Lisa D. Nordstrom
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October 1, 2013

Attention: Filing Center
Public Utility Commission of Oregon
3930 Fairview Industrial Dr SE
P.O. Box 1088
Salem, OR 97308-1088

RE: UM ____ - Idaho Power Company's 2013 Smart Grid Report

Dear Sir or Madam:

Idaho Power Company herewith submits for filing its 2013 Smart Grid Report in compliance with Order No. 12-158 in Docket No. UM 1460. In addition to the Smart Grid Report, the Company has included the following documents:

Appendix A – Newspaper ad and email solicitation
Appendix B – Table of Smart Grid Initiatives
Appendix C – Acronym List
Appendix D1-D14 – Smart Grid Project Reports

Appendix D2, D3, and D4 are confidential and are being provided under separate cover under OAR 860-001-0070. A motion for protective order is attached.

Please address all data requests and other communication to:
Electronic: dockets@idahopower.com
Regular Mail: Lisa Nordstrom
Idaho Power Company
1221 W. Idaho Street
Boise, Idaho 83702

Informal questions concerning this filing may be directed to me or Sr. Regulatory Affairs Analyst, Darlene Nemnich, at 208-388-2505 or dnemnich@idahopower.com.

Sincerely,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt
Enclosures
cc: Service List – UM 1460
Service List – LC 58
Service List – UE 233
RA Files
Legal Files

CERTIFICATE OF SERVICE

UM ______

I hereby certify that on October 1, 2013, I served a true and correct copy of Idaho Power Company's 2013 Smart Grid Report on the parties in Dockets UM 1460, LC 58, and UE 233 by e-mail to said person(s) as indicated below.

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DATED: October 1, 2013

Kimberly Towell

Kimberly Towell, Executive Assistant

Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM _______

IN THE MATTER OF IDAHO POWER COMPANY'S 2013 ANNUAL SMART GRID REPORT	MOTION FOR PROTECTIVE ORDER

Pursuant to ORCP 36(C)(7) and OAR 860-001-0080, Idaho Power Company ("Idaho Power" or "Company") moves for the entry of the Public Utility Commission of Oregon's ("Commission") general protective order in this proceeding. Good cause exists to issue a Protective Order to protect commercially sensitive and confidential business information, as well as Critical Energy Infrastructure Information ("CEII") as defined by the Federal Energy Regulatory Commission, related to the Company's 2013 Annual Smart Grid Report.

In support of this Motion, the Company states:

1. The Commission's rules authorize Idaho Power to seek reasonable restrictions on discovery of trade secrets and other confidential business information. *See* 860-001-0080; ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also In re Investigation into the Cost of Providing Telecommunication Service*, Docket UM 351, Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").

2. On October 1, 2013, Idaho Power filed its 2013 Annual Smart Grid Report. Idaho Power anticipates that discovery in this proceeding will include requests for proprietary business and financial information, as well as protected CEII information. Idaho Power will be exposed to competitive, operational, and/or regulatory injury if it is forced to make unrestricted

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disclosure of its confidential business information. "The Commission's standard blanket protective order is designed to facilitate discovery in cases involving discovery of large numbers of documents." *See In re Portland Extended Area Service Region*, Docket UM 261, Order No. 91-958 (1991). Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

For the foregoing reasons, Idaho Power requests entry of a standard Protective Order in this docket.

DATED: October 1, 2013

Lisa D. Nordstrom

Lisa D. Nordstrom
Lead Counsel for Idaho Power Company

Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

Smart Grid Report for the Public Utility Commission of Oregon

October 1, 2013

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EXECUTIVE SUMMARY

Idaho Power Company (Idaho Power or the company) prepared this report in compliance with Order No. 12-158 issued by the Public Utility Commission of Oregon (OPUC) in docket UM 1460. The OPUC's smart grid goal and objectives set out in this order are as follows:

> *The Commission's goal is to benefit ratepayers of Oregon investor-owned utilities by fostering utility investments in real-time sensing, communication, control, and other smart-grid measures that are cost-effective to consumers and that achieve some of the following:*
>
> - *Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network*
> - *Enhance the ability to save energy and reduce peak demand*
> - *Enhance customer service and lower cost of utility operations*
> - *Enhance the ability to develop renewable resources and distributed generation.*

This document presents Idaho Power's first annual *Smart Grid Report* as directed in Order No. 12-158 and addresses Idaho Power's initial efforts toward accomplishing the OPUC's goals. This report explains the company's overall strategies, goals, and objectives as they pertain to its smart grid efforts. It provides a review of current smart grid projects, initiatives, and activities being performed by the company and describes additional projects the company plans to undertake in the next five years. Opportunities the company has identified, as well as potential constraints, are also discussed.

In June 2009, Idaho Power developed a smart grid vision. This smart grid vision led the company through the successful application, receipt, and deployment of a $47 million *American Reinvestment and Recovery Act of 2009* (ARRA) Smart Grid Investment Grant (SGIG) administered through the Department of Energy (DOE). Idaho Power received the ARRA SGIG from 2011 to mid-2013. Ten projects were funded with this grant and another two projects were deferred for future consideration. Most of the projects funded with this grant have been completed within the past year. Idaho Power plans to evaluate the ARRA SGIG project outcomes and update its smart grid approach in 2014.

New smart grid technologies and opportunities are evaluated by the company in a systematic process to determine if they solve an existing problem, improve efficiency, increase reliability, safety or security, or enhance customer satisfaction. Opportunities for funding smart grid projects are evaluated using common criteria alongside other capital projects being considered by the company.

Solicitation of Stakeholder Input

In preparation for filing this report, Idaho Power provided the public and other parties with opportunities to contribute information and asked for ideas on smart grid investments and applications. To solicit input from the general public, an advertisement—Share Your Ideas About Smart Grid—was placed in the two newspapers with the best coverage in Idaho Power's Oregon service area. An advertisement was placed in the *Argus Observer* (Ontario) on August 21 and 25, 2013, and in the *Hells Canyon Journal* (Halfway) on August 21 and 28, 2013. On August 21, 2013, Idaho Power sent an email soliciting comments to all parties on the service lists for docket, UM 1460; Idaho Power's last General Rate Case docket, UE 233; and Idaho Power's 2013 Integrated Resource Plan docket, LC 58. Idaho Power requested comments be submitted by September 18, giving parties four weeks to provide responses. Idaho Power received one inquiry (with no comment) from a customer as a result of the newspaper advertisement. No comments were received from the email solicitation. Copies of the newspaper advertisement and email solicitation are provided in Appendix A.

I. Smart Grid Strategy, Goals, and Objectives

The smart grid is a concept that utilities, vendors, politicians, and customers research, develop, and deploy new technologies to reduce costs and improve the operation of the electrical power system. The smart grid represents an opportunity to enhance the value customers receive from the electrical power system. Idaho Power is committed to helping customers realize this value through good planning and making wise investments. Both time and money will be needed to fully realize the benefits of the smart grid.

At Idaho Power, the smart grid vision (Figure 1) consists of seven major characteristics:

1. Enhance customer participation and satisfaction
2. Accommodate generation/storage
3. Enable new products/services/markets
4. Improve power quality
5. Optimize asset efficiency
6. Anticipate and respond to disturbances
7. Provide resilient operation/robustness

The company's strategy for realizing the smart grid vision consists of focusing investments in the following areas:

- Operations
    - Replace the outage management system
    - Develop a renewable energy integration tool (wind)
    - Install a transmission line situational awareness tool
    - Pilot a self-healing distribution network
- Customer Systems
    - Replace the customer information system (CIS)
    - Implement a web-based energy-use advising tool
    - Establish an enterprise data warehouse (EDW)

- Advanced Metering Infrastructure (AMI)
  - Upgrade the meter data management system
  - Install smart meters
  - Upgrade station communications
  - Pilot irrigation load control

Integrating these projects enhances Idaho Power's ability to manage peak demand, integrate renewable resources, maintain low electricity rates, offer time-variant pricing (TVP), increase energy efficiency, and improve grid reliability. These outcomes align with the OPUC's goal of fostering utility investments in real-time sensing, communication and control, and other smart grid measures that are cost-effective to benefit ratepayers of Oregon investor-owned utilities.

Figure 1
Idaho Power's smart grid vision

Idaho Power has a systematic process for evaluating smart grid projects. The Research, Development, and Deployment (RD&D) department is the primary department responsible for the assessment of new grid technologies, including smart grid opportunities. Project leaders are responsible for tracking and evaluating industry technologies, managing technology pilots, and assessing pilot-project outcomes.

The project leaders plan the utility-wide deployment of successful technologies and submit these plans for capital funding. Smart grid technologies are collected and evaluated with all other ideas. The high-level process is shown in Figure 2.

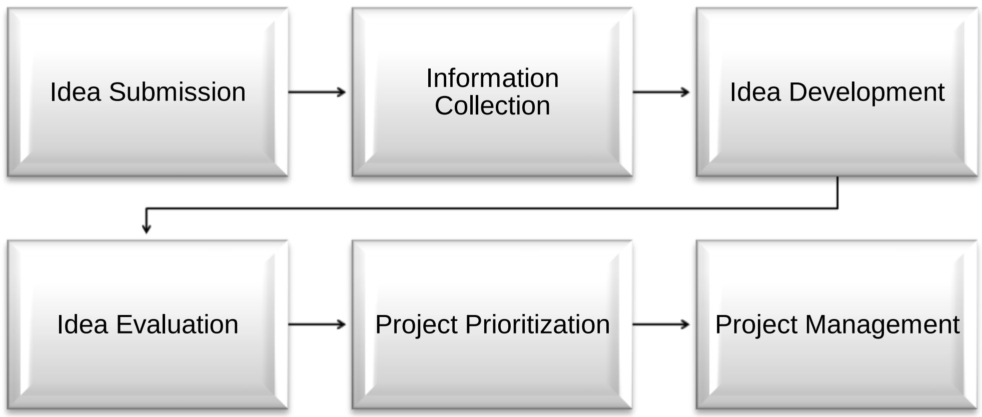

Figure 2
Idea processing

Smart grid ideas are analyzed to determine if they solve an existing problem, improve efficiency, increase reliability, safety or security, or enhance customer satisfaction. The RD&D leaders also develop smart grid ideas into a deployable pilot project and evaluate the cost benefit of the project. The pilot project is submitted to a review team to ensure all aspects of the project have been included in the initial design and to evaluate external impacts of the project (e.g., communication infrastructure and operating capabilities). The project is then evaluated for funding against all other projects. After the pilot project is funded and deployed, it is evaluated against the projected costs and benefits determined in the initial evaluation stage. If the pilot project meets expectations, a project plan is developed for utility-wide deployment and submitted for funding.

II. Status of Smart Grid Investments

The following sections describe the smart grid projects, initiatives, and activities currently underway and the results to date.

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Project

Idaho Power is improving the awareness of the transmission system through visualization of precise voltage at key transmission substation. (Awarness is the ability of the transmission system operators to detect potentially adverse operating conditions.) These precise voltage measurements are captured by time synchronized devices known as Phasor Measurement Units (PMUs). PMUs have been installed at sixteen transmission substation and generation stations in coordination with the Western Electricity Coordinating Council (WECC) Western Interconnection Synchrophasor Project (WISP). These PMUs are streaming the voltage data measurements, taken 30 times a second, to a data concentrator which archives the concentrated data for internal use and streams it on to the WECC Reliability Centers. By participating in the WECC WISP, Idaho Power will help improve the reliability of the western transmission system and gain access to software that provides visualization of the entire western transmission system.

A low frequency oscillation has been identified from the initial data analysis. This oscillation was detected using Oscillation Monitoring System (OMS) software, described later in this document, and has given rise to a future smart grid project to install additional PMUs to isolate the source of the oscillation. Once the oscillation source is identified, the generation unit's controls will be investigated to determine how to remove the oscillating behavior.

A copy of the *Transmissions Situational Awareness Project Final Report* is included in Appendix D-1.

Available Transmission Capacity Calculation Tool

Available transfer capability (ATC) is the transmission line capacity on a given path available for purchase through Idaho Power's Open Access Same-Time Information System (OASIS). Idaho Power has traditionally calculated ATC based on a deterministic approach. Essentially, the current method assumes all commitments (generation resources and transmission service contracts) that flow through a section of transmission line are used to determine the transmission requirements. The subtraction of this value from the total transfer capability (TTC) provides the ATC of the path for a given hour. This approach is valid and useful when the variations inherent in the future generation patterns are small; however, the increasing penetration of variable resources nullifies this assumption.

A deterministic approach essentially calculates ATC based on the worst-case scenario without accounting for the variability of resources and the correlations between multiple resource uncertainties and variability. Idaho Power, in collaboration with Pacific Northwest National Lab (PNNL), developed a probabilistic-based method and tool flexible enough to allow Idaho Power to determine the ATC for any existing and future path. Different from the deterministic approach, this tool considers stochastic variations of wind generation and load and the impacts of such variations in calculating ATC.

Calculating ATC is critical to knowing how much power can be reliably transferred over the interconnected transmission network. An overestimation of ATC can jeopardize the reliability of system operation or cause unexpected congestion, while underestimated ATC can lead to inefficient transmission utilization.

The initial ATC tool has been developed and evaluated by Idaho Power. The calculations and methods have been verified; however, the software was developed without sufficient flexibility to model future system changes. Idaho Power is contracting the development of a user interface to adjust the program inputs to expand the applicability of the tool.

A copy of the CONFIDENTIAL *User Manual for Developing a Methodology and Tool to Determine Probabilistic Available Transfer Capability* is included in Appendix D-2.

Dynamic Line Rating Pilot

Transmission line capacity is typically limited by the thermal capacity of the conductor. Currently, transmission line thermal limits, or ratings, are static and based on conservative assumptions of ambient temperature, solar intensity, and wind speed. Conversely, a dynamic transmission line rating system is based on the actual or calculated conductor temperature. Idaho Power and Idaho National Lab (INL) are collaborating on a system that predicts wind speed and direction along the transmission line from an area-specific wind model using real-time weather station information located along the transmission line. The software program calculates the actual line limits based on the measured ambient conditions and wind model. A pilot system with 17 weather stations has been installed in a test area monitoring a portion of the 230-kV and 138-kV transmission lines between Hagerman, Bliss, and Glenns Ferry, Idaho.

The weather stations and data logging devices have been improved to increase their reliability and the wind modeling technique has been validated. The company’s grid operations personnel have included the dynamic line rating data when determining the proper course of action during transmission line outage conditions. Idaho Power approved a budget to expand the pilot test site to the whole length of the transmission path between Boise and Jerome, Idaho.

A copy of the CONFIDENTIAL study, *Grid System Planning for Wind: Concurrent Cooling, Increasing Transmission Capacities with Dynamic Monitoring Systems*, is included in Appendix D-3.

B. Substation and Distribution Network and Operations Enhancements

Transmission Transformer Geomagnetic Disturbance Monitoring

Idaho Power has analyzed the transmission substations in its system to determine those that may be susceptible to geomagnetic induced currents (GIC). GIC are created when a space weather event (solar storm) interacts and creates variation in the earth magnetic field. As shown in Figure 3, the variation in the magnetic field induces currents in metallic pipelines and electrical conductors. Large GIC currents flowing in the transmission conductors are sourced by and may impact the transmission connected transformers. Such an impact could depress the transmission system voltage which may result in loss of load service capability. This analysis has identified three substations that may experience GIC during a large geomagnetic disturbance (GMD). Sensors are being installed on the transformers located at these substations to confirm the presence of GIC during lower level GMD events. A copy of the CONFIDENTIAL study, *Idaho Power Company Geomagnetic Disturbance Study*, is included as Appendix D-4.

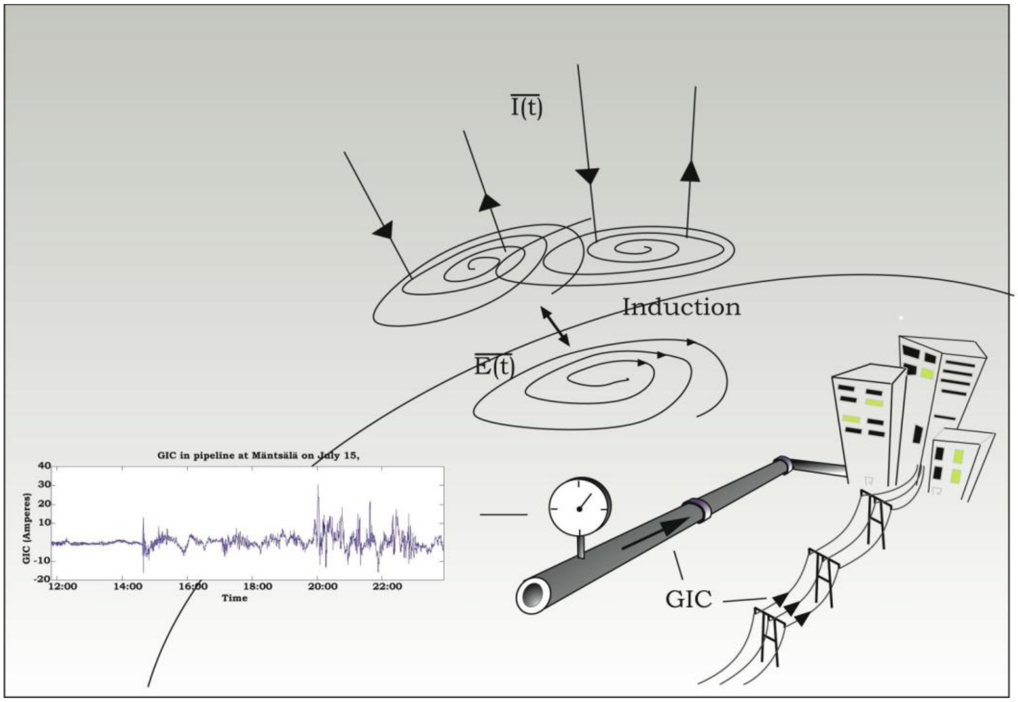

Figure 3
Geomagnetic induced currents, indicated by arrows, flowing through pipelines and transmission lines

Conservation Voltage Reduction

Idaho Power participated with 12 other utilities through the Northwest Energy Efficiency Alliance (NEEA) in a conservation voltage reduction (CVR) pilot study in 2007. This study, using statistical sampling, determined that system peak power demands and overall energy consumption can be reduced by CVR. Idaho Power is validating the benefit of the CVR program before expanding it beyond the initial study areas. AMI and other smart grid technologies now exist to validate energy savings and reduced peak demand. Idaho Power intends to analyze the CVR effects at the Alameda and Meridian substations where CVR has been implemented. Idaho Power expects to complete the CVR analysis in 2016. If the analysis confirms energy savings and reduced peak demand, Idaho Power will evaluate extending CVR measures to other Idaho Power substations.

