zero, otherwise. $Preeventhour_{jht}$ and $Posteventhour_{jht}$ are defined similarly.
- ε_t is the error term of the model representing random influences on the demand of customer i at time t.

The parameters to be estimated and their interpretations are as follows:

- ρ_{hj} is the impact of hour h of event j on demand. It is the difference between the estimate of what demand would have been if an event had not been called (reference load) and the actual demand in the hour.
- ω_{hj} is the impact of hour h after event j on demand. The coefficients capture any shifting of irrigation loads in response to the load control events.
- ϕ_{hj} is the impact of hour h before event j on demand. The coefficients capture any shifting of irrigation loads because of the load control events.
- α_0 is substation load at the omitted hour (Sundays at the 12 am hour in the first month).

- α_1 is the impact of average evapo-transpiration rate in the previous 72 hours on demand. α_2 shows the impact of temperature in the previous 24 hours on demand. α_3 measures the impact of rainfall in the previous 24 hours on demand.
- π_w, w=1 to 3, is the impact of week of month *w* on demand.
- δ_d, d=1 to 6, is the impact of day of the week *d* on demand.
- γ_k, k=1 to 23, is the impact of hour *k* on demand.

Appendix Table A.1. 2010 Estimated Hourly Load Reductions with 95 Percent Confidence Intervals

Date	Event	Hour	Estimated Load Reduction - Five substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-Out Adjusted Nominal Load	Opt-Out Adjusted Realization Rate
30-Jun	Event 1	Hour 1	-41.8	-55	-28	-54.3	168.4	24.8%
		Hour 2	-71.8	-86	-57	-93.2	168.4	42.6%
		Hour 3	-70.7	-86	-56	-91.8	168.4	42.0%
		Hour 4	-66.4	-82	-50	-86.3	168.4	39.5%
17-Jul	Event 2	Hour 1	-111.1	-125	-97	-144.3	182.8	60.8%
		Hour 2	-157.8	-172	-144	-204.9	182.8	86.3%
		Hour 3	-158.0	-172	-144	-205.2	182.8	86.4%
		Hour 4	-151.6	-166	-138	-196.9	182.8	82.9%
23-Jul	Event 3	Hour 1	-102.4	-116	-89	-133.0	184.0	55.7%
		Hour 2	-137.7	-152	-124	-178.9	184.0	74.9%
		Hour 3	-138.6	-153	-124	-180.0	184.0	75.3%
		Hour 4	-136.5	-150	-122	-177.2	184.0	74.2%
3-Aug	Event 4	Hour 1	-33.6	-42	-25	-43.6	181.5	18.5%
		Hour 2	-50.0	-58	-42	-65.0	181.5	27.6%
		Hour 3	-48.1	-57	-40	-62.5	181.5	26.5%
		Hour 4	-48.0	-56	-40	-62.4	181.5	26.5%
5-Aug	Event 5	Hour 1	-30.8	-39	-22	-40.0	181.0	17.0%
		Hour 2	-50.0	-59	-41	-65.0	181.0	27.6%
		Hour 3	-49.0	-58	-40	-63.7	181.0	27.1%
		Hour 4	-47.4	-56	-39	-61.6	181.0	26.2%
13-Aug	Event 6	Hour 1	-36.6	-45	-28	-47.6	184.2	19.9%
		Hour 2	-45.9	-54	-37	-59.6	184.2	24.9%
		Hour 3	-45.4	-54	-37	-58.9	184.2	24.6%
		Hour 4	-45.6	-54	-37	-59.2	184.2	24.7%

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

Appendix Table A.2. 2010 Estimated Hourly Load Reductions with 95 Percent Confidence Intervals