C. Customer Information and Demand-Side Management Enhancements

Advanced Metering Infrastructure

The AMI system represents the foundation for Idaho Power's smart grid. The system uses Aclara's powerline carrier (PLC) Two-Way Automatic Communication System (TWACS®); broadband communications from each substation to the Information Technology (IT) data center; and Itron, Inc.'s Meter Data Management System (MDMS). Idaho Power has backhaul communications in place for approximately 500,000 meters. TWACS Substation Communications Equipment (SCE) is installed in 139 distribution substations, enabling two-way communications with all smart meters installed on Idaho Power's electrical distribution system. TWACS is currently collecting hourly energy consumption data and daily kilowatt-hour (kWh) and kilowatt (kW) readings for all smart meters deployed in Idaho and Oregon. The AMI system provides two-way communications to 99 percent of Idaho Power's metered retail service customers. The remaining 1 percent of metered retail service customers did not meet Idaho Power's business case requirements at the time the implementation plan was initiated.

In 2011, Idaho Power completed the installation of AMI hardware and software, a meter data management system, a metering data warehouse, and approximately 500,000 digital smart meters (including 18,000 meters in Oregon) for a total investment of $73 million. Since the project's completion, Idaho Power and its customers have realized the following benefits:

- Manual meter reading staff was reduced by 70 employees. Idaho Power continues to manually read approximately 4000 meters each month in those areas where the AMI technology was not cost justified. This represents 1 percent of Idaho Power's total metered retail service customers, but due to the remote areas in eastern Oregon and the low population densities in many of these locations, nearly 10 percent (1600 meters) of its Oregon metered retail service customers continue to be manually read.

- Billing errors due to inaccurate meter reading have been nearly eliminated.

- Billing estimates due to meter access issues have been greatly reduced.

- Customer move-out/move-in meter readings have been automated.

- Hourly energy usage is being collected daily. This greatly assists with resolving customer inquiries related to high bills.

- The installation of the AMI infrastructure has enabled Idaho Power to use the two-way PLC for demand response programs to communicate with air conditioning (A/C) cycling switches and discontinue the use of radio (paging) communication systems. Idaho Power has also conducted a pilot using the Aclara load control switches to turn off irrigation pumps for the Irrigation Peak Rewards program.

- Meter pings are being used to confirm outages and service restoration.

- Meter pings are being used to confirm active services, thereby reducing the need for a troubleman to respond in person.

- Voltage readings are being collected daily for specified locations on the distribution system to confirm adequate voltages and respond to low-voltage issues.

- Voltage readings are being collected for all locations three times a year to confirm engineering models (system peak load [summer/winter] and system low load [fall]).

- Voltage monitoring and non-communicating meters are being used to identify potential distribution system problems and respond more quickly, often before the customer recognizes the problem and calls Idaho Power's outage line.

- Communication monitoring has lead to the discovery and resolution of several cases of energy theft.

- The installation of digital subscriber line (DSL) or Frame Relay communications to distribution substations for AMI communications has enabled more stations to be equipped with Supervisory Control and Data Acquisition (SCADA) for better distribution system monitoring.

A copy of the *Advanced Metering Infrastructure (AMI) "Phase II" Project Completion Report* is included in Appendix D-5.

Customer Information System Replacement

Idaho Power implemented a new billing system, SAP's Customer Relationship and Billing (CR&B), on September 1, 2013. CR&B enables smart grid functionality for dynamic and TVP capabilities and interoperability through its open systems architecture. The CR&B implementation completed approximately 80 system integrations, including integrations with major systems, such as the AMI system, the mobile workforce management system, other customer systems, and the outage management system. CR&B enables Idaho Power to offer more flexible rate designs, including TVP to the vast majority of residential customers in the future. Peak demand is expected to be reduced as a result of customers participating in TVP programs.

Time Variant Pricing

Idaho Power is currently conducting a TVP pricing pilot in its Idaho service area. The purpose of the pilot program, named Time of Day, is to use AMI smart grid meters and infrastructure to offer customers pricing options and opportunities to reduce their bills, to evaluate customer response rates, to study changes in participant behavior, and to evaluate the revenue impact of the time-of-use (TOU) pricing plan. The findings of this study will guide how Idaho Power expands TVP offerings to the rest of its customers in Idaho and Oregon. A final report of pilot study findings is expected at the end of 2014. A status report of the study, *Time of Day Pilot Study Status Report*, is included in Appendix D-6.

Energy Use Advising Tool

The Energy Use Advising Tool (EUAT) is provided through Aclara's Energy Prism® application. This tool allows customers to access their detailed AMI usage information via the internet, supporting better-informed decisions about their energy usage and related financial impacts. The tool also allows Customer Service representatives (CSR) to access detailed AMI usage information for each customer to help educate about how and when they are using energy. An example of a customer's hourly usage is displayed in Figure 4 below. For an expanded illustration of the functionality of AMI data available to customers in EUAT/Account Manager, see Appendix D-7. Also, a project summary, *Energy Use Advising Tool – Lessons Learned*, is in Appendix D-8.

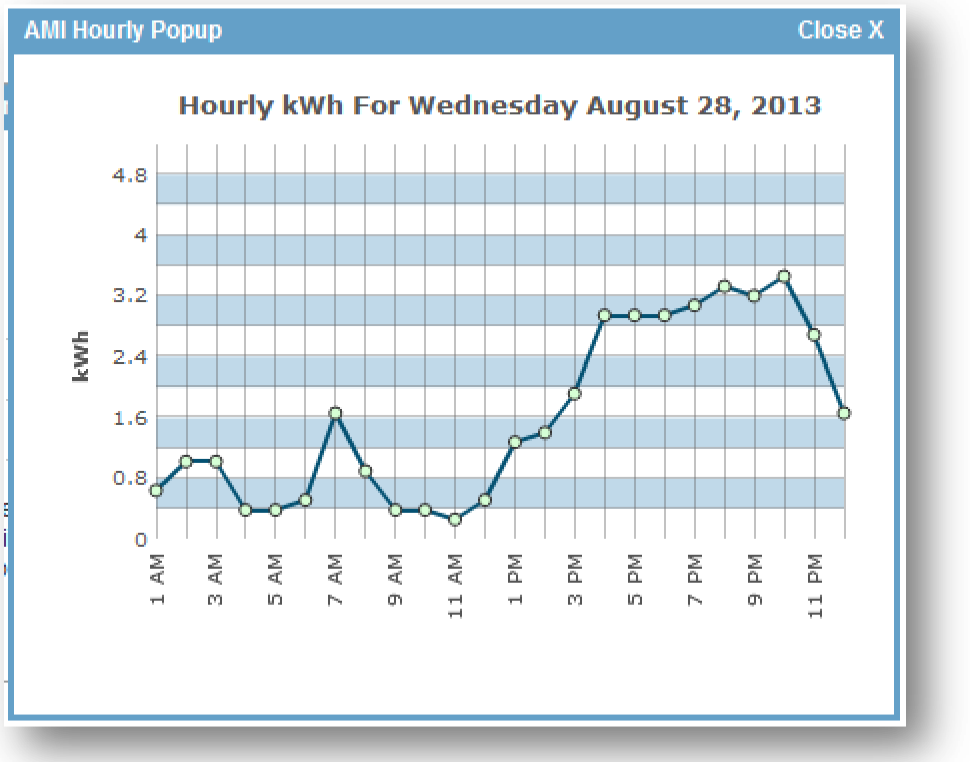

Figure 4
Customer hourly usage display in Account Manager

The EUAT was implemented in two stages. The first stage was implemented in January 2012 and provides customers and CSRs access to detailed hourly usage information and a bill-to-date view of their usage for the month at that point in time. The second stage was implemented in March 2012 and provides customers a financial comparison between the standard residential rate and the time of day rate. Currently, this feature is enabled only for those customers who are eligible for the Idaho service area Time of Day pilot. Figure 5 shows a display of a financial comparison for a customer between two available rate options.

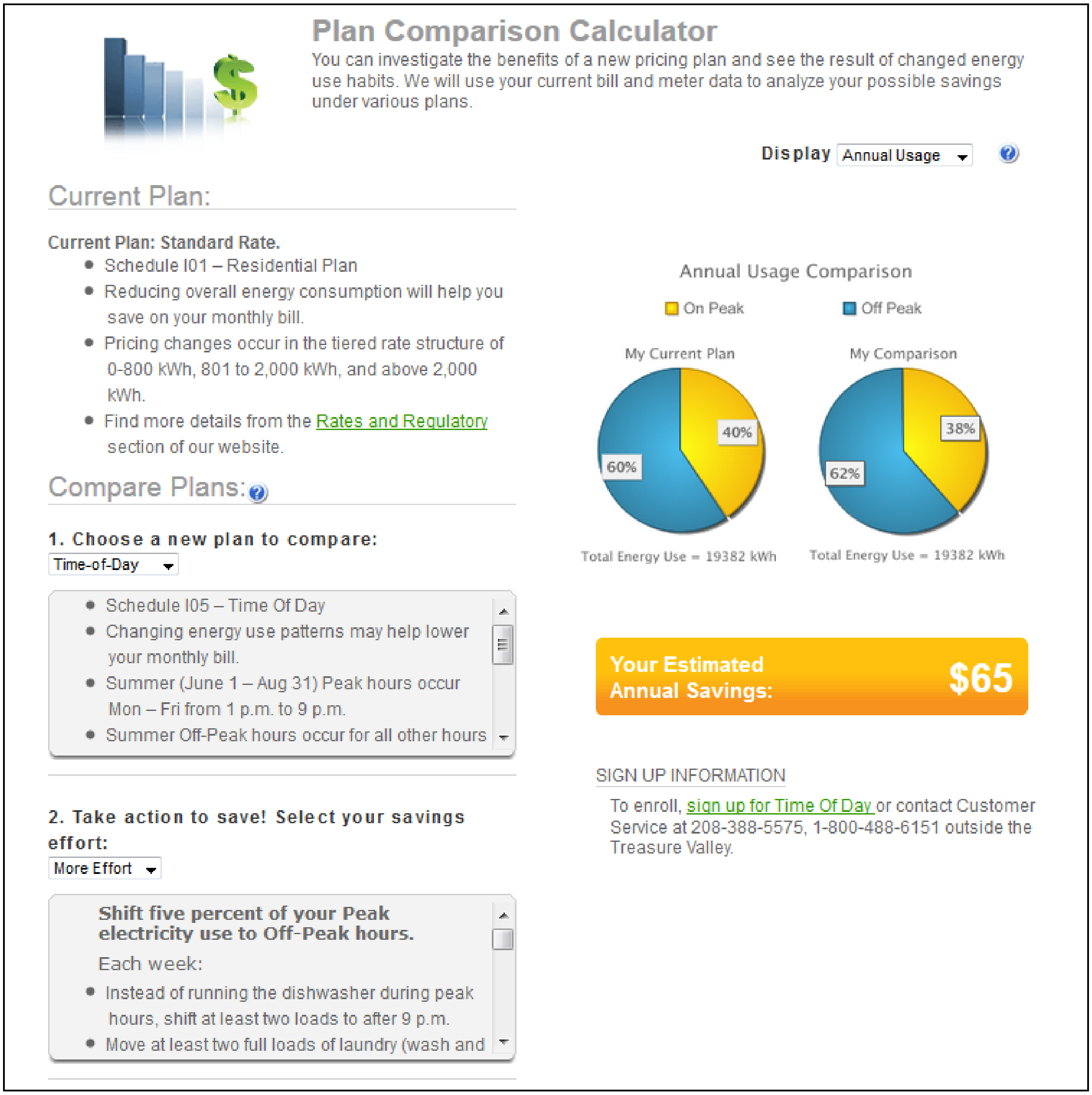

Figure 5
EUAT plan comparison calculator display

Direct Load Control

Idaho Power has offered direct load control, or demand response (DR), programs since 2004 and to all of its customer sectors since 2009. The company has offered an A/C cycling program, A/C Cool Credit; an irrigation direct load-control program, Irrigation Peak Rewards; and a commercial industrial DR program, FlexPeak Management. The A/C Cool Credit and Irrigation Peak Rewards programs utilize the smart grid technology, more specifically the PLC technology to activate load-control devices installed on customer equipment. Both programs also have used the hourly load data made possible by AMI to help determine the load reduction achieved during a DR event.

A/C Cool Credit

The A/C Cool Credit program is a voluntary, dispatchable DR program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central A/C or heat pumps on and off via a direct load-control device installed on the A/C unit. Participants receive a monthly monetary incentive for participating in the program during the summer season. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high. In 2012, Idaho Power had 36,454 program participants resulting in an estimated summer peak reduction capacity of 44.9 megawatts (MW).

PLC switches have been installed on the majority of participants' A/C units. These switches allow Idaho Power to cycle customers' A/C during a cycling event. Approximately 28,000 PLC switches are installed on customers' A/C units in Idaho Power's service area.

In 2012, Idaho Power contracted with a third-party consultant to conduct a study of the A/C Cool Credit program. The goals of this research were to verify savings can be estimated using AMI data, verify the adaptive algorithm is working as designed, estimate kW reductions at different temperatures and cycling strategies, create a predictive model for planning purposes, and test the comfort impacts of higher cycling strategies to find the optimum curtailment strategy that maximizes kW results with minimum comfort impacts. The consultant concluded that AMI data is reliable, cost effective, and produces more immediate feedback than gathering data through end-use loggers and they recommended using only AMI data for all subsequent analyses of the A/C Cool Credit program (see page 12 of the study). An example of the usefulness of AMI data in program evaluation, a copy of this study titled *A/C Cool Credit Program Research Results* is in Appendix D-9.

Irrigation Load Control

Idaho Power predominantly uses cell phone and web-based technology to enable the company's Irrigation Peak Rewards program. The objective of the Irrigation Load Control (ILC) Pilot is to use grid-enabled PLC communication to activate load-control devices on agricultural irrigation service locations to turn off irrigation pumps during program events. As part of the ARRA SGIG, Idaho Power began conducting a pilot using grid-enabled PLC communication that would provide a less expensive and more secure environment for program communication. The company currently has 133 AMI-enabled load-control switches installed on participants' service points. To use the load-control switches, Idaho Power added a transformer to the switches and tested the communications to these devices. Because the company has not had any load-control events since 2010 with this program, the actual performance of these switches has not been tested.

Irrigation Peak Rewards

The Irrigation Peak Rewards program is a voluntary program available to agricultural irrigation customers. The purpose of the program is to serve as a peaking resource during times of extreme load on the Idaho Power system by turning off participants' irrigation pumps with the use of one or more load-control devices during the program season, June 15 through August 15. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. In 2012, Idaho Power had 2,433 service points participating, accounting for approximately 340 MW of load reduction.

D. Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool

The Idaho Power SGIG funded the Renewable Integration Tool (RIT) project. The RIT project was intended to develop tools to allow grid operators and power supply transaction specialists to efficiently and reliably integrate variable renewable resources with traditional generation resources.

To account for the variability in generation resources, the RIT project integrated variable renewable resources from large generation interconnections and *Public Utility Regulatory Policies Act of 1978* (PURPA) wind projects. The project's goal was to yield three wind forecast intervals: a short-term demand forecast, an enhanced regulating margin forecast, and a spinning reserve forecast.

The initial plan for the RIT project was to purchase an off-the-shelf variable generation balancing tool that required an external wind forecast. However, by evaluating different options, Idaho Power determined an internally produced forecast was more accurate than third-party forecasts. After discussing options with other utilities and research facilities, Idaho Power created its own forecast tool for the Idaho Power service area using weather research and forecast (WRF) data from the University of Arizona.

The pre-schedule and real-time forecasts were successfully implemented and are providing forecast values that more accurately predict wind generation. Idaho Power determined the one-hour wind forecast was unable to forecast more accurately than persistence without significant additional effort. (In this case, the term persistence means using the previous observed condition.) The short-term demand forecast was successfully implemented and is providing forecast values at intervals not previously available. Calculations for the regulating margin and spinning reserve forecasts were implemented and incorporated into the more accurate short-term demand forecast. However, because efforts to develop a wind forecast for intervals of less than one hour were unsuccessful in improving on persistence, the full capabilities of this tool were not realized.

The following were significant challenges for the project:

- **Lack of observed weather data at the surface and hub height.** There was a lack of meteorological towers near wind parks, and measured wind speeds at existing towers did not correlate well to observed power generation.

- **Lack of observed power data except at interconnections.** The power generated at each wind park is not always readily available, as the metered value available is the sum of generation feeding into the point of connection to Idaho Power's network. For example, the Mountain Air wind park near Hammett, Idaho, has six parks but only one metered power value; therefore, Idaho Power is unable to correlate power at each geographic location to wind speeds.

- **Terrain**. The existing high resolution of 1.8-kilometers (km) does not accurately model winds of turbine locations on mountainous terrain. High-frequency updates (RUC40) are at 40-km resolution, but wind speeds forecasted for each point available are influenced by terrain that is typically very different from the terrain where the turbines are located. Observed power production and weather forecast patterns in locations like Rockland wind park, near Pocatello, Idaho, are not well understood. Because of the proximity of Idaho Power's service area to the west coast and the resulting limited observation data, forecasts are more than one day out, and it is difficult to time weather events.

- **Model timing.** The existence of ramp ups and drops in power can generally be forecasted, but forecasting the timing of events greater than 24 hours out is more difficult.

- **Contracts.** Power purchase contracts with wind parks were created before the needs of accurate wind power forecasting were known or considered; therefore, some of the contracts do not include requirements to provide data beneficial to generating more accurate forecasts for the wind parks.

The RIT project was completed within the 18-month schedule and under budget. A copy of the study, *Renewable Integration Tool Project Summary*, is included in Appendix D-10.

Current Distributed Resources on Idaho Power system

Idaho Power has contracted to receive distributed generation from 103 PURPA projects with a combined nameplate rating of 778 MW. Of these 103 projects, 102 projects with a nameplate rating of 774 MW are online and delivering distributed energy to Idaho Power at various delivery points across the electrical system. This distributed online generation is comprised of eight Biomass projects (23.19 MW), four cogeneration projects (30.9 MW), 63 small hydro projects (143.2 MW), and 27 wind projects (576.9 MW). Of these projects, four small hydro projects (14.89 MW) and one wind project (3 MW) are physically located within the state of Oregon.

There are currently 381 active participants in Idaho Power's net metering service, with an additional 19 new system applications in progress. The majority of active interconnected systems are solar photovoltaic (302), followed by wind (69), hydro (8), and other (2). Nameplate capacity of active systems currently totals 2.719 MW. Of the 381 active systems, 11 are in Oregon (9 solar, 2 wind) representing 0.1627 MW of capacity.

Maps showing non-Idaho Power generation and net metering projects are included in Appendix D-11.

E. General Business Enhancements

Advanced Metering Infrastructure Communications

Idaho Power communicates with its AMI meters using PLC technology. This technology has a narrow bandwidth and allows Idaho Power to collect customers' hourly meter data, reset demand, and operate limited DR devices (i.e., on/off switches for A/C compressors and irrigation pumps). For the majority of substations, commercial third-party broadband communications were installed from the substation to the IT data center for backhaul communications.

Idaho Power Enterprise Data Warehouse

The EDW provides an analytic database to store meter and customer data. The first phase of this project was completed in November 2011 and entailed collecting, organizing, and providing meter data for reporting and analysis. The second phase will provide customer data extracted from CR&B for reporting and analysis. This phase began with the implementation of CR&B on September 1, 2013.

Idaho Power currently has daily and hourly energy-use data stored for all AMI metered service points and has implemented the following:

- Customer portal viewing of energy use via the web.
- Providing data for an internal load analysis and developing broader system analysis capabilities.
- Energy-use data is available to internal functions with business access (customer service, engineering, energy efficiency, system planning, etc.).

III. FUTURE SMART GRID INVESTMENTS

This section describes smart grid investments and applications to be undertaken over the next five years (including pilots and testing).

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Oscillation Monitoring Pilot

Software is under development by Dr. Venkatasubramanian at Washington State University that will analyze PMU data for abnormal frequency oscillations. The software identifies the frequency of the modes of oscillation and their associated damping ratio (or tendency for oscillations to dissipate over time) to help identify potential dynamic stability issues. With sufficient monitoring locations, it will also identify the generator(s) that are initiating the oscillation.

An oscillation has been identified through the analysis of Idaho Power's PMU data. However, the source of oscillation cannot be determined from the present number of PMU locations. A capital budget allocation has been approved for the installation of additional PMUs at five generation plants in order to determine the source of oscillation. Once the oscillating generator(s) are identified, their controls will be adjusted to remove the instability and improve system reliability.

The *Summary of OMS Results from August 1, 2013 through August 14, 2013* is included in Appendix D-12.

Transmission Situational Awareness Voltage Stability Monitoring Pilot

Dr. Venkatasubramanian at Washington State University is also developing software which will analyze PMU data to determine the onset of voltage instability. When fully developed, it is intended to provide transmission grid operators an early warning that the system is approaching an unstable voltage operating condition. Such an advanced warning will allow the operators to adjust the system and maintain system reliability. This software development is presently under contract.

B. Substation and Distribution Network and Operations Enhancements

Substation Fiber-Based Protection and Control Pilot

Present technology and practices require numerous multi-conductor copper cables to connect pieces of substation yard equipment to the control building for protection and control. Installing fiber optic cables to these devices may reduce the substation construction and operating costs. Fewer and smaller fiber cables resulting in fewer terminations and smaller cableways reduce costs. Idaho Power and Schweitzer Engineering Laboratories (SEL) are collaborating to develop the digital equipment needed to implement a highly reliable substation fiber optic network. The pilot project will install a system that parallels an existing substation protection and control system to demonstrate the reliability and viability of this technology. A capital budget allocation has been approved for the installation of this equipment in 2014.

C. Customer Information and Demand-Side Management Enhancements

Customer Relationship Management

When Idaho Power's ARRA SGIG allowed the company to purchase and install its new SAP CR&B system, the future implementation of a Customer Relationship Management (CRM) system became possible. The CRM system will pull data from a variety of centralized data sources (hourly and monthly meter usage data, customer information, demographics, program data, etc.) with the ability to query/report both on a formal and ad hoc basis. This system will allow Idaho Power to manage and track energy efficiency and customer relations with the ultimate goal of increasing the effectiveness of the company's energy efficiency efforts and promoting the use of its Account Manager customer outreach tool. The company will explore the implementation of the CRM system as the CR&B product becomes more mature. A copy of the *Customer Relationship Management – Lessons Learned* document is in Appendix D-13.

D. Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool: Potential Future Projects

Idaho Power is considering the following projects for potential improvements of the RIT.

- **Incorporating new forecasting model types.** Idaho Power is continuously looking for improvements to the current weather model, new weather models, and techniques to improve the wind forecast.
- **Early warning system based on physical indicators.** To detect approaching changes in wind speeds through the use of observations upstream of wind parks or other real-time meteorological gages and create an early warning system based on these observations.
- **Additional high-speed cutout warnings.** To develop an algorithm to apply to all wind parks that would use reasonable high-speed cutout indicators.
- **Forecast refinements.** Investigate several other weather parameters to determine correlations to wind power. Some of these correlations are directed at detecting ramps or weather fronts, and others are related to generation accuracy.
- **Thunderstorm detection.** Thunderstorms moving through the system cause rapid spikes in system generation; however, exact thunderstorm prediction is difficult. Create a warning system that will let operators know when thunderstorms and resulting generation spikes are possible.
- **Interactive user forecast adjustments.** To allow operators to manually adjust the real-time forecast to match the current state of the system and correct errors.
- **Missed forecast analysis.** Developing a forecast-analysis log is essential to identifying missed forecast events and determining how to create better future forecasts.
- **Real-time turbine availability and known maintenance schedules.** Better incorporate real-time turbine availability and known maintenance schedules of third-party providers into the wind forecast.
- **Streamlining the addition of new wind parks.** The addition of new wind parks into the RIT, although better, is still a slow process.
- **Short-term demand forecast.** The mid- and short-term demand forecasting tool will improve over time as other weather variables are added to the model.

- **Reserve calculations.** If a short-term wind forecast method becomes available, the values would be included in regulating margin and reserve calculations.

E. General Business Enhancements

Implementation of Automated Connect/Disconnect through the AMI System

Approximately 15,000 residential service locations in Idaho Power's total service area have multiple actual connect/disconnect events each year. The company intends to replace the current meters at these locations with new meters equipped with internal service connect/disconnect devices. Meters removed from service will be used for new business and maintenance activities, reducing the need to purchase additional standard meters. The initial cost of the meters is approximately $105 each; the return of the current in-service meters will defer the purchase of new non-service connect/disconnect meters at a cost of $67 each. The company believes the net difference of $38 will be offset by the elimination of multiple annual site visits for actual service connect or disconnect.

Implementation steps anticipated for the 2014-2015 time period:

1. Obtain OPUC tariff approvals for the process changes required to implement automated connect/disconnect capability.
2. Purchase 15,000 AMI meters with an internal service connect/disconnect capability.
3. Install the new service connect/disconnect meters on select service points as service reconnects occur.
4. Return the meters removed for the project to normal meter stock.
5. Implement the necessary IT system configuration to automate the connect/disconnect process.
6. Implement the automated connect/disconnect process.

Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality

Sentry devices have the ability to identify and report outages and line device operations. Idaho Power has more than 1,400 Sentry devices strategically installed across its distribution system. The company is currently testing the AMI integration with the Sentry system to initiate an AMI meter interrogation from Sentry activity. This integration will provide an automated scoping of outages based on the Sentry notification of line equipment operations. This automation will eliminate the need for a manual initiation of meter interrogation for outage scoping in many cases. Idaho Power plans to complete testing and pilot this functionality in 2014.

Ability of the AMI System to Control Line Devices

Idaho Power is in the early stages of feasibility testing the automated control of distribution capacitor banks.

Replace the Existing Outage Management System

In 2010, Idaho Power started the effort to select a vendor and implement a new OMS to replace the existing OMS that is several years old and no longer supported by the original vendor. Following a market search and analysis of several request for proposals (RFP), the company contracted with General Electric to install their Power On OMS product. The project was progressing until early 2012 when critical Idaho Power resources assigned to the OMS project were needed to support the higher priority CR&B project. In fall 2012, Idaho Power suspended the OMS project until late 2014 or early 2015.

Upgrade the Mobile Workforce Management System

Idaho Power currently uses CGI's PragmaCad mobile workforce management system. This system is integrated with several other major systems necessary to automate and support field service personnel. The version of PragmaCad in operation at the company is several years old, and although still supported by CGI, it is multiple versions behind the latest release supplied by CGI. The latest release has increased functionality that promises to improve the efficiency of field personnel. Idaho Power plans to upgrade the existing version of PragmaCad beginning in 2015.

IV. Smart Grid Opportunities and Constraints

This section lists and describes other smart grid opportunities the utility is considering for investment over the next five years and any constraints that affect the utility's investment considerations.

A. Transmission, Substation, Operations, and Customer Information Enhancements

DOE ARRA Smart Grid Grant projects

Having just completed a substantial portion of the DOE ARRA smart grid grant projects in 2013, Idaho Power plans to evaluate the grant project outcomes and update its smart grid approach in 2014.

Hourly Customer Usage Data

Idaho Power has begun to use hourly customer usage data in a variety of ways to enhance and evaluate its customer information and demand-side management (DSM) activities. As the hourly customer usage information becomes a more complete data set, these data will be valuable in energy efficiency and DR program evaluation, program promotion, and customer communications. The usage information is being used for some program evaluation, high bill complaints, and TOU program analysis.

Future Time Variant Pricing

Based on the outcome of the current Time of Day Pilot Study described earlier, Idaho Power will consider offering a TOU rate option to its Oregon residential customers who have AMI meters.

Home Area Network

Idaho Power is not currently engaging in any home area network (HAN) technologies. The AMI meters installed are not equipped with wireless HAN communication capabilities. Due to the infancy of HAN technologies and a lack of standard communication protocols, Idaho Power has chosen to limit energy management services beyond the meter. Idaho Power provides energy management advice and data supporting third-party energy management systems.

B. Evaluations and Assessments of Smart Grid Technologies

This section describes evaluations and assessments of smart grid technologies and applications the company has undertaken or plans to undertake.

Photovoltaic and Feeder Peak Demand Alignment Pilot

Idaho Power has installed three solar-intensity monitoring stations along a distribution feeder to determine the impact of installing photovoltaic (PV) panels to maximize PV output with feeder peak demand. Each monitoring station is comprised of three solar-intensity monitors with the following orientation: south for maximum annual energy (typical customer orientation), west for maximum output coincident with feeder peak demand, and horizontal for the global solar-intensity reference.

Volt/VAr Management Technology Evaluation

In order to service customers with a voltage within plus or minus 5 percent of nominal, Idaho Power presently operates a substation based volt/volt ampere reactive (VAr) control system. The substation unit is able to control the substation feeder capacitor banks via one-way communications. This project will evaluate the benefits of a central server-based Volt/VAr Management System (VVMS) combined with bidirectional communications.

C. Smart Grid Pilots and Programs

Although not organized or managed as a specific project, Idaho Power monitors smart grid-related technology advancements, related articles, research, reports, demonstration projects, and demonstration results as applicable. As energy generation, consumption, and management technologies continue to improve, additional opportunities for the deployment of smart grid-enabled devices/appliances will become available. As these technologies continue to improve, it may be possible to create new products and services to help Idaho Power manage and optimize its system and help its customers manage their energy use and consumption. The areas being monitored include the management and integration of electric vehicles, distributed resources, and microgrids.

D. State of Key Technologies

Having recently completed major smart grid projects funded through the DOE ARRA grant, the company is monitoring the implementation of those projects and is planning to evaluate outcomes and issues. This work will compel Idaho Power to look at new key technologies and determine what to research further.

V. TARGETED EVALUATIONS

Because this is the first annual report, no OPUC-approved stakeholder recommendations have yet been received that require evaluation.

VI. RELATED ACTIVITIES

This section discusses activities that relate to smart grid operations.

A. Cyber and Physical Security

Idaho Power has developed system security plans (SSP) for every SGIG project. The company has continued to use the same approach as documented in *Idaho Power's Smart Grid Plan* of October 2011 and, as before, no smart grid projects or plans fail to conform to Idaho Power's cyber security standards. Security language is included in RFPs and contracts for all vendor, software, and device selections. Idaho Power SSPs address Physical Security controls of the assets. All plans conform to Idaho Power's physical security standards.

B. Privacy

Idaho Power is committed to protecting the company's systems and the data within them as stated in its *Corporate Security Policy* and evidenced by the company's Corporate Security program. For confidential data, such as customer information and energy usage data, Idaho Power limits access using a need-to-know approach enforced by role-based access controls for employees and contractors. The policies and controls undergo periodic reviews to ensure they support applicable mandates and guidance.

Idaho Power recognizes that new risks are emerging from smart grid technologies, both from the increase in data and the increasing interconnectivity of systems. To stay current on these, Idaho Power has joined collaborative public–private partnerships, such as the National Institute of Standards and Technology Smart Grid Interoperability Panel Cyber Security Working Group (NIST SGIP CSWG).

Idaho Power customers can access their energy usage data electronically via a registered and password-protected login (Account Manager) on the Idaho Power website. Customers can also request Idaho Power provide hard-copy usage information via fax, email, or mail.

Idaho Power can provide customer usage data to entities other than the customer only under one of the following conditions:

- Receipt by Idaho Power of a court-ordered subpoena
- Presentation by a third party of legal documentation substantiating the power of attorney for the customer of record
- Receipt by Idaho Power of written authorization from the customer of record identifying the third party to whom information is to be released and specifying the information to be released
- Notification by a public utility commission that the customer of record has filed a complaint

In addition to the above conditions under which information for an individual customer may be provided, Idaho Power has several contractual business relationships with third parties for the procurement of services essential to the operation of the business (e.g., bill print services) that are subject to non-disclosure agreements and data security requirements.

C. General Customer Outreach and Education

Overview

Over the past six years as AMI installation has been completed, Idaho Power has provided residential, small commercial, and irrigation customers self service options at www.idahopower.com. The self-service options help customers learn about energy, how they are using it, and how they can save energy. This technology gives customers the ability to view their hourly and monthly meter data with additional energy tools and analytics technology. Most residential, small commercial, and irrigation customers can also view their meter data at www.idahopower.com and use self-service features and information 24 hours a day, 7 days a week.

Idaho Power employees have the ability to answer residential and small commercial customers' questions about detailed energy usage. This specific data is available for TVP rate structure (residential), while using features in the CSR tool, the Meter Highlights tool (with bill-to-date functionality), and the Rate Comparison tool for residential customers. The CSR tool will allow authorized, internal employees to see the same data as the Internet self-serve customer. This helps the CSR to consult with the customer about energy usage and high bill complaints.

Events

The company participates in numerous home and garden shows, energy fairs, parade of homes, and other public events. At these events, Idaho Power employees cover a wide range of information, answer customer questions, and assist customers in registering for the company online self-help services. The company also promotes www.idahopower.com, using the EUAT to help customers learn more about using energy, tips and ideas to save energy, energy efficiency program information, information about smart meters, payment options, and general company information.

Communications

Idaho Power communicates frequently with customers through a variety of channels, including, but not limited to, billing statements, bill messages, bill inserts, *Customer Connection* articles, customer letters, doorknockers, postcards, brochures, web content at www.idahopower.com, hold messaging on the company's 1-800-488-6151, social media using Facebook, public events, and customer visits.

Electric Vehicles (EV)

Idaho Power customer representatives continue to develop ongoing relationships with auto dealerships about EV. The purpose of these relationships is to establish a point of contact, build a relationship, gather information, and identify partnership opportunities with Idaho Power and the auto dealer's mutual customers on the best ways to use electricity.

Idaho Power continues to monitor EV technology and EV saturation in the service territory. Idaho Power has purchased three plug-in vehicles for fleet use evaluation. Since Idaho Power's overall system peak is typically in the late afternoon in the summer, shifting any new EV charging load to off peak night hours would benefit the system. Idaho Power provides information to current electric vehicle owners about the benefits of participating in the Time of Day pilot pricing plan. At this time the pilot is open only to customers in Idaho. A copy of an informational brochure is attached in Appendix D-14. There continues to be a fairly low saturation of EV in the Idaho Power service area. The Company estimates there are under 200 residential customers on our system that own an electric vehicle.

Summary

Idaho Power has successfully leveraged the functionality of AMI and especially the hourly meter data to enable the majority of its customers to learn more about their energy usage and how to use energy wisely. The company has used events and other channels to provide customers relevant information on a frequent basis about energy efficiency, company and program information, and updates about smart metering. Idaho Power also sends a new customer welcome letter inviting them to visit www.idahopower.com to learn more about their energy usage and to register as Account Managers.

VII. CONCLUSION

With the recent implementation of AMI meters for all customer classes, as well as the deployment of a new customer billing system that enables hourly billing, Idaho Power has made significant progress towards implementing a smarter grid for its system. Idaho Power customers now have online access to hourly usage information in addition to the ability to participate in demand response offerings.

Even so, Idaho Power anticipates significant smart grid efforts in the next five years. With the completion of the ARRA SGIG project, Idaho Power will evaluate the capabilities of it new smart grid infrastructure and refresh its smart grid vision and strategies. New research to enhance the transmission and substation infrastructure, and to improve system integration of renewable and distributed resources, is planned. New offerings for customers, including TVP options, are being evaluated. The Company also plans to upgrade its outage management system and the mobile workforce management systems to improve operational reliability and efficiency.

Idaho Power is dedicated to continuing efforts toward a smart grid system with the goal of a more efficient, reliable, and safe system which provides benefits and options to customers.

IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix A

Newspaper ad and email solicitation

Share Your Ideas About Smart Grid

Idaho Power is currently compiling its first annual smart grid investment report for submission to the Public Utility Commission of Oregon (OPUC). As part of the annual report, we are seeking public input and contributions of information and ideas on smart grid investments and applications. To share your ideas, please email smartgrid@idahopower.com or call Darlene at (208) 388-2505. We are taking public input between Aug. 21 and Sept. 18, and a summary of customer submissions will be provided to the OPUC with Idaho Power's report.

The smart grid represents energy innovation, leveraging a combination of improvements that enhance customer service, power reliability, availability of renewable resources, and opportunities for time, energy and cost savings. In 2010, Idaho Power was awarded a Smart Grid Investment Grant (SGIG) by the U.S. Department of Energy. We submitted our smart grid plan to the OPUC in 2011.

For more information about smart grid, and Idaho Power projects funded by the SGIG, go to **www.idahopower.com/smartgrid**.