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
29-Jun	Event 1	11:00 AM	11 AM - 1 PM	-32.7	-42.2	-23.1	-42.4	47.0	-69.6%	47.0
29-Jun	Event 1	12:00 PM	11 AM - 1 PM	-34.8	-44.0	-25.6	-45.2	47.0	-74.1%	47.0
29-Jun	Event 1	1:00 PM	11 AM - 1 PM	-28.3	-37.1	-19.5	-36.8	49.0	-57.8%	49.0
29-Jun	Event 1	2:00 PM	2 PM - 5 PM	-49.2	-58.9	-39.4	-63.8	84.8	-58.0%	89.3
29-Jun	Event 1	3:00 PM	2 PM - 5 PM	-87.0	-96.8	-77.2	-113.0	144.3	-60.3%	148.8
29-Jun	Event 1	4:00 PM	2 PM - 5 PM	-82.7	-92.5	-73.0	-107.5	144.3	-57.4%	148.8
29-Jun	Event 1	5:00 PM	2 PM - 5 PM	-75.8	-85.3	-66.3	-98.5	144.3	-52.6%	148.8
29-Jun	Event 1	6:00 PM	6 PM	-61.7	-70.9	-52.5	-80.1	110.1	-56.0%	110.1
8-Jul	Event 2	11:00 AM	11 AM - 1 PM	-48.7	-67.5	-29.9	-63.2	50.7	-96.0%	50.7
8-Jul	Event 2	12:00 PM	11 AM - 1 PM	-49.6	-67.9	-31.3	-64.4	50.7	-97.8%	50.7
8-Jul	Event 2	1:00 PM	11 AM - 1 PM	-39.0	-56.6	-21.4	-50.6	53.0	-73.6%	53.0
8-Jul	Event 2	2:00 PM	2 PM - 5 PM	-71.2	-90.3	-52.1	-92.4	90.5	-78.6%	96.5
8-Jul	Event 2	3:00 PM	2 PM - 5 PM	-119.8	-138.9	-100.6	-155.5	154.8	-77.4%	160.7
8-Jul	Event 2	4:00 PM	2 PM - 5 PM	-114.5	-133.5	-95.5	-148.7	154.8	-74.0%	160.7
8-Jul	Event 2	5:00 PM	2 PM - 5 PM	-104.9	-123.5	-86.2	-136.2	154.8	-67.8%	160.7
8-Jul	Event 2	6:00 PM	6 PM	-85.7	-103.7	-67.6	-111.3	118.9	-72.1%	118.9
15-Jul	Event 3	11:00 AM	11 AM - 1 PM	-41.3	-60.1	-22.5	-53.6	50.7	-81.4%	50.7
15-Jul	Event 3	12:00 PM	11 AM - 1 PM	-44.2	-62.6	-25.9	-57.4	50.7	-87.2%	50.7
15-Jul	Event 3	1:00 PM	11 AM - 1 PM	-43.1	-61.0	-25.2	-56.0	53.0	-81.3%	53.0
15-Jul	Event 3	2:00 PM	2 PM - 5 PM	-65.6	-84.7	-46.5	-85.2	76.6	-85.6%	96.5
15-Jul	Event 3	3:00 PM	2 PM - 5 PM	-107.0	-126.2	-87.8	-139.0	140.9	-76.0%	160.7
15-Jul	Event 3	4:00 PM	2 PM - 5 PM	-104.4	-123.5	-85.4	-135.6	140.9	-74.1%	160.7
15-Jul	Event 3	5:00 PM	2 PM - 5 PM	-100.1	-118.8	-81.4	-130.0	140.9	-71.0%	160.7
15-Jul	Event 3	6:00 PM	6 PM	-86.6	-104.7	-68.6	-112.5	118.9	-72.9%	118.9
16-Jul	Event 4	7:00 AM	7 AM- 10 AM	-37.5	-56.4	-18.6	-48.7	17.1	-219.1%	17.1
16-Jul	Event 4	8:00 AM	7 AM- 10 AM	-39.9	-58.3	-21.5	-51.8	17.1	-233.2%	17.1
16-Jul	Event 4	9:00 AM	7 AM- 10 AM	-35.2	-52.8	-17.5	-45.7	17.1	-205.5%	17.1
16-Jul	Event 4	10:00 AM	7 AM- 10 AM	-0.2	-8.8	8.3	-0.3	17.1	-1.4%	17.1
16-Jul	Event 4	11:00 AM	11 AM - 1 PM	0.0	-8.4	8.4	0.0	42.6	0.0%	42.6
16-Jul	Event 4	12:00 PM	11 AM - 1 PM	0.1	-8.0	8.2	0.2	42.6	0.3%	42.6
16-Jul	Event 4	1:00 PM	11 AM - 1 PM	0.4	-7.4	8.2	0.5	44.9	0.9%	44.9
16-Jul	Event 4	2:00 PM	2 PM - 5 PM	-60.6	-79.8	-41.5	-78.7	72.6	-83.5%	88.4
16-Jul	Event 4	3:00 PM	2 PM - 5 PM	-100.5	-119.8	-81.2	-130.5	135.9	-74.0%	151.7
16-Jul	Event 4	4:00 PM	2 PM - 5 PM	-98.6	-117.7	-79.4	-128.0	135.9	-72.5%	151.7
16-Jul	Event 4	5:00 PM	2 PM - 5 PM	-93.4	-112.2	-74.6	-121.3	135.9	-68.7%	151.7
16-Jul	Event 4	6:00 PM	6 PM	-77.7	-95.9	-59.6	-101.0	109.9	-70.8%	109.9
19-Jul	Event 5	7:00 AM	7 AM- 10 AM	-37.4	-56.2	-18.5	-48.5	17.1	-218.5%	17.1
19-Jul	Event 5	8:00 AM	7 AM- 10 AM	-40.2	-58.5	-21.8	-52.2	17.1	-234.9%	17.1
19-Jul	Event 5	9:00 AM	7 AM- 10 AM	-39.8	-57.5	-22.2	-51.7	17.1	-232.8%	17.1
19-Jul	Event 5	10:00 AM	7 AM- 10 AM	-18.1	-26.7	-9.5	-23.5	17.1	-105.8%	17.1
19-Jul	Event 5	11:00 AM	11 AM - 1 PM	-17.9	-26.3	-9.4	-23.2	42.6	-41.9%	42.6
19-Jul	Event 5	12:00 PM	11 AM - 1 PM	-16.7	-24.9	-8.6	-21.7	42.6	-39.3%	42.6
19-Jul	Event 5	1:00 PM	11 AM - 1 PM	-14.6	-22.4	-6.7	-18.9	44.9	-32.4%	44.9
19-Jul	Event 5	2:00 PM	2 PM - 5 PM	-61.3	-80.4	-42.2	-79.6	71.1	-86.2%	88.4
19-Jul	Event 5	3:00 PM	2 PM - 5 PM	-103.1	-122.3	-83.9	-133.9	134.5	-76.7%	151.7
19-Jul	Event 5	4:00 PM	2 PM - 5 PM	-101.2	-120.3	-82.2	-131.5	134.5	-75.3%	151.7
19-Jul	Event 5	5:00 PM	2 PM - 5 PM	-98.6	-117.3	-80.0	-128.1	134.5	-73.4%	151.7
19-Jul	Event 5	6:00 PM	6 PM	-83.3	-101.4	-65.3	-108.2	109.9	-75.8%	109.9