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Nemnich, Darlene

From: Nemnich, Darlene
Sent: Wednesday, August 21, 2013 2:15 PM
To: 'dockets@oregoncub.org'; Dockets; 'oregondockets@pacificorp.com'; 'greg@richardsonadams.com'; 'stephanie.andrus@state.or.us'; 'erik.colville@state.or.us'; 'pge.opuc.filings@pgn.com'; 'bryce.dalley@pacificorp.com'; 'mjd@dvclaw.com'; 'megan@rnp.org'; 'wendy@nwenergy.org'; 'bob@oregoncub.org'; 'jdj@racinelaw.net'; 'judy.johnson@state.or.us'; 'catriona@oregoncub.org'; Nordstrom, Lisa; 'elo@racinelaw.net'; 'dockets@mcd-law.com'; 'dreading@mindspring.com'; 'peter@richardsonadams.com'; 'ias@dvclaw.com'; 'dws@r-c-s-inc.com'; 'stephens@eslerstephens.com'; 'mec@eslerstephens.com'; 'doug.tingey@pgn.com'; 'sarah.wallace@pacificorp.com'; 'tony@yankel.net'; 'dockets@rnp.org'; 'brittany.andrus@state.or.us'; 'kacia.brockman@state.or.us'; 'betseesteb@qwest.net'; 'renee.m.france@doj.state.or.us'; 'jravenesanmarcos@yahoo.com'; 'nelson@thnelson.com'; 'vijay.a.satyal@state.or.us'; Bearry, Christa; Bryant, Jan; 'john@grid-net.com'; 'gordon@oregoncub.org'; 'rfrisbee@si-two.com'; 'maury.galbraith@state.or.us'; 'richard.george@pgn.com'; 'royhemmingway@aol.com'; 'pkeisling@gmail.com'; 'jess@caporegon.org'; 'adam@mcd-law.com'; 'douglas.marx@pacificorp.com'; 'wendy@mcd-law.com'; 'michelle.mishoe@pacificorp.com'; 'elaine.prause@energytrust.org'; 'john.volkman@energytrust.org'; 'michael.weirich@state.or.us'; 'woods@sustainableattorney.com'; Youngblood, Mike
Cc: White, Tami; Reinhardt-Tessmer, Jennifer
Subject: Comments solicited for UM 1460 Smart Grid Report - Idaho Power Company
Attachments: Smart Grid Ad Idaho Power Company.pdf

Parties to Docket UM 1460, UE 233 and LC 58,

Idaho Power will be submitting its first annual smart grid investment report to the Public Utility Commission of Oregon on October 1, 2013. As part of the annual report Idaho Power is seeking public input and contributions of information and ideas on smart grid investments and applications through September 18. To share your comments and ideas please email smartgrid@idahopower.com or call Darlene at (208) 388-2505.

Public input is being solicited through advertisements in the *Argus Observer* and *Hells Canyon Journal* newspapers. A copy of the advertisement is attached.

For more information about smart grid, and Idaho Power projects funded by the Smart Grid Investment Grant awarded to Idaho Power by the U.S. Department of Energy, go to www.idahopower.com/smartgrid.

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IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix B

Status of Smart Grid Initiatives

STATUS OF SMART GRID INITIATIVES

II. STATUS OF CURRENT SMART-GRID INVESTMENTS	**STATUS**
A. Transmission Network and Operations Enhancements	
Transmission Situational Awareness Project	Complete/In Use
Available Transmission Capacity Calculation Tool	In Use/Under Development
Dynamic Line Rating Pilot	Pilot/Under Development
B. Substation and Distribution Network and Operations Enhancements	
Transmission Transformer Geomagnetic Disturbance Monitoring	In Use/Under Development
Conservation Voltage Reduction	In Use/Under Development
C. Customer Information and Demand-Side Management Enhancements	
Advanced Metering Infrastructure	Complete/In Use
Customer Information System Replacement	Complete/In Use
Time Variant Pricing	Pilot
Energy Use Advising Tool	Complete/In Use
Direct Load Control	
A/C Cool Credit	Ongoing
Irrigation Load Control	Ongoing
Irrigation Peak Rewards	Ongoing
D. Distributed Resource and Renewable Resource Enhancements	
Renewable Resources: Renewable Integration Tool (RIT)	Complete/In Use
Current Distributed Resources on Idaho Power System	Ongoing
E. General Business Enhancements	
Advanced Metering Infrastructure Communications	Complete/In Use
Enterprise Data Warehouse	Under Development
III. FUTURE SMART-GRID INVESTMENTS	
A. Transmission Network and Operations Enhancements	
Transmission Situational Awareness Oscillation Monitoring Pilot	Pilot/Under Development
Transmission Situational Awareness Voltage Stability Monitoring Pilot	Pilot/Under Development
B. Substation and Distribution Network and Operations Enhancements	
Substation Fiber-Based Protection and Control Pilot	Pilot/Under Development
C. Customer Information and Demand-Side Management Enhancements	
Customer Relationship Management	Planned
D. Distributed Resource and Renewable Resource Enhancements	
Renewable Integration Tool (RIT): potential future projects	Under Evaluation

E. General Business Enhancements	
Implementation of Automated Connect/Disconnect through the AMI System	Planned
Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality	Under Evaluation
Ability of the AMI System to Control Line Devices	Under Evaluation
Replace the Existing Outage Management System	Planned
Upgrade the Mobile Workforce Management System	Planned
IV. SMART-GRID OPPORTUNITIES AND CONSTRAINTS	
A. Transmission Network and Operations Enhancements	
Hourly Customer Usage Data	Ongoing
Future Time Variant Pricing	Under Evaluation
Home Area Network	Under Evaluation
B. Evaluations and Assessments of Smart-Grid Technologies	
PV and Feeder Peak Demand Alignment Pilot	Pilot/Under Development
Volt/VAr Management Technology Evaluation	Under Evaluation
C. General Customer Outreach and Education	
Events	Ongoing
Communications	Ongoing
Electric Vehicles	Ongoing

Key:

- **Complete/In Use** – a project that was completed and is now being used
- **Ongoing** – did not necessarily start as a project but rather as a general effort or program and is now being used or offered to customers on an ongoing basis
- **Under Development** – for projects that are not complete at this time
- **Pilot** – a limited scope installation to prove the technology application in the Idaho Power system
- **Planned** – initiative that is included in five-year plan and budget
- **Under Evaluation** – the technology or concept is being evaluated and is not at the planned or pilot stage yet

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2013 SMART GRID REPORT

Appendix C

Acronym List

SMART GRID REPORT ACRONYM LIST

A/C	Air Conditioning
AMI	Advanced Metering Infrastructure
ARRA	American Reinvestment and Recovery Act
ATC	Available Transfer Capability
CIS	Customer Information System
CR&B	Customer Relationship and Billing
CRM	Customer Relationship Management
CSR	Customer Service Representative
CVR	Conservation Voltage Reduction
DOE	Department of Energy
DR	Demand Response
DSL	Digital Subscriber Line
DSM	Demand-Side Management
EDW	Enterprise Data Warehouse
EUAT	Energy Use Advising Tool
EV	Electric Vehicle
GIC	Geomagnetic Induced Currents
GMD	Geomagnetic Disturbance
HAN	Home Area Network
ILC	Irrigation Load Control
INL	Idaho National Lab
IT	Information Technology
km	Kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
MDMS	Meter Data Management System
MW	Megawatt
NEEA	Northwest Energy Efficiency Alliance
NIST SGIP CSWG	National Institute of Standards and Technology Smart Grid Interoperability Panel Cyber Security Working Group
OASIS	Open Access Same Time Information System
OMS	Outage Management System
OPUC	Public Utility Company of Oregon
PLC	Power Line Carrier
PMU	Phasor Measurement Unit
PNNL	Pacific Northwest National Lab
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RD&D	Research, Development and Deployment
RFP	Request for Proposal
RIT	Renewable Integration Tool
SCADA	Supervisory Control and Data Acquisition

SCE	Substation Communications Equipment
SEL	Schweitzer Engineering Laboratories
SGIG	Smart Grid Investment Grant
SSP	System Security Plans
TOD	Time-of-Day
TOU	Time-of-Use
TTC	Total Transfer Capability
TVP	Time Variant Pricing
TWACS®	Two-Way Automated Communication System
VAr	Volt Ampere Reactive
VVMS	Volt/VAr Management System
WECC	Western Electricity Coordinating Council
WISP	Western Interconnection Synchrophasor Project
WRF	Weather Research and Forecast

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Appendix D-1

Transmissions Situational Awareness Project Final Report

Transmission Situational Awareness Project

Final Report

January 2013

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TRANSMISSION SITUATIONAL AWARENESS PROJECT

Background

Original Scope

In April 2010, the United States (US) Department of Energy (DOE) awarded Idaho Power Company (IPC) a Smart Grid Investment Grant (SGIG). IPC's grant application included many Smart Grid-related projects, including a Transmission Situational Awareness (TSA) project. In August 2011, IPC updated the SGIG Project Execution Plan (PEP) new description for the Transmission Situational Awareness (TSA) project read as follows:

> The TSA tool project will enable Phasor Measurement Unit (PMU) data availability from system grid-level substation buses operating above 200 kilovolt (kV) to be sent to a central phasor data concentrator located in Boise, Idaho. Data from the IPC PMUs will be combined with data from regional PMUs to provide extensive coverage of the IPC backbone transmission grid and information for the regional grid transmission system. IPC will send PMU data to the EMS system and system state estimator, along with proper dispatch and planning data displays. The PMU installation will enhance IPC and regional electric grid situational awareness, operations, system protection, and system efficiency and reliability.
>
> The first phase of the project will install and enable hardware to measure the synchronized phasor information. Digital communication infrastructure will be added at three locations to provide PMU data transport capabilities, along with communication circuits to PMUs. The PMU data concentration and archive system will be designed to process and store the PMU data.

Assignment of Work

Communication Upgrade

IPC selected Intermountain Tower Specialists, Inc., located in Orem, Utah, to install the communication upgrade equipment at Declo, Hansen Butte, and American Falls. Intermountain Tower Specialists, Inc., was one of three communication contractors to submit bid packages. All equipment and other materials were furnished by IPC. IPC employees commissioned the new circuits and performed the transfer of the communication circuits from the exising system to the new system.

PMU Installation

IPC employees performed all engineering, design, and installation work . Schweitzer brand equipment was selected for the PMUs and the phasor data concentrator (PDC). The decision to use Schweitzer equipment was based on experience; Schweitzer is IPC's preferred provider for all station relay and control equipment which is beneficial for employee training, replacement parts, equipment warranties, and pricing.

Data Storage

IPC's Information Services department and the SGIG project team concluded the PMU data could be stored on IPC's already existing corporate data storage. Using the corporate system for data storage provided regular backed-up capability and proper security. The storage capacity would be monitored and upgraded by Information Services as necessary. Thus, purchasing a server for storaging PMU data collected by the PDC was not required.

Decisions Made

As part of a seperate Smart Grid grant, the Western Electric Coordinating Council (WECC) is developing applications to display synchrophasor data. These applications will help IPC employees use and analyze PMU data. s sWECC will provide training for these applications via online classes.

The DOE requires tracking of equipment with a value of $5,000 or higher. The TSA project had roughly 20 pieces of equipment that required tracking. These items were tagged in the field and the identifying data was entered into a tracking sheet.

Lessons Learned

Communications Upgrade

IPC learned that when changing to a new frequency, the new frequency should not be near the existing frequency. If they are close, interference may occur when both frequencies are operating. This could occur while the existing frequency is still in-service and the new frequency is being tested.

Intermountain Tower performed well for both the structural and electrical requirements of the project. Employing one contractor that can perform all aspects of the project is beneficial for meeting project deadlines.

PMU Installation

Once the panel layout and wiring for a typical two SEL 587E installation was complete, the design time was considerably less for stations that followed.

The equipement tag process was successfully completed by including these steps:

1. The project communication engineer who ordered the equipment travelled to each site to identify the equipment.
2. A field operations employee decided where to place the tags to prevent the tag being placed bad location.

3. Digital pictures of the installed units were provided to IPC’s Accounting department to assure the task was complete. The photos also gave the Accounting deparment a sense of the work involved with the project as a whole.

IPC’s TSA project was successful for the following reasons:

1. The System Protection and Control Engineering groups quickly determined which synchrophasor equipment to used (PMU and PDC).
2. System Planning developed a prioritized list of locations to install the synchrophasors.
3. There were no changes in the design/engineering team throughout the project.
4. Subject matter experts (SME) were available to support the project.
5. Company management, includingthe vice presidents (VP), activily participatedon steering and technical advisory committees. Thus, management was aware of any project issues and was able to make prompt directional decisions.
6. The majority of the PMU station installations were completed by the same crew.

Budgets and Expenditures

Original PEP $1,337,769

Money spent $950,226

Revised PEP $1,337,416

Future of TSA Tool at IPC

The PMU data collected from the TSA tool will be used by IPC’s System Planning engineers and the Grid Operations department. System Planning engineers will use the data to analyze disturbances on the system and to validate their analytical models. Today, if a large-scale blackout event occurred it could take IPC’s engineers months to recreate what happened and determine the cause. Armed with the synchrophasor data, the System Planning engineers will be able to determine the cause of the outage in a few hours or less.

The Grid Operations department will use the synchrophasor data to build displays to allow system operators to monitor the stability of the system. These displays will enable the operator to detect low-frequency oscillations in the power system, monitor frequency stability, and monitor voltage stability of the system. Synchrophasors will also help IPC implement dynamic line ratings by providing ambient temperature and wind-speed data along transmission lines. They will also play a key role in IPC’s future system restoration plans. Synchrophasors will allow system operators to have a wide-area view of the transmission system and be more aware of the state of the system at any time. This will aid system operators to quickly act when electrical events occur.

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2013 SMART GRID REPORT

Appendix D-2

CONFIDENTIAL

User Manual for Developing a Methodology and Tool to Determine Probabilistic Available Transfer Capability

THIS APPENDIX IS CONFIDENTIAL AND WILL BE PROVIDED TO THOSE PARTIES THAT HAVE SIGNED THE PROTECTIVE AGREEMENT

IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix D-3

CONFIDENTIAL

Grid System Planning for Wind: Concurrent Cooling, Increasing Transmission Capacities with Dynamic Monitoring Systems

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Appendix D-4

CONFIDENTIAL
Idaho Power Company Geomagnetic Disturbance Study

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2013 SMART GRID REPORT

Appendix D-5

Advanced Metering Infrastructure (AMI)
"Phase II" Project Completion Report

Advanced Metering Infrastructure (AMI) “Phase II” Project Completion Report

December 2011

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BACKGROUND

Idaho Power conducted the first pilot of AMI technology in 1998, using the Two-Way Automated Communications System (TWACS) from Distribution Control Systems Inc. (DCSI). The pilot was comprised of a one substation bus section and 1,000 single-phase residential meters. Tests were conducted over the course of a year to confirm the ability to retrieve monthly meter readings, provide consistent communications on an extremely long distribution feeder through many line devices and to confirm the ability to reset displayed demand on commercial meters. At that time the Company was interested in the potential for deploying TWACS to reduce operating costs, eliminate estimated monthly reads and increasing reading accuracy in remote areas with seasonal impacts on our ability to read meters. It was concluded at the time that the technology functioned adequately but would not be cost effective.

Between 1998 and 2003 the company conducted several cost benefit analyses of TWACS. All the analyses concluded that the equipment was too expensive to install given the achievable related cost savings.

In 2000 and 2001 there was an “energy crisis” in the western energy market that drove market costs for energy to record highs. In light of this situation the Idaho Public Utilities Commission (IPUC) ordered Idaho Power in 2003 to analyze the potential benefits of implementing time of use (TOU) rates. The general conclusion was that traditional TOU rates based on fixed season and time of day would provide little benefit or protection against future price spikes. However, dynamic time variant rates triggered based on critical system or market conditions, could be effective in reducing peak system load. It was also concluded that implementing a large-scale dynamic time-of-use rate would require an AMI system capable of retrieving hourly energy consumption data from all energy revenue meters on the electrical system.

In early 2003 the IPUC ordered the Company to install AMI across all customer segments in 18 months. Idaho Power petitioned for reconsideration and after conducting workshops and numerous meetings with IPUC staff a consensus was reached to proceed with a “Phase I” deployment of AMI technology. The Company deployed TWACS to 7 substations and approximately 25,000 AMI meters to customers in the Emmett and McCall operating areas in 2004. The Company agreed to demonstrate the ability to gather hourly energy consumption data, provide timely and useful information to customers on their energy consumption and to pilot TOU rates based on hourly energy data. To facilitate the management of the AMI data, the Company purchased a Meter Data Management System from Itron, the Itron Enterprise Edition IEE. To provide customers with timely access to their energy use data, the Company purchased a Customer Care system from Nexus. The Company was required to update its cost benefit analysis of AMI and provide periodic reports on the “Phase I” deployment to the IPUC.

While the technology deployed in the pilot proved capable and dynamic TOU rates showed potential, the Company could not make a positive business case for deployment of AMI Company wide, the cost to deploy the technology was just too high at that time.

In 2007 there was a dramatic reduction in AMI technology costs driven by expanding markets for AMI, industry adoption of standards for interoperability of meters and AMI technology, and reduced engineering costs. As a result of these economic and technological changes, the Company was then able to model a positive business case.

While the long-term business case was positive for the Company, it became obvious that the cash flow impacts of an AMI project would need to be addressed before proceeding with a system wide deployment. In an effort to mitigate the cash flow issues, the Company filed an Application with the IPUC in 2008 requesting an Order granting the Company a Certificate of Public Convenience and Necessity (CPCN) to install AMI throughout its territory, granting authorization to accelerate the depreciation of the existing metering infrastructure, and including the corresponding operation and maintenance (O&M) benefits as they occur. IPUC Order Nos. 30726 and 30768 granted Idaho Power a CPCN for the implementation of a system wide AMI deployment over a three year period commencing in 2009.

Regulatory Actions

In October, 2008, Idaho Power filed a request with the Oregon Public Utility Commission (OPUC) to begin accelerating the depreciation of the existing meter equipment to be replaced by AMI in Oregon. The proposal requested recovery of the accelerated depreciation through a temporary rider that would increase customer rates while in effect. On December 30, 2008, the OPUC approved the Company's request, which allowed for the recovery of the investment in the existing metering equipment from January 1, 2009 through June 30, 2010.