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
20-Jul	Event 6	7:00 AM	7 AM- 10 AM	-46.4	-65.3	-27.5	-60.2	17.1	-271.1%	17.1
20-Jul	Event 6	8:00 AM	7 AM- 10 AM	-48.3	-66.6	-29.9	-62.7	17.1	-282.0%	17.1
20-Jul	Event 6	9:00 AM	7 AM- 10 AM	-44.4	-62.1	-26.8	-57.7	17.1	-259.7%	17.1
20-Jul	Event 6	10:00 AM	7 AM- 10 AM	-12.7	-21.4	-4.1	-16.5	17.1	-74.5%	17.1
20-Jul	Event 6	11:00 AM	11 AM - 1 PM	-13.6	-22.1	-5.2	-17.7	42.6	-32.0%	42.6
20-Jul	Event 6	12:00 PM	11 AM - 1 PM	-14.8	-23.0	-6.6	-19.2	42.6	-34.6%	42.6
20-Jul	Event 6	1:00 PM	11 AM - 1 PM	-15.1	-23.0	-7.3	-19.7	44.9	-33.7%	44.9
20-Jul	Event 6	2:00 PM	2 PM - 5 PM	-71.5	-90.7	-52.3	-92.9	65.2	-109.6%	88.4
20-Jul	Event 6	3:00 PM	2 PM - 5 PM	-105.4	-124.8	-86.1	-136.9	128.6	-82.0%	151.7
20-Jul	Event 6	4:00 PM	2 PM - 5 PM	-102.0	-121.2	-82.8	-132.5	128.6	-79.3%	151.7
20-Jul	Event 6	5:00 PM	2 PM - 5 PM	-98.0	-116.9	-79.1	-127.3	128.6	-76.2%	151.7
20-Jul	Event 6	6:00 PM	6 PM	-82.2	-100.5	-63.9	-106.7	109.9	-74.8%	109.9
26-Jul	Event 7	7:00 AM	7 AM- 10 AM	-32.9	-51.7	-14.0	-42.7	17.1	-192.1%	17.1
26-Jul	Event 7	8:00 AM	7 AM- 10 AM	-36.1	-54.5	-17.8	-46.9	17.1	-211.3%	17.1
26-Jul	Event 7	9:00 AM	7 AM- 10 AM	-35.0	-52.6	-17.3	-45.4	17.1	-204.3%	17.1
26-Jul	Event 7	10:00 AM	7 AM- 10 AM	-10.4	-18.9	-1.8	-13.5	17.1	-60.7%	17.1
26-Jul	Event 7	11:00 AM	11 AM - 1 PM	-11.0	-19.3	-2.6	-14.2	42.6	-25.7%	42.6
26-Jul	Event 7	12:00 PM	11 AM - 1 PM	-11.1	-19.3	-3.0	-14.4	42.6	-26.1%	42.6
26-Jul	Event 7	1:00 PM	11 AM - 1 PM	-12.2	-20.0	-4.4	-15.9	44.9	-27.2%	44.9
26-Jul	Event 7	2:00 PM	2 PM - 5 PM	-54.7	-73.8	-35.6	-71.0	76.9	-71.1%	88.4
26-Jul	Event 7	3:00 PM	2 PM - 5 PM	-89.7	-108.9	-70.5	-116.5	140.3	-63.9%	151.7
26-Jul	Event 7	4:00 PM	2 PM - 5 PM	-88.8	-107.9	-69.7	-115.3	140.3	-63.3%	151.7
26-Jul	Event 7	5:00 PM	2 PM - 5 PM	-85.3	-104.1	-66.5	-110.8	140.3	-60.8%	151.7
26-Jul	Event 7	6:00 PM	6 PM	-75.8	-94.1	-57.5	-98.4	109.9	-69.0%	109.9