On March 13, 2009, the Company filed a request with the IPUC for authority to increase the rates of affected customer classes due to the inclusion of the AMI investment in rate base. The request included the capital investments it made or would be making, the accelerated depreciation associated with the existing metering equipment, and an offset for the reduction in O&M expenses. The Commission approved the Company's request, using a 2009 test year, and increased the rates of the affected customer classes by $10.5 million on June 1, 2009.

Idaho Power filed a request with the IPUC to increase rates as a result of the AMI investment using a 2010 test year in March, 2010. The Company identified the AMI investment growing from $28,589,837 at year-end 2009 to $47,348,824 by December 31, 2010. The request was approved effective June 1, 2010, with an increase in revenues of $2.4 million.

In the spring of 2011, the Company evaluated the need for a filing to request an increase to customer rates due to the additional AMI investments made using a 2011 test year. It was determined that the operational efficiencies resulting from the deployment of AMI nearly offset the return on the new investments and a filing was not required.

Recovery of the Oregon jurisdictional share of the AMI investment was included in the Company's 2011 General Rate Case filing, Docket UE 233. The total capital investment included in the filing is estimated to be approximately $3.2 million. The Company has not yet received a final Order from the Commission regarding the outcome of its request.

Project Objectives

<u>Deploy a proven AMI technology</u>, that is applicable to as much of our service territory as practical, at a justifiable cost.

Technical requirements:

- Reading kilowatt-hour (kWh) and kilowatt (kW), and resetting peak monthly kW demand reads for all endpoints, for normal monthly billing.
- Reading kWh and kW for all endpoints on-demand, in support of customer movement reading.
- Providing two-way communications in support of demand reset confirmation and direct customer load control.
- Retrieving hourly energy consumption data from all endpoints in support of implementing dynamic, time-variant rates based on hourly consumption data.
- Providing valuable support in the outage management and outage restoration processes.

Budget Requirements

- Complete the project within 3 calendar years.
- End each calendar year at a point that could be managed if the project were delayed for some reason.
- Maintain an even capital budget over the 3 year deployment period.

Customer and Business Process Requirements

- Plan and execute the project in a manner that minimizes negative impacts on customers and the customer billing process.
- Provide customers and process owners with access to timely energy consumption data to educate them on energy use and support informed decision making.

Resource Requirements

- Minimize the impact of the project on internal Company resources by contracting with experienced professional service providers for as much of the actual AMI project work as practical.

Project Planning

Planning Responsibility

Executive management assigned a project sponsor, Duane Van Patten and a project manager, Mark Heintzelman. The project sponsor and project manager were tasked with documenting a project plan that included; detailed project scope, project management methodology, roles and responsibilities, project deliverables, resource requirements, communications plan, risk management plan, a detailed budget, and a deployment schedule.

Request for Proposal /Vender Selection Process

The project began by preparing for the request for proposal (RFP) process by identifying all of the physical meter types on our system, obtaining exact meter counts and aligning current meter/billing functional requirements with the future requirements of the AMI system.

The Company was already contracting with Denali Consulting on a strategic sourcing initiative so it leveraged the existing relationship to develop the RFP process for the AMI technology and installation contracting. The Company utilized the existing internal procurement and contracting resources, and established procedures and requirements throughout the planning, RFP and contracting processes.

The Company had installed 25,000 AMI meters and supporting communications infrastructure in 2004 and had the experience of operating that system for four years. The experience gained with the Phase I deployment benefited the Company when crafting many of the technology and professional services requirements for the RFPs and contracts.

Potential AMI product venders and installation contractors were identified through experience with the Automated Meter Reading Association (AMRA) (now Utilimetrics), the Edison Electric Institute (EEI) and input from project stakeholders.

The initial RFP process narrowed the AMI technology field to three potential technology providers and the installation contractor field was also narrowed to three service providers. Further discussions, demonstrations, functionality clarifications and experience quantifications facilitated the identification of a preferred technology provider and installation contractor.

Contracting and Procurement

The Company leveraged internal contracting and procurement resources and processes, and with Denali Consulting assisting, successfully negotiated favorable contracts for the procurement of materials and services required to implement an AMI system that would meet the functional requirements in the allotted timeframe.

Contracts for the project were awarded as follows:

The AMI Technology would be provided by Aclara. Idaho Power would deploy the Aclara TWACS AMI system across our entire service territory.

TWACS compatible commercial service meters would be purchased from General Electric, and residential service meters would be purchased from Landis & Gyr.

Meter exchange contractor service would be provided by TruCheck Utility Metering Services.

During the “Phase I” deployment The Company purchased and installed a Meter Data Management System MDMS from Itron, the Itron Enterprise Edition 4.0. The system was used to manage the data from the AMI system and calculate billing determinants from the hourly data provided from the AMI system to support TOU rate options. The contract for MDMS was later expanded to include the full deployment of AMI.

During the “Phase I” deployment the Company also purchased a Customer Care system from Nexus. That system provided the interface that allowed customers and Company personnel to access the data retrieved by the AMI system. The contract for the system was later expanded to include the full deployment of AMI. Nexus was subsequently purchased by Aclara, terms of the contract were not impacted by the acquisition.

Project Management/Staffing

The AMI Project was divided into three sub projects based on three distinct disciplines or skill sets. The sub-project categories included Meter Exchange, Substation/Backhaul Communications and Information Technology Systems. Each sub-project was assigned a project manager that reported to the AMI Project Manager. All three sub-projects were underway at the same time and inter-project coordination was essential to insure; the success of the project. This coordination emphasized the importance of recognizing sub-project interdependencies, mitigation of scheduling impacts as well as immediate mitigation of any inter-project issues.

Information Technology Systems

The information Systems required for AMI operation were already in place from the “Phase I” deployment in 2004 but required expansion and modification to accommodate a full deployment of AMI and expansion of system capabilities to meet the project requirements. The IT systems needed to be in place prior to the start of the AMI implementation and would need to stay in operation throughout the deployment. The IT Project Management group provided a project manager to support the AMI IT system implementation. Resources from Meter Support, IT and Customer Systems Support were assigned to the project as needed to accomplish the implementation and expansions of IT systems in support of the deployment.

Substation/Backhaul Communications

The substation construction and backhaul communication implementation was coordinated by a project manager. The PM coordinated the design, construction and implementation of all aspects of the back haul communications system, the schedule for station construction was imperative to the deployment of meters and project success was tied to completing the substation construction and backhaul communications implementation on schedule. The actual construction involved substation designers, numerous substation construction crews, communication engineers, and local substations, communications and metering personnel, and in many cases the local telephone service provider.

Meter Exchange

The meter exchange project was coordinated by a project manager; project staff included a metering system administrator and two meter system specialists. The support team was responsible for logistical coordination of; communications, material, meter exchange schedules and automated process implementation. The vast majority of meters (95%) were exchanged by TruCheck the meter exchange contractor. Complex or high voltage meters were exchanged by Idaho Power metering resources, these resources were also utilized to perform troubleshooting and mitigation of non communicating meters during deployment.

Budget Management and Record Keeping

The AMI Project Manager had the primary responsibility to develop the project budget and insure that the project stayed within the defined budget. The project was assigned a financial analyst to oversee the payment of invoices, assist in tracking and forecasting expenses, and administer or maintain proper record retention and financial procedure compliance.

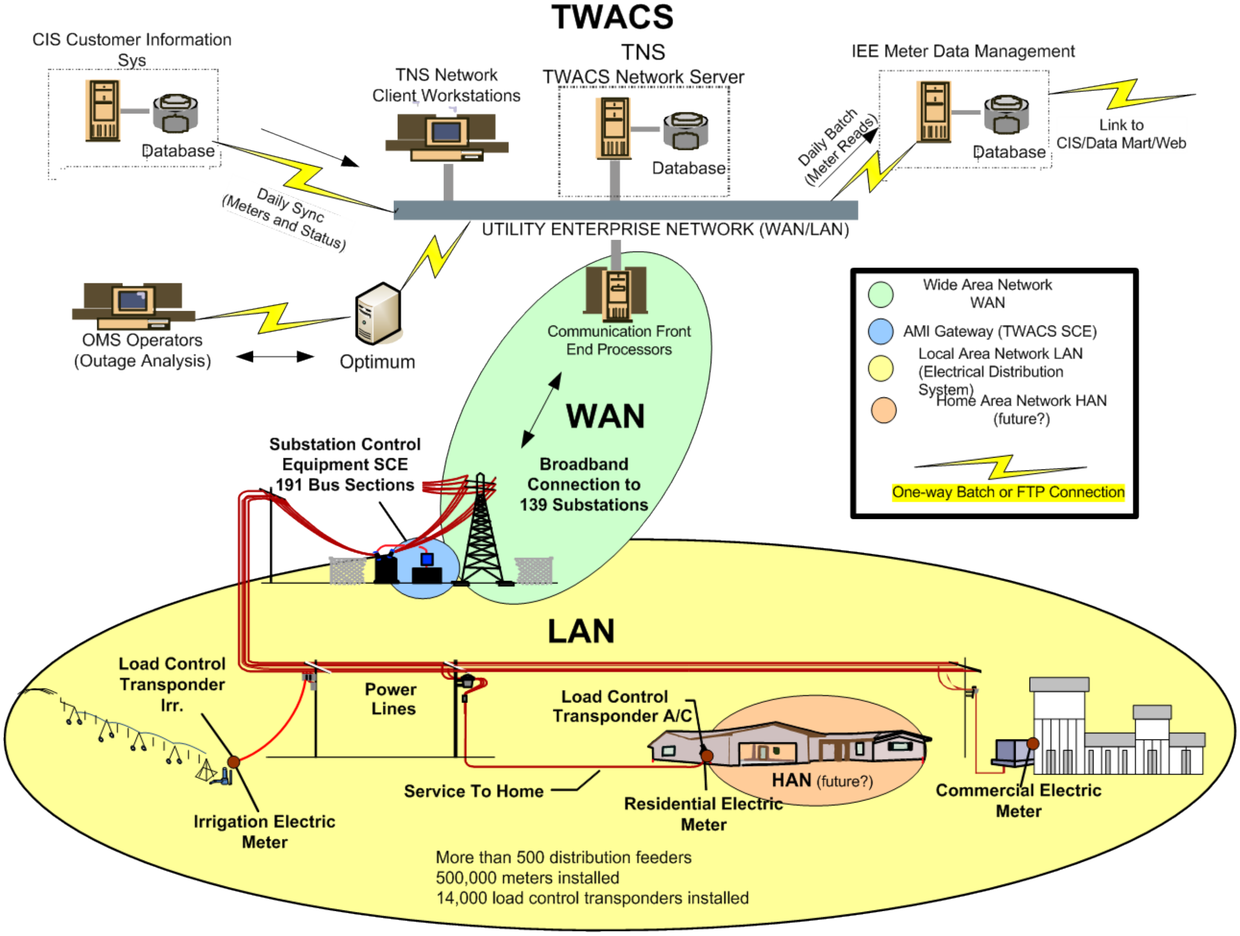
AMI Project Steering Council

A steering council was formed with representation from all areas of the Company impacted by or participating in the project. The council consisted of Senior Executives, managers, department leaders and department representatives. The council met monthly, to review the schedule, budget and any outstanding issues related to the project.

AMI Technology

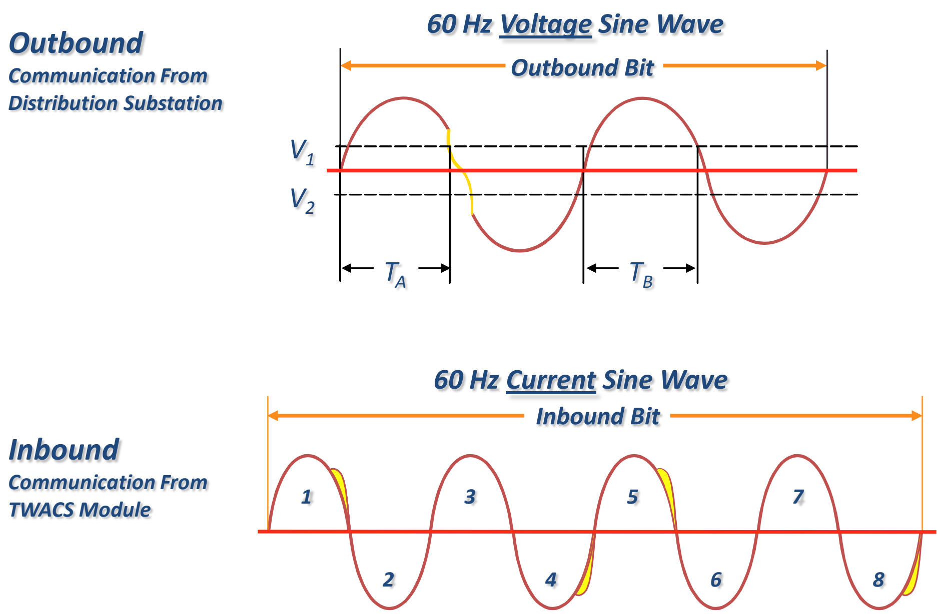
The AMI technology deployed was the Two Way Automated Communications System TWACS from Aclara. TWACS is a Power Line Communications PLC based technology. To deploy the system you connect broadband backhaul communications to a distribution substation where the TWACS Substation Control Equipment SCE is installed on each substation distribution bus section. Once the substation is equipped with SCE, communication endpoints can be added anywhere on that electrical distribution system. The Company installed TWACS transponder equipped new electric meters on all endpoints of TWACS equipped substations.

Idaho Power's – Aclara - Two Way Automated Communication System TWACS



Communications on the system is initiated from the TWACS Net Server TNS software on the Company's enterprise network. Commands are received at the substation where the SCE equipment passes the commands on through the electrical distribution system. Substation outbound communications are encrypted on the 60 Hz voltage sine wave and endpoint transponder inbound responses are encrypted on the 60 Hz current sine wave.

TWACS PLC **Communications**



Daily communication with all endpoints takes place in four sessions. The first session is scheduled for 10 minutes after midnight, when the system collects the register read for kWh and kW that the transponder placed in a memory buffer at midnight. There are then three communication sessions 8 hours apart over the next 24 hours; each session collects 8 hourly consumption readings, this schedule is repeated each day. The meter communication transponders have a memory buffer to store historic data that can be retrieved in the event the scheduled daily communications fail. Historic data retrieval is implemented as needed by manually scheduling a communications event targeting specific endpoints and specific data ranges.

The TWACS technology was not installed on 1% of our customers endpoints, the electrical distribution system did not have the economy of scale required to justify the expense of deployment of the communications backhaul or SCE.

(Appendix 1 Non-AMI meter counts and cost by distribution substation)

Project Outcome/Results

The objective was to "**<u>Deploy a proven AMI technology</u>, that is applicable to as much of our service territory as practical, at a justifiable cost."** The Company deployed the Aclara TWACS technology to 99% of our metered retail customers for an average endpoint cost of approximately $152.

Technology Deployment Results:

- Installed or upgraded broad band communications to 139 distribution substations and implemented 4 regional communications hubs.
- Installed the TWACS substation control equipment SCE on 191 distribution bus sections in 139 distribution substations across our service area.
- Installed 488,000 AMI meters.
- Installed the information technology systems to automate the processes for monthly bill calculation and customer movement bill calculation. Additional functionality to validate, warehouse and manage AMI meter data was added, enabling customers to view their hourly energy consumption data on our web site, supporting dynamic time-variant rate options and enhancing energy use analysis.

Technical Performance:

- The TWACS AMI system has proven consistent in reading kWh and kW, and resetting peak monthly kW demand reads for all endpoints, for normal monthly billing.

- The TWACS AMI system has proven consistent in reading kWh and kW for all endpoints on-demand, in support of customer movement reading.

- The TWACS AMI system provides two-way communications in support of demand reset confirmation and direct customer load control.

- The TWACS AMI system has been successful in retrieving hourly energy consumption data from all endpoints in support of implementing dynamic, time-variant rates based on hourly consumption data.

- Integration between TWACS and the Company's Outage Management System OMS has been delayed to allow for a planned replacement of the OMS system. When the new OMS system is installed, TWACS will provide valuable support in the outage management and outage restoration processes.

- The deployment of broadband communications to 139 of our distribution substations adds additional value by enabling new or improved secure communications for System Control and Data Acquisition SCADA. Installing additional SCADA controls or communications functionality was not part of the scope of the AMI project. However, communications backhaul was configured so expansion of functionality would be supported.

Financial Results:

Budget:

- The AMI Project was completed on schedule within the planned 3-year timeframe.
- The AMI Project was scheduled and completed in a manner that provided the Company the opportunity to manage the technology and processes had the project been delayed for any reason at the end of any year during the project. However this was not necessary, no delays were required.
- The budget and schedule were maintained throughout the project. The project was completed on schedule and within the allotted budget.

Budget vs. Actual (projected 11/30/11)

	Budget	Actual at completion
Metering	$57,285,907	$48,646,642
Stations	$15,526,399	$20,547,459
Software	$1,695,489	$4,030,730
Total	$74,507,795	$73,224,831

Business Case Model and Measureable Results

- Prior to beginning the project, the Company developed a long-term business case which compared an AMI installation scenario with a standard meter scenario resulting in savings of approximately $75 million. A summary of the results of the original business case analysis is provided below:

Original Business Case		AMI Total		Standard Total		Variance
PV of Investment in AMI	$	(89,927,397)	$	(13,576,862)	$	(76,350,535)
PV of Benefits	$	12,749,878				
PV of O&M Expense	$	(88,459,285)	$	(272,763,516)	$	184,304,231
PV of O&M Expense Net with Benefits	$	(75,709,407)			$	(75,709,407)
PV of Cash Tax Payments on Tax Deductible Expenses	$	63,772,892	$	109,779,320	$	(46,006,428)
PV of Total Cash Out Flow	$	(101,863,912)	$	(176,561,058)	$	74,697,146

- At the conclusion of Phase II, the Company updated its business case using actual cost data and confirming model assumptions. The snapshot taken using September 30, 2011 data, resulted in savings of approximately $54 million.

Updated Business Case						
		AMI Total		**Standard Total**		**Variance**
PV of Investment in AMI	$	(104,065,431)	$	(13,576,862)	$	(90,488,569)
PV of Benefits	$	13,345,928				
PV of O&M Expense	$	(101,361,831)	$	(272,763,516)	$	171,401,685
PV of O&M Expense Net with Benefits	$	(88,015,903)			$	(88,015,903)
PV of Cash Tax Payments on Tax Deductible Expenses	$	69,801,474	$	109,779,320	$	(39,977,846)
PV of Total Cash Out Flow	$	(122,279,859)	$	(176,561,058)	$	54,281,199

Operational Efficiencies:

- Quantifiable O&M benefits in 2011 result from the reduction in labor and transportation costs related to meter reading and the reduction in labor and transportation costs related to meter reads associated with customer movement and are estimated to be $7,399,105. These savings are expected to increase over time.
- With full AMI deployment and OMS integration in 2013, it is anticipated that additional O&M savings will be achieved.