26-Jul	Event 8	7:00 AM	7 AM- 10 AM	24.1	14.1	34.0	31.3	17.1	140.8%	17.1
2-Aug	Event 8	8:00 AM	7 AM- 10 AM	25.3	15.6	34.9	32.8	17.1	147.7%	17.1
2-Aug	Event 8	9:00 AM	7 AM- 10 AM	29.7	20.4	38.9	38.6	17.1	173.5%	17.1
2-Aug	Event 8	10:00 AM	7 AM- 10 AM	-2.4	-6.6	1.7	-3.1	17.1	-14.1%	17.1
2-Aug	Event 8	11:00 AM	11 AM - 1 PM	-2.0	-6.1	2.0	-2.6	42.6	-4.8%	42.6
2-Aug	Event 8	12:00 PM	11 AM - 1 PM	-2.1	-6.0	1.8	-2.7	42.6	-4.9%	42.6
2-Aug	Event 8	1:00 PM	11 AM - 1 PM	-3.1	-6.8	0.6	-4.0	44.9	-6.9%	44.9
2-Aug	Event 8	2:00 PM	2 PM - 5 PM	11.6	1.5	21.7	15.1	83.6	13.9%	88.4
2-Aug	Event 8	3:00 PM	2 PM - 5 PM	3.8	-6.3	14.0	5.0	146.9	2.6%	151.7
2-Aug	Event 8	4:00 PM	2 PM - 5 PM	-3.0	-13.1	7.0	-3.9	146.9	-2.1%	151.7
2-Aug	Event 8	5:00 PM	2 PM - 5 PM	-6.7	-16.5	3.2	-8.6	146.9	-4.5%	151.7
2-Aug	Event 8	6:00 PM	6 PM	1.3	-8.2	10.9	1.7	109.9	1.2%	109.9
5-Aug	Event 9	7:00 AM	7 AM- 10 AM	-8.0	-18.0	2.0	-10.4	16.9	-47.3%	16.9
5-Aug	Event 9	8:00 AM	7 AM- 10 AM	-8.7	-18.4	1.0	-11.3	16.9	-51.4%	16.9
5-Aug	Event 9	9:00 AM	7 AM- 10 AM	-6.9	-16.2	2.4	-9.0	16.9	-41.0%	16.9
5-Aug	Event 9	10:00 AM	7 AM- 10 AM	-8.2	-12.4	-3.9	-10.6	16.9	-48.5%	16.9
5-Aug	Event 9	11:00 AM	11 AM - 1 PM	-8.3	-12.5	-4.2	-10.8	42.0	-19.9%	42.0
5-Aug	Event 9	12:00 PM	11 AM - 1 PM	-8.6	-12.6	-4.7	-11.2	42.0	-20.5%	42.0
5-Aug	Event 9	1:00 PM	11 AM - 1 PM	-10.0	-13.7	-6.2	-12.9	44.2	-22.5%	44.2
5-Aug	Event 9	2:00 PM	2 PM - 5 PM	-19.3	-29.5	-9.2	-25.1	79.6	-24.3%	87.1
5-Aug	Event 9	3:00 PM	2 PM - 5 PM	-41.7	-51.9	-31.5	-54.2	142.0	-29.4%	149.6
5-Aug	Event 9	4:00 PM	2 PM - 5 PM	-42.2	-52.4	-32.0	-54.8	142.0	-29.7%	149.6
5-Aug	Event 9	5:00 PM	2 PM - 5 PM	-39.1	-49.1	-29.1	-50.8	142.0	-27.5%	149.6
5-Aug	Event 9	6:00 PM	6 PM	-31.5	-41.2	-21.9	-41.0	108.3	-29.1%	108.3
24-Aug	Event 10	7:00 AM	7 AM- 10 AM	-25.5	-35.5	-15.6	-33.2	16.9	-151.4%	16.9
24-Aug	Event 10	8:00 AM	7 AM- 10 AM	-24.9	-34.6	-15.2	-32.3	16.9	-147.6%	16.9
24-Aug	Event 10	9:00 AM	7 AM- 10 AM	-22.1	-31.4	-12.9	-28.8	16.9	-131.3%	16.9