Customer and Business Process Results

- The Company was successful in executing the project in a manner that minimized negative impacts on our customers and the customer billing process. The process gave a 20 day window to exchange meters and convert the route to automated reading. This facilitated converting routes from manual reading to automated reading in one bill period, virtually eliminating estimated readings from the conversion process. Focus was on completing routes and converting them to automated reading, new routes were not worked until routes in progress were 100% complete and converted.
- The AMI system has been successful in providing customers and process owners with access to timely energy consumption data to educate them on energy use and support informed decision making. Data for newly installed meters is available for viewing on the web once the first AMI billing is initiated. There is a delay of 32 hours for data presentment to allow for data validation and processing. By the time a customer receives a bill for energy use the data for the entire bill period is available for viewing on the web portal.
- For those areas where AMI is installed we are experiencing a 97% reduction in estimated billing reads. To put this in context, prior to AMI the Company estimated about 85,000 out of 6 million reads annually. Post AMI, estimated billing reads will fall to less than 3,000 annually. Post AMI estimations will result mainly from seasonal access issues for the 1% of meters not converted to AMI and a small number of failed AMI meters.

- Based on results in the areas where AMI is deployed, billing errors will be reduced by 98% post AMI deployment. The majority of billing errors prior to AMI were a direct result of errant meter readings or estimations. More accurate and frequent meter readings from AMI will eliminate on average 20,000 billing errors annually.
- Internal and external requests for billing rereads have dropped by 99% in areas where AMI has been deployed. Reflecting the confidence of customers and customer service personnel in the data received through AMI. Prior to deployment of AMI the Company would provide about 8,000 rereads annually, that number will fall to less than 100 post AMI deployment. The majority of rereads post AMI deployment are being performed on the 1% of meters not changed to AMI during the project.

Resource Impacts

- The AMI project was completed with minimal impacts on internal resources. The majority of the meter exchange work was performed by our contract resources. The fulltime project staffing was accomplished with IPC employees on temporary assignment to the project. The regular positions of the employees assigned to the project full time were backfilled during the project.
- A reduction in meter specialist positions from 2007 – 2012 was 74 positions across the property. The staffing reductions resulted in only 8 involuntary separations. The remaining reductions were achieved through attrition and job transfers within the Company.

Ongoing Manual Meter Reading Operations

- Approximately 4,800 or 1% of our total meters were not converted to AMI. The cost of deploying AMI backhaul communications and TWACS SCE in the substations that serve those customers was not justified by the achievable reduction in operation and maintenance costs. In fact, including those service points in the project would have a dramatic negative impact on the economics for the entire AMI project. The 4,800 customers are distributed in Idaho (3,250) and Oregon (1,550)
- In 2012 the Company plans to replace the mechanical meters in the non-AMI areas with solid-state meters that were removed as part of the AMI Project. This will result in the Company having solid state meters on all retail customer accounts.

Next Steps/Phase III

Ongoing Smart Grid Projects

The Company is currently engaged in a number of Smart Grid projects that require significant IT resources to support the implementation. Projects include the replacement of the current customer billing system, data warehouse replacement and implementation of a new outage management system. Any Phase III AMI implementation will be contingent on having no impact on any ongoing Smart Grid projects, therefore it is likely that any Phase III projects requiring IT resources or changes to IT systems will not occur until the Smart Grid projects are complete in 2013.

Re-Evaluation of Non-AMI Areas

AMI deployment did not take place in a small number of isolated remote areas where the cost benefits of AMI deployment did not meet the criteria for deployment. The impact was less than 1% of the Idaho customers and 10% of the Oregon customers did not receive AMI meters in the Phase II deployment. Over the course of 2012 the Company will track the cost of manual meter reading and customer movement reading in the non-AMI areas and apply that data to reevaluate the cost benefit of applying the TWACS technology to automate the processes in those areas. Other potential options to provide automated meter services will also be evaluated. It is unlikely that any additional AMI installations would occur prior to the completion of the Smart Grid projects in 2013.

Integration with the Outage Management System (OMS)

Integration between the AMI system and OMS was initially scheduled to begin in 2010 with the Capital Region and phase in other regions as the deployment of AMI progressed achieving full integration in 2012. However, the Company had a separate initiative to upgrade the current OMS system and the timing of the upgrade to OMS conflicted with the planned integration with AMI. The decision was made to integrate the systems in 2013 as part of the OMS replacement project. This eliminates the need to integrate with the existing OMS and immediately begin reworking the interfaces between the systems to facilitate integration with the new OMS. The current projection is to have OMS and AMI integrated in 2013.

Implementation of Scheduled Voltage Reading

The existing AMI system has the ability to retrieve service point voltage readings. In 2012 The Company will evaluate how and when to retrieve voltage data, and make that data available to the internal company personnel. Actual retrieval of voltage data would not likely be systematically implemented until the Smart Grid projects are complete. To adequately handle the volume of voltage data retrieved by the AMI system, data storage and accessibility issues will need to be addressed and that will require the functionality of Energy Data Warehouse EDW that will not be in service until 2013.

Interim (prior to EDW integration) voltage reading through AMI will be conducted on an as needed basis, based on engineering requests, limiting data retrieval and storage to volumes that can be reasonably exported from the AMI system on an ad hoc basis without significant impact to the AMI system or system operation resources.

Evaluation of Automated Residential Connect/Disconnect Collars

Idaho Power did not deploy remote disconnect devices during the initial deployment of AMI for several reasons. First, there is a very limited application for disconnect devices due to the small number of actual disconnects performed on residential customers and the rarity of occurrence of actual disconnects on the same service points. Also, the cost of disconnect devices was prohibitive to mass deployment without clear process applicability. The small number of service points that have had repeat occurrences of actual disconnection are typically associated with disconnects for nonpayment. Economical use of remote disconnects for non-payment would require significant changes to or a waiver of PUC rules related to notification of disconnection for nonpayment.

In 2012 Idaho Power will evaluate the feasibility of installing a limited number of automated disconnect devices and perform a cost benefit analysis. The Company will also review the PUC rules related to disconnection for nonpayment and determine how the rules would need to be changed or waived to allow the use of automated disconnect devices.

It is unlikely that deployment of automated disconnect devices could occur prior to the completion of the Smart Grid project to replace the current customer billing system. Implementation of automated disconnects through AMI would require significant process and notification changes, that will require changes to the customer billing system prior to the actual deployment of automated disconnect technology.

Load Control Transponders (LCT)

The backhaul communication system and software installed with the deployment of AMI supports the independent ongoing deployment and operation of LCT devices. Deployment of the devices and operation of devices related to direct customer load control is outside the scope of the AMI project. LCT devices will be budgeted and managed independent of the AMI project. Operation of LCT devices is not a significant burden on the AMI system and minimal coordination between functional areas will be all that is required to support program expansions. Current deployment of LCT devices stands at approximately 14,000 units in the field on residential air conditioners and a small number of units being piloted for irrigation load control.

Revenue Protection

The AMI system as deployed provides significant benefits in the area of revenue protection over manual meter reading processes. The system provides frequent readings, daily reading validations and a dramatic reduction in billing estimations and reading errors. In 2012 Idaho Power will evaluate the potential of the system to enhance revenue protection by implementing additional processes, functionality or systems.

Re-Evaluation of Additional Features

The AMI system has a number of features that can be purchased as add-ons. They include; distribution system capacitor control, prepay technology, in-home display and home area network. During initial evaluation of these features the Company found that each option required significant economies of scale to be cost effective. In all cases it was determined that there was not a significant need or desire for the features to justify the initial investment required to implement any of the add-on features.

Idaho Power will continue to monitor the need and desire for these additional features, if the situation changes in the future we will re-evaluate the implementation of additional features.

IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix D-6

Time of Day Pilot Study Status Report

Time Of Day

IDAHO POWER
An IDACORP Company

Pilot Study Status Report

June 20, 2013

Presentation Outline

- Historical perspective
- 2012 Time Of Day (TOD) pricing plan implementation
- Preliminary study results
- Preliminary revenue impact
- Next steps

Historical Perspective

- 2004 – Installed AMI Meters in Emmett and McCall areas
- 2005 – Pilots with Emmett area customers began and were in effect through 2011
  - Time-of-Day and Energy Watch options
  - Reports: IPC-E-05-02, IPC-E-06-05, IPC-E-07-05
- 2009 – 2011 Installation of AMI – whole service area
- 2012 – TOD Pilot Implementation Plan IPC-E-12-05
  - Energy Watch on the sideline for 2012
- Spring 2013 – Preliminary results on TOD Implementation Plan

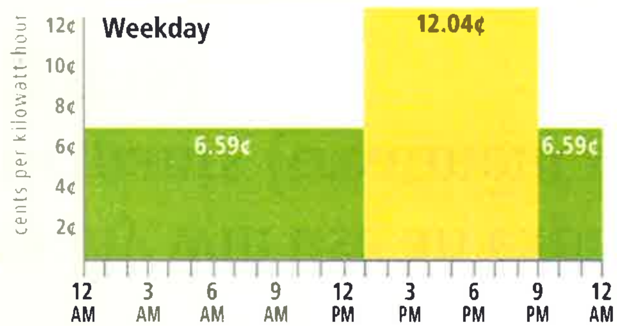
2012 TOD Plan Pilot Implementation Objectives

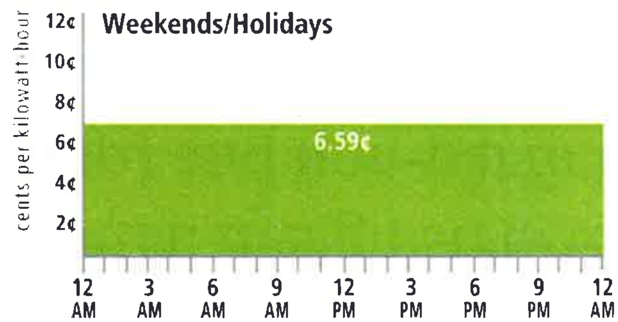
- **Utilize** smart meter – smart grid system
- Offer pricing **options** to customers and **opportunity** to reduce their bill
- Evaluate customer **response** rates
- Study changes in participant **behavior**
  - Target at least 1,200 participants
- Evaluate **revenue impact** of TOD pricing plan
- Learn and improve from customer experience

Pricing Plan Structure

Summer June - August (Pricing as of July 1, 2012)

Time Of Day Pricing Plan

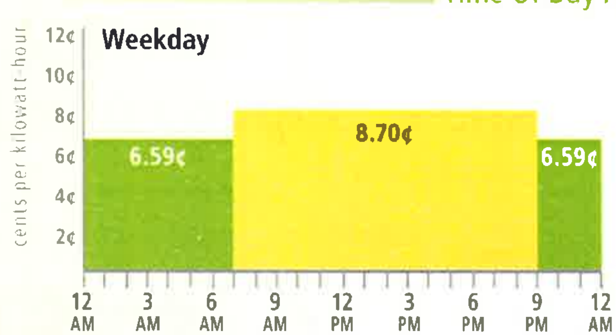


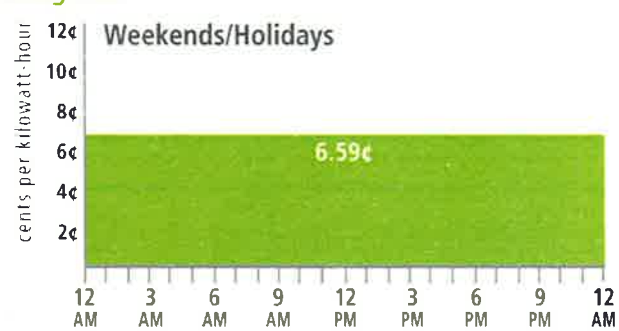


Peak: 1 p.m. to 9 p.m. weekdays, except holidays **Off-Peak:** 9 p.m. to 1 p.m. weekdays, Saturdays, Sundays and holidays

Non-Summer September - May (Pricing as of July 1, 2012)

Time Of Day Pricing Plan





Peak: 7 a.m. to 9 p.m. weekdays, except holidays **Off-Peak:** 9 p.m. to 7 a.m. weekdays, Saturdays, Sundays and holidays

Behavior Study Objectives

- The goal is to conduct a customer behavior study evaluating how the TOD pilot pricing plan impacted energy consumption for those who signed up during the 2012 plan implementation.

- The Company will use an experiential design structure with TOD participants (treatment group) and non-participants (control group).

Design Considerations

For selection of customers for study group and to solicit

- Start with Idaho residential customers – about 400,000
  - Take out customers identified as renters
  - Target customers with at least 12 months of AMI data – both for study purposes and to enable customers to compare plans.
    - Specific geographic area first to receive AMI meters
  - Take out customers with all monthly bills less than 800 kWh
  - Take out customers on "Do Not Call List"

  - *Above excluded from study not from pricing plan*

- This resulted in 132,077 customers in study frame

Study Design Considerations

Two-tier stratification approach

- Start with total residential customers (approximately 400,000 service points), limit residential rate class to the parameters, resulting in the study population of approximately 237,000 service points

- Separate the study population into four quadrants based on entire group's kWh usage. Each quadrant has equal number of customers

- Map the study frame service points (selected geographic area of the study- ~132,000 sps) onto the same breakpoints, assigning service points to quadrants

Two-Tier Stratification Design

Time Of Day

Study Population

Average Summer Bill (Jul/Aug/Sep)

0 kWh ↔ 1070 kWh ↔ max

50% of Custs	50% of Custs

Average Winter Bill (Dec/Jan/Feb)

25% of Custs	25% of Custs	25% of Custs	25% of Custs

0 kWh ↔ 955 kWh ↔ max | 0 kWh ↔ 1398 kWh ↔ max

Study Frame

Average Summer Bill (Jul/Aug/Sep)

0 kWh ↔ 1070 kWh ↔ max

41.6% of Custs	58.4% of Custs

Average Winter Bill (Dec/Jan/Feb)

26.2% of Custs	15.4% of Custs	34.3% of Custs	24.1% of Custs

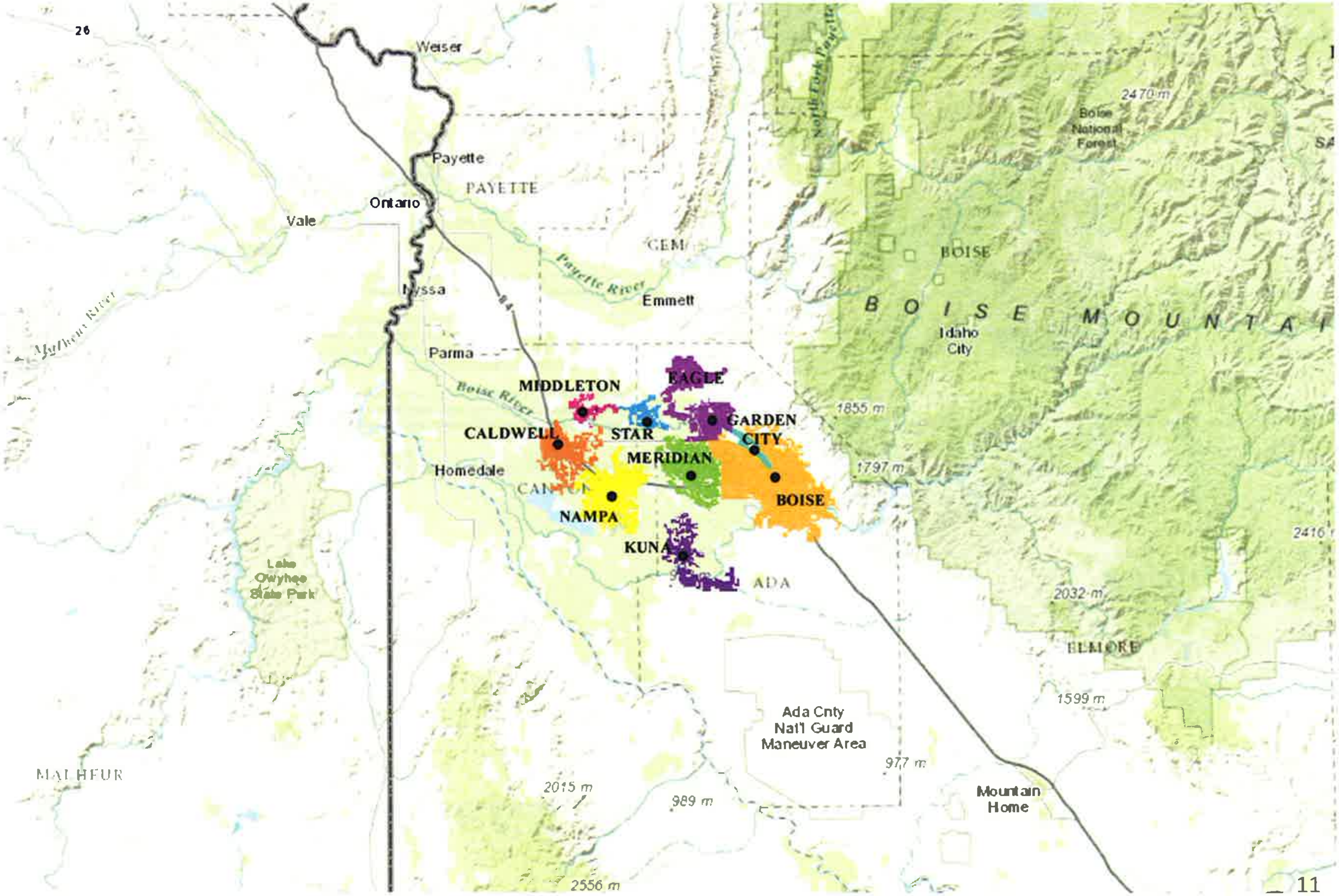
0 kWh ↔ 955 kWh ↔ max | 0 kWh ↔ 1398 kWh ↔ max

Solicitation of Participants

- Invited customers in random manner from study frame
- Marketing - one direct-mail invitation with letter and brochure
- Limitations on processing applications – 100 per week
  - Mailing solicitation letters in waves helped manage workload and monitor response
- Encouraged customers to visit website Plan Compare
  - www.idahopower.com/TOD
- Customers could respond by mail, website or phone
- First mailing April 27th, last mailing September 17th

TOD Study Area

Time Of Day



Marketing Collateral

Time Of Day

April 2, 2012

Joe Customer
1234 Main St.
Boise, Idaho 83706

Dear Joe,

You are invited to participate in a voluntary pilot for the Time Of Day pricing plan along with other randomly selected Idaho residential customers.

What you would pay under this pricing plan would depend upon the time of day you use electricity, encouraging you to shift your use to times when there is less demand on the electric system. A collective effort by our customers will result in a more efficient electric system.

Is the Time Of Day pricing option right for you? This plan may or may not result in an annual savings on your electric bill. It's important to first learn how and when you use electricity in your home. Review the enclosed brochure with helpful information about pricing for this plan, when Time Of Day hours occur and ideas on how to shift your energy use.

For more information and an estimate of what your annual electric bill might be on the Time Of Day plan versus the current plan, please visit www.idahopower.com/TOD. You also can:

- email TOD@idahopower.com with any questions, or
- call 208-388-5575 to speak with one of our customer service representatives.

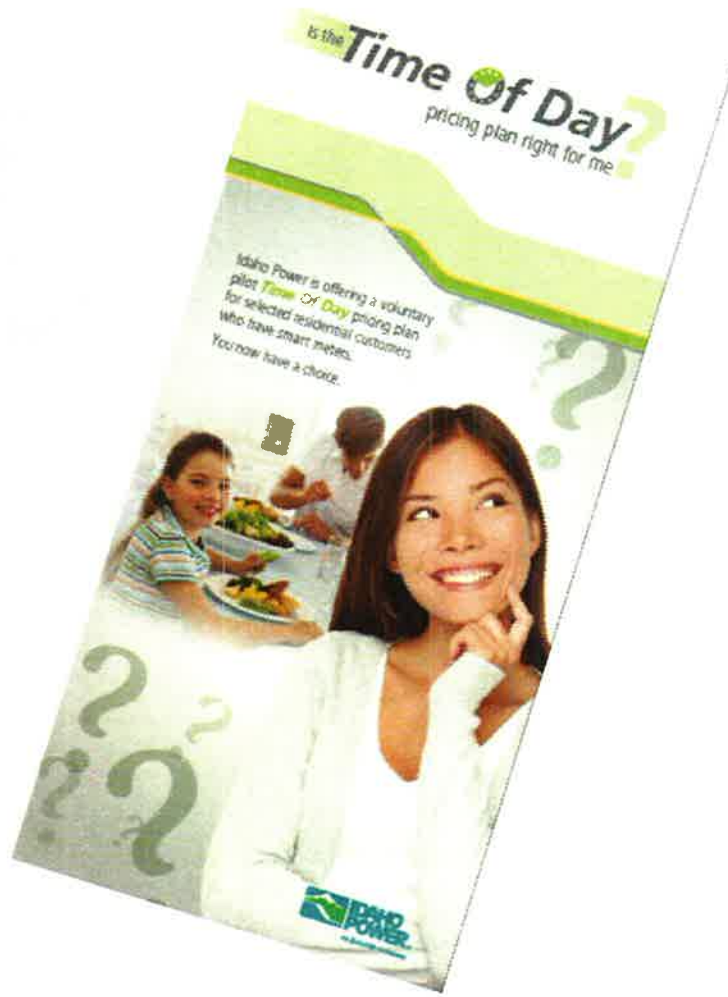
If you decide the Time Of Day pricing plan is right for you and want to participate in this pilot, please sign up online at www.idahopower.com/TOD or by returning the enclosed postage-paid postcard.

Thank you for considering this pricing plan opportunity. We appreciate your business and the opportunity to serve you.

Sincerely,

Warren Kline

Warren Kline
Vice President, Customer Operations
Idaho Power



Website Display

Home | Contact Us | Site Map

Time Of Day Plan

Print

Participating in the Time Of Day pricing plan may save money — and help reduce peak demand on the electrical system. This plan is available for customers who have Advanced Metering Infrastructure (AMI) meters.

- Compare Idaho Residential Plans In Account Manager

Or

- Sign Up For Time Of Day Now

This pricing plan provides some customers an opportunity to save a little on their electricity bill if they change the time of day and days of the week they use electricity. Without changing energy use, most customers' electricity bills will go up on the Time Of Day plan and some will not change. If you sign up for the plan but don't change your usage patterns, your electricity bill may go up.

It is important to identify how much energy you are currently using and when you are using it. If you are using less than 800 kWh per month, the Standard Residential plan may be your best option.

If you are using more than 800 kWh per month and can shift your usage, the Time Of Day plan may be your best option.

Time Of Day (weekdays only)	Summer Energy Time Periods	Rates*
1 p.m.–9 p.m.	Peak	12.04 cents per kWh
9 p.m.–1 p.m.	Off-Peak	6.59 cents per kWh

Time Of Day (weekdays only)	Non-Summer Energy Time Periods	Rates*
7 a.m.–9 p.m.	Peak	8.70 cents per kWh
9 p.m.–7 a.m.	Off-Peak	6.59 cents per kWh

Search

Related Information

- Time Of Day Plan Sign Up
- Time Of Day Plan FAQs
- Advanced Metering Infrastructure (AMI) Project

Compare Idaho Power Residential Plans

Log In Or Register Now

Time Of Day

Website Display

Plan Comparison Calculator

You can investigate the benefits of a new pricing plan and see the result of changed energy use habits. We will use your current bill and meter data to analyze your possible savings under various plans.

Current Plan:

Current Plan: Time-of-Day.

- Schedule I05 – Time Of Day
- Changing energy use patterns may help lower your monthly bill.
- Summer (June 1 – Aug 31) Peak hours occur Mon – Fri from 1 p.m. to 9 p.m.
- Summer Off-Peak hours occur for all other hours Mon – Fri, weekends, and holidays.
- Non-Summer (Sept 1 – May 31) Peak hours occur Mon – Fri from 7 a.m. to 9 p.m.
- Non-Summer Off-Peak hours occur for all other hours Mon – Fri, weekends, and holidays.
- Learn more about the Time Of Day Plan.

Compare Plans:

1. Choose a new plan to compare:

Standard Rate

- Schedule I01 – Residential Plan
- Reducing overall energy consumption will help you save on your monthly bill.
- Pricing changes occur in the tiered rate structure of 0-800 kWh, 801 to 2,000 kWh, and above 2,000 kWh.

2. Take action to save! Select your savings effort:

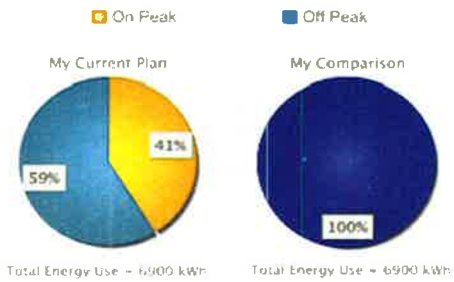
No Effort

No change

NOTICE: For some months, your energy pattern was *estimated* because *actual* hourly metered data was not available.

Display Annual Usage

Annual Usage Comparison



Your Estimated Annual Savings: $21

SIGN UP INFORMATION

To enroll, sign up for Time Of Day or contact Customer Service at 208-388-5575, 1-800-488-6151 outside the Treasure Valley.

Rollout Results

- **126,690** customer invitations sent as of mid-September
- Approximately **1,600** customers signed up for TOD plan
  - Includes previous Time-of-Day customers from Emmett
  - Includes non-study customers
- **1,436** customers are in the study analysis
- A little over **1.1%** response rate for study customers

Time Of Day

Treatment Group

Results of rollout

Quadrant (use description)	Customers	Response Rate
1 (Low Summer / Low Winter)	– 232 Customers	0.70%
2 (Low Summer / High Winter)	– 261 Customers	1.37%
3 (High Summer / Low Winter)	– 393 Customers	0.90%
4 (High Summer / High Winter)	– 550 Customers	1.81%

- 633 customers are AC Cool Credit customers, 803 are not

Rollout Results

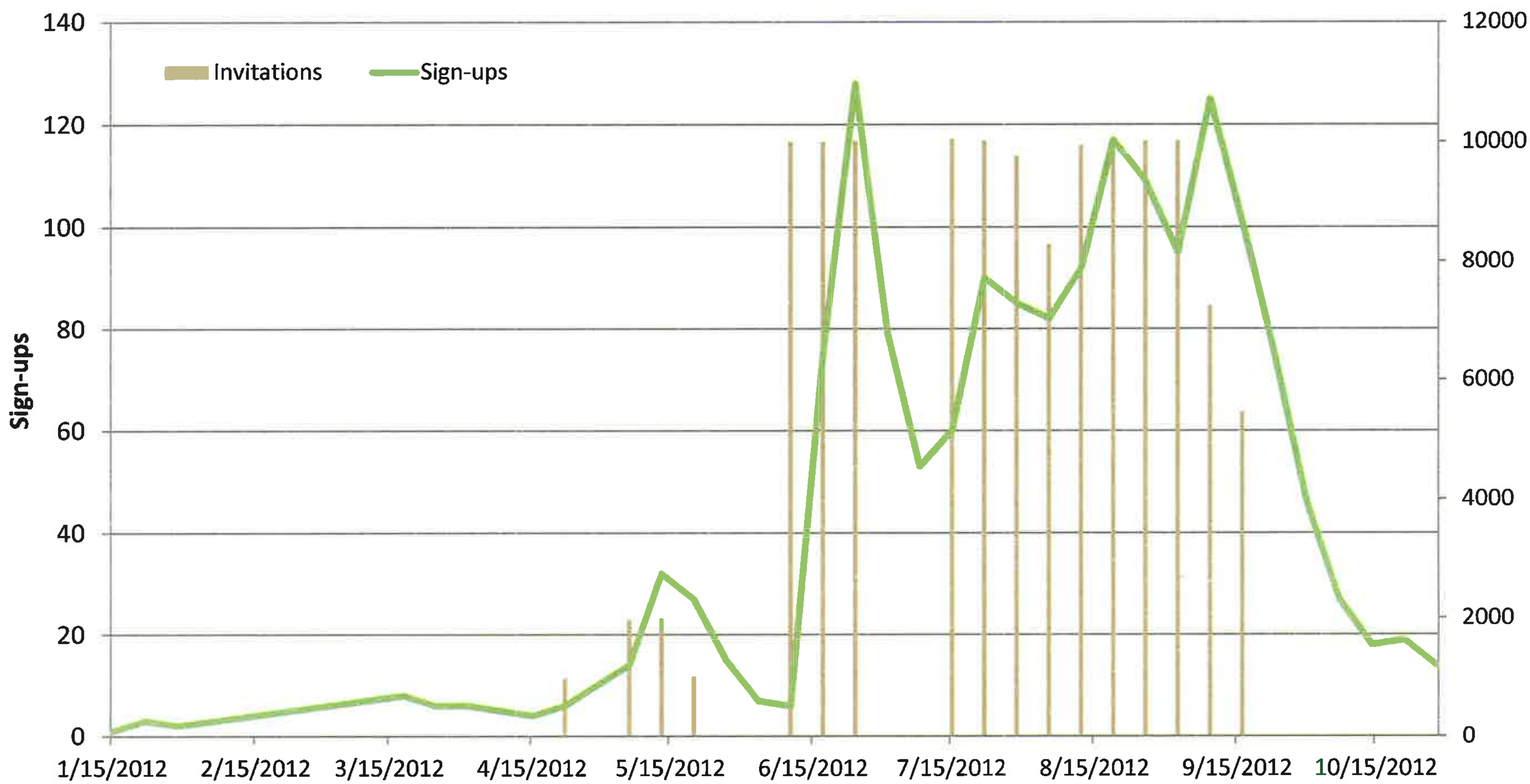
- Sign-up method:
  - 54% mail
  - 38% website
  - 8% phone

- Estimated Website use:
  - 49% of TOD customers used Account Manager (as compared to 30% of all customers)
  - Of TOD customers who used Account Manager, 52% used Plan Compare

2012 Time of Day Plan

Time Of Day

Weekly Invitations and Sign-ups



Time Of Day

Study Dates

High Level

- Pre-Study Period
  - April 1, 2011 to March 31, 2012
- Recruitment Period
  - April 1, 2012 – Sept. 30, 2012
- Initial Analysis Period
  - April 1, 2012 – Dec. 31, 2012 (sufficient data only July – Dec)
- Final Analysis will use at least 12 months usage of study group customers on TOD rate

Control Group Selection

The Pool

- Evaluating kWh usage before and after new rate shows changes but does not indicate if that change would have occurred anyway
- Control group indicates what changes are due to rate
- Controls for weather changes – does not weather normalize
- Closely matched control group
- Original Sample Frame -134,660 customers (SP)
- Removed anyone who was or had been on TOD pricing plan or anyone who had visited Plan Compare

Control Group Selection

Methodology

- Selected a control partner for each treatment participant to match as close as possible kWh usage pattern
- Potential Match Pairs based on:
  - 5-Digit Zip Code
  - Study Quadrant
  - AC Cycling Program Participation (Yes/No)
- Evaluate Seasonal Differences for each possible pair
- Match on demographics where possible

Time Of Day

Treatment and Control Groups

Demographics

Example: Distribution of Vintage and Size of Homes

Ada County	Treatment						Control					
Size	Quad1	Quad2	Quad3	Quad4	Total		Quad1	Quad2	Quad3	Quad4	Total	
<1400sf	38	26	26	20	110	**14%**	33	35	22	28	118	**15%**
1400-1799sf	39	19	48	23	129	**17%**	49	27	55	28	159	**20%**
1800-2399sf	48	31	78	57	214	**27%**	51	32	79	70	232	**29%**
2400-2999sf	25	11	60	61	157	**20%**	13	9	66	56	144	**18%**
3000-3999sf	8	16	37	57	118	**15%**	6	7	40	51	104	**13%**
4000+sf	1	3	8	41	53	**7%**		1	6	36	43	**5%**
Total	159	106	257	259	781		152	111	268	269	800	

Ada County	Treatment						Control					
Year Built	Quad1	Quad2	Quad3	Quad4	Total		Quad1	Quad2	Quad3	Quad4	Total	
<1960	30	28	26	31	115	**15%**	22	30	21	32	105	**13%**
1960-1969	11	5	13	12	41	**5%**	12	6	12	21	51	**6%**
1970-1979	22	25	31	69	147	**19%**	16	28	40	71	155	**19%**
1980-1989	8	15	29	25	77	**10%**	16	12	23	28	79	**10%**
1990-1999	42	22	76	57	197	**25%**	44	25	72	51	192	**24%**
2000+	46	11	82	66	204	**26%**	42	10	100	66	218	**27%**
Total	159	106	257	259	781		152	111	268	269	800	

Time Of Day

Treatment and Control Groups

Demographics

Example: CLARITAS Lifestage Groups and Other Tests

Claritas Category Lifestage Name	Treatment ServicePts	Trt %	Control ServicePts	Ctl %	Income	Age
MAINSTREAM FAMILIES	258	18%	274	19%	Med-Low	Family Life
CONSERVATIVE CLASSICS	204	14%	178	12%	Med-High	Mature Years
MIDLIFE SUCCESS	196	14%	186	13%	High	Younger Years
YOUNG ACCUMULATORS	168	12%	198	14%	Med-High	Family Life
CAUTIOUS COUPLES	142	10%	150	10%	Med-Low	Mature Years
ACCUMULATED WEALTH	115	8%	115	8%	High	Family Life
AFFLUENT EMPTY NESTS	87	6%	75	5%	High	Mature Years
YOUNG ACHIEVERS	73	5%	67	5%	Medium	Younger Years
SUSTAINING SENIORS	66	5%	66	5%	Low	Mature Years
STRIVING SINGLES	61	4%	59	4%	Low	Younger Years
SUSTAINING FAMILIES	43	3%	45	3%	Low	Family Life
N/A	23	2%	23	2%	n/a	n/a
Grand Total	1436		1436			

- Other Tests Conducted to Verify Good Control Matching
  - Density and In-town vs. Rural
  - Pool Ownership
  - Air Conditioning Saturation

Overall Change in Consumption

Preliminary Results

Month	Sum Wtd TRT - CTL kWh Difference	Wtd Confidence Interval (kWh)	Wtd Consumption Differences Significant?
Jul-12	-43.9	107.3	NSS
Aug-12	-22.3	84.8	NSS
Sep-12	17.2	54.5	NSS
Oct-12	-8.8	43.9	NSS
Nov-12	-11.5	59.1	NSS
Dec-12	-20.9	82.0	NSS

**NSS = Not Statistically Significant*

Average Treatment customer used slightly less energy in most months, but not at a statistically significant result level.

Time Of Day

Shift from Peak to Off Peak

Preliminary Results

Month	TRT Group Avg Wtd Off Pk kWh	TRT Group Avg Wtd On Pk kWh	Off Peak Wtd kWh Difference from CTL Group	On Peak Wtd kWh Difference from CTL Group	Off Pk Wtd Confi-dence Interval	On Peak Wtd Confi-dence Interval	OffPk Wtd Results Signifi-cant?	OnPk Wtd Results Signifi-cant?
Jul-12	1239	513	4.21	-48.10	79.00	32.72	NSS	Significant
Aug-12	1060	493	16.62	-38.87	60.95	26.90	NSS	Significant
Sep-12	702	415	28.62	-11.46	33.04	23.17	NSS	NSS
Oct-12	661	535	14.26	-23.02	25.57	20.24	NSS	Significant
Nov-12	818	596	5.32	-16.80	35.63	25.72	NSS	NSS
Dec-12	1126	717	-0.28	-20.57	51.76	32.50	NSS	NSS

In three of the six months, the overall average customer showed a statistically significant reduction of monthly energy during peak hours.