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
24-Aug	Event 10	10:00 AM	7 AM- 10 AM	-5.0	-9.3	-0.7	-6.5	16.9	-29.6%	16.9
24-Aug	Event 10	11:00 AM	11 AM - 1 PM	-5.2	-9.3	-1.0	-6.7	42.0	-12.3%	42.0
24-Aug	Event 10	12:00 PM	11 AM - 1 PM	-5.5	-9.5	-1.5	-7.1	42.0	-13.1%	42.0
24-Aug	Event 10	1:00 PM	11 AM - 1 PM	-6.0	-9.8	-2.2	-7.8	44.2	-13.5%	44.2
24-Aug	Event 10	2:00 PM	2 PM - 5 PM	-32.0	-42.1	-21.9	-41.6	81.9	-39.1%	87.1
24-Aug	Event 10	3:00 PM	2 PM - 5 PM	-40.8	-50.9	-30.6	-52.9	144.3	-28.2%	149.6
24-Aug	Event 10	4:00 PM	2 PM - 5 PM	-39.0	-49.0	-28.9	-50.6	144.3	-27.0%	149.6
24-Aug	Event 10	5:00 PM	2 PM - 5 PM	-41.3	-51.1	-31.4	-53.6	144.3	-28.6%	149.6
24-Aug	Event 10	6:00 PM	6 PM	-31.8	-41.3	-22.3	-41.3	108.3	-29.4%	108.3
26-Aug	Event 11	7:00 AM	7 AM- 10 AM	-20.4	-30.4	-10.5	-26.5	16.9	-121.1%	16.9
26-Aug	Event 11	8:00 AM	7 AM- 10 AM	-19.0	-28.7	-9.3	-24.7	16.9	-112.7%	16.9
26-Aug	Event 11	9:00 AM	7 AM- 10 AM	-18.4	-27.6	-9.1	-23.8	16.9	-108.8%	16.9
26-Aug	Event 11	10:00 AM	7 AM- 10 AM	-2.5	-6.7	1.7	-3.2	16.9	-14.8%	16.9
26-Aug	Event 11	11:00 AM	11 AM - 1 PM	-2.0	-6.0	2.1	-2.6	42.0	-4.7%	42.0
26-Aug	Event 11	12:00 PM	11 AM - 1 PM	-2.6	-6.5	1.2	-3.4	42.0	-6.3%	42.0
26-Aug	Event 11	1:00 PM	11 AM - 1 PM	-2.5	-6.2	1.2	-3.3	44.2	-5.7%	44.2
26-Aug	Event 11	2:00 PM	2 PM - 5 PM	-31.9	-42.0	-21.8	-41.5	84.0	-38.0%	87.1
26-Aug	Event 11	3:00 PM	2 PM - 5 PM	-44.3	-54.4	-34.1	-57.5	146.4	-30.2%	149.6
26-Aug	Event 11	4:00 PM	2 PM - 5 PM	-40.5	-50.6	-30.4	-52.6	146.4	-27.7%	149.6
26-Aug	Event 11	5:00 PM	2 PM - 5 PM	-37.1	-47.0	-27.1	-48.1	146.4	-25.3%	149.6
26-Aug	Event 11	6:00 PM	6 PM	-30.6	-40.2	-20.9	-39.7	108.3	-28.2%	108.3