Preliminary Study Conclusions

- Still an interim analysis, more months for analysis with full rollout numbers should give more definitive results; final study results expected early 2014
- In general, no statistically significant decrease in overall consumption
- These preliminary results show some shift of kWh consumption away from peak hours

Time Of Day

Preliminary Revenue Impact

Comparison of TOD vs. Tiered Bills

	Schedule 5 TOD Bill		Schedule 1 Shadow Bill		Variance	
Revenue Month	Actual Qty (KWH)	Actual Amt	Pure Tiered Qty (KWH)	Pure Tiered Amt	Revenue Impact	Revenue Impact Pct
Apr,12	33,790	$2,397	33,790	$2,471	-$74	-2.98%
May,12	58,323	$4,119	58,323	$4,178	-$60	-1.43%
Jun,12	136,072	$9,719	136,072	$9,918	-$199	-2.00%
Jul,12	479,744	$37,365	479,744	$40,425	-$3,060	-7.57%
Aug,12	1,117,909	$92,564	1,117,909	$101,151	-$8,588	-8.49%
Sep,12	1,552,424	$125,512	1,552,425	$132,975	-$7,463	-5.61%
Oct,12	1,645,956	$123,465	1,645,956	$125,366	-$1,901	-1.52%
Nov,12	1,929,396	$144,110	1,929,396	$147,212	-$3,102	-2.11%
Dec,12	2,381,868	$176,928	2,381,868	$184,904	-$7,976	-4.31%
Jan,13	3,118,280	$231,478	3,118,280	$248,849	-$17,370	-6.98%
Feb,13	3,240,469	$242,167	3,240,469	$260,112	-$17,945	-6.90%
Mar,13	2,387,290	$178,390	2,387,290	$186,018	-$7,627	-4.10%
Apr,13	1,876,655	$140,192	1,876,655	$143,067	-$2,875	-2.01%
May,13	1,733,734	$129,634	1,733,734	$131,331	-$1,697	-1.29%
Grand Total	21,691,910	$1,638,040	21,691,911	$1,717,977	-$79,937	-4.65%

Preliminary Revenue Impact

By Study Quadrant

Comparison of Customers Bills by Quadrant
TOD Rates vs. Schedule 1 Rates
April 2012 – May 2013

Quadrant		Total Difference Energy Charge Bills	Customer Count	Average Customer Bill Difference
1	Low Summer/Low Winter	$2,637	220	$12
2	Low Summer/High Winter	-$8,164	242	-$34
3	High Summer/Low Winter	-$1,555	373	-$4
4	High Summer/High Winter	-$62,805	530	-$118
	Non-study participants	-$10,051	197	-$51
	Total Group	-$79,937	1,562	-$51

Next Steps

- 2013 no new solicitations planned, but tariff is available to new participants in Idaho service area
- Tariff advice to delete specific participation level
  - Original cap of 1,200 participants was set to obtain sufficient number for study and to manage new participant applicant processing
  - Propose to remove cap of 1,200 but include wording to reserve the ability to limit participation
- Continue study through 2013, customer survey planned
- Continue to inform electric vehicle customers about TOD option
- Study expected to be finished early 2014.

IDAHO POWER COMPANY

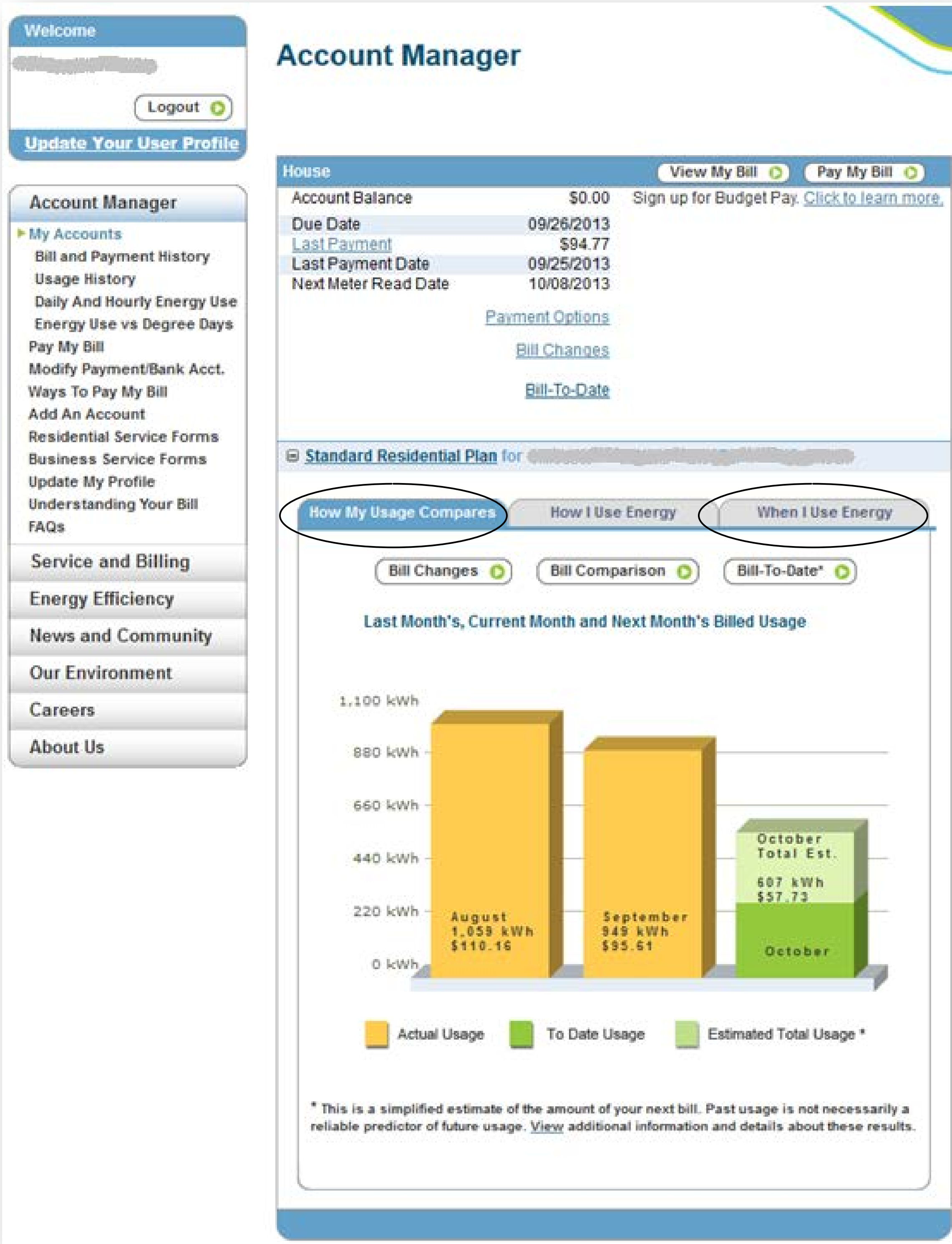
2013 SMART GRID REPORT

Appendix D-7

EUAT/Account Manager

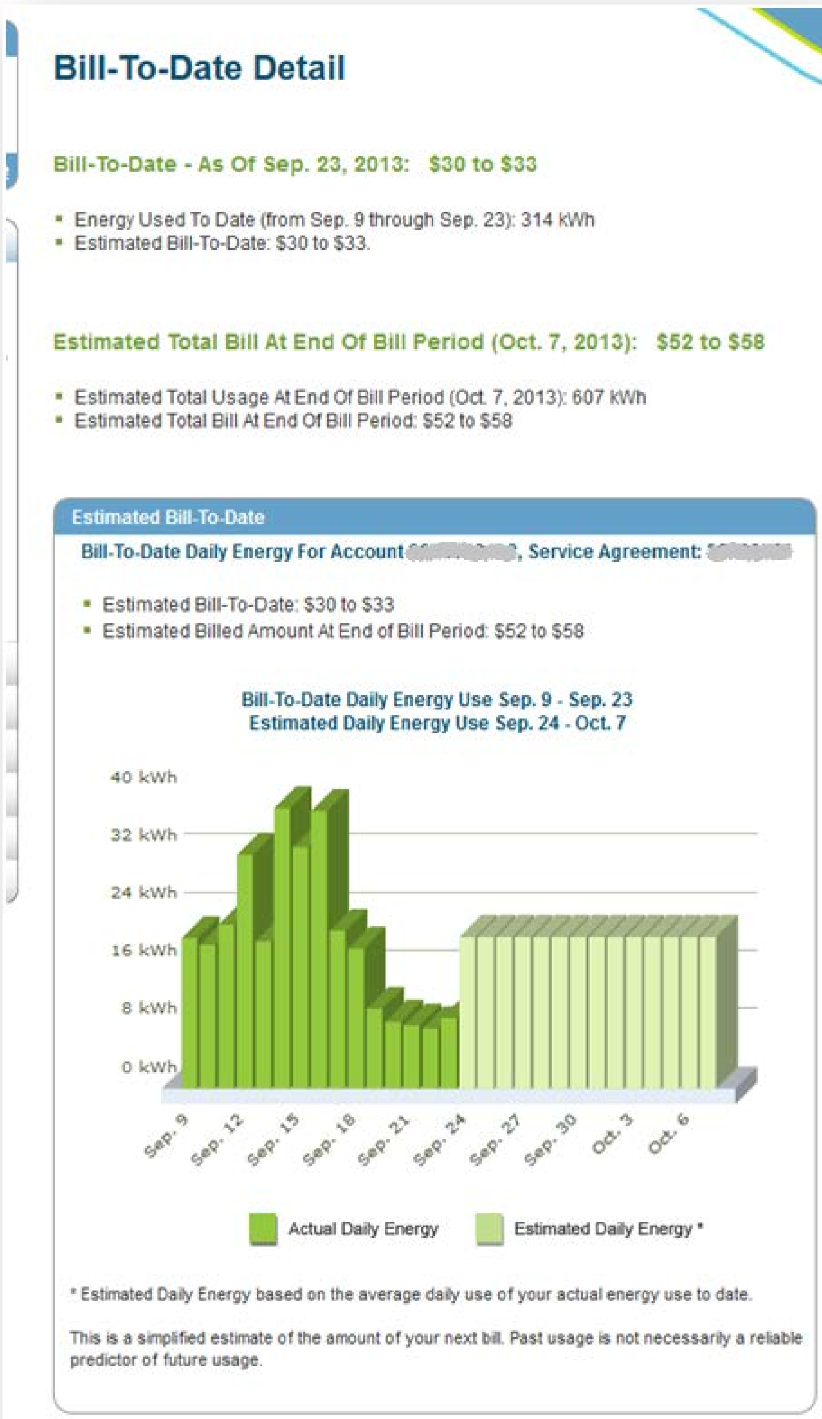
Residential Customer Account Manager with Smart Meter -

The Idaho Power website, www.idahopower.com, provides many features to enable residential customers to be empowered by becoming an Account Manager. Access to account information is available 24/7 so customers can do business when it is most convenient for them. Account Manager assists residential customers in understanding their usage and provides information, tools, and tips to save energy and money. The circled areas are tabs that contain detailed hourly data features only accessible to customer accounts with AMI data.



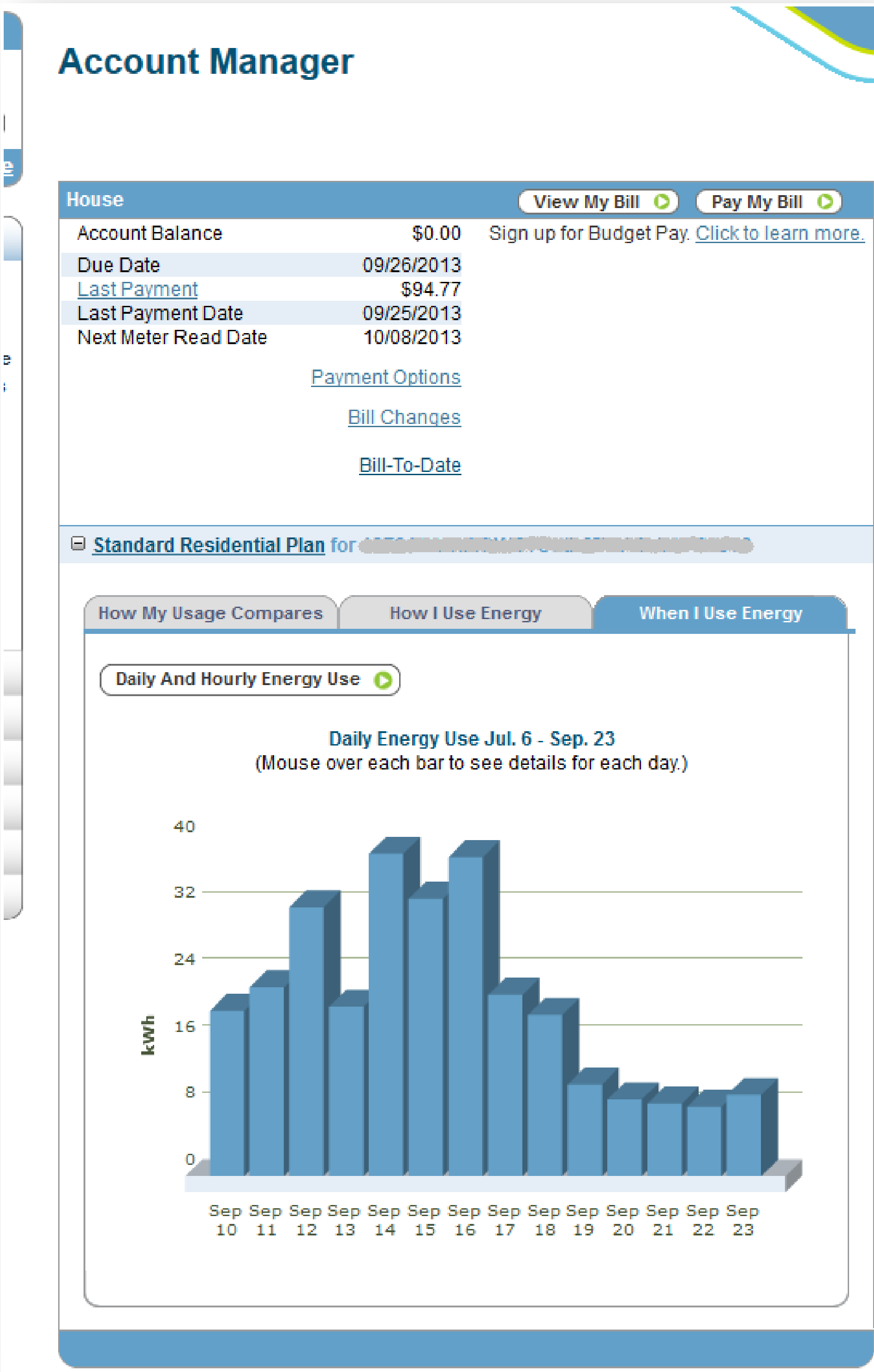
“How My Usage Compares” Tab

“Bill-To-Date” provides residential customers their current unbilled usage to date (three day lag) and provides an estimate of what their next month’s total usage and cost will be. Additional details are provided when the “Bill-To-Date” button is selected. This feature assists customers throughout the billing cycle by providing information to understand consumption and associated costs for optimal bill management.



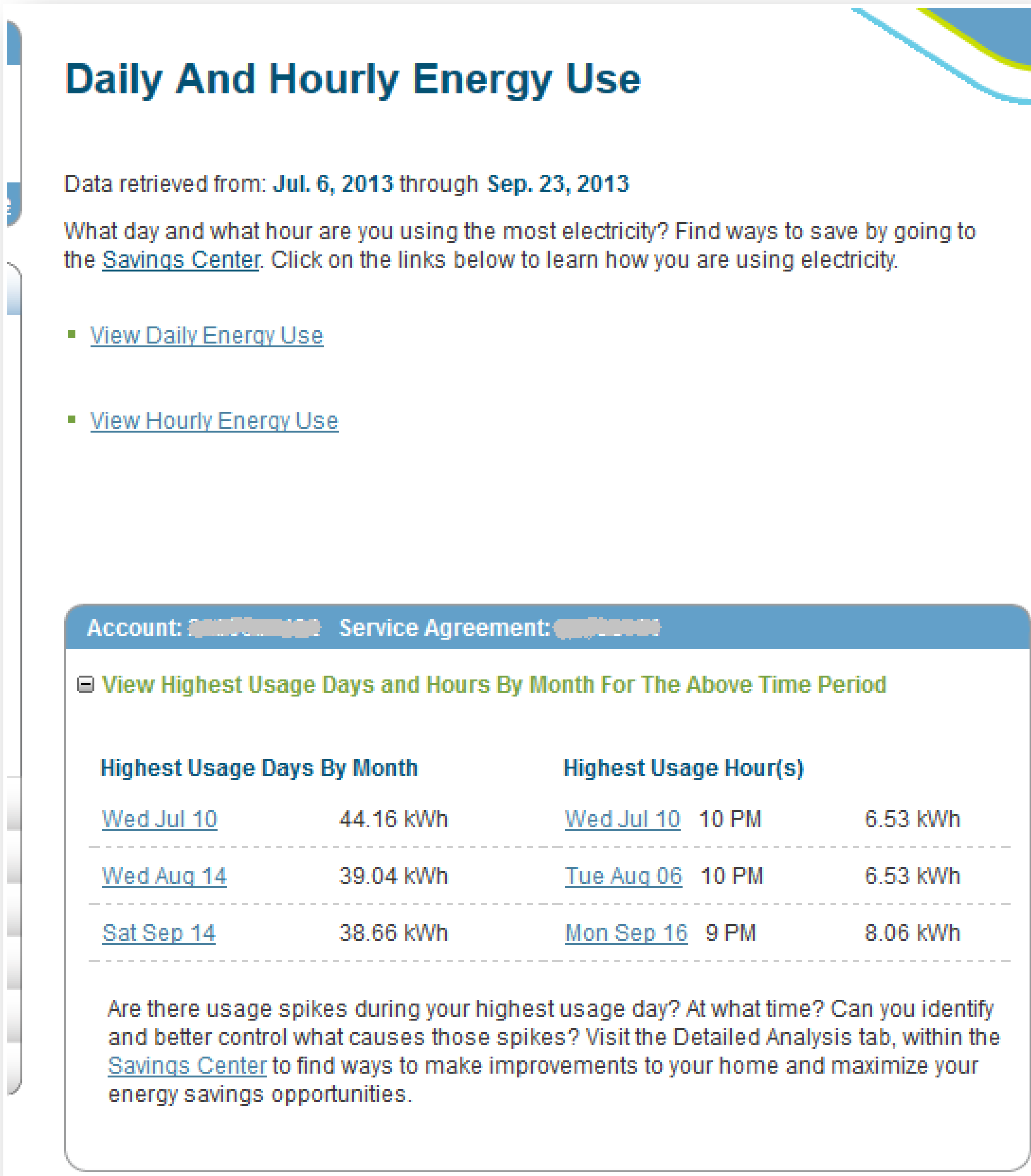
"When I Use Energy" Tab

Smart meter interval data -This bar chart shows residential customers their most recent 14 days of daily usage. By mousing over the bar chart, the usage amount of each representative day will display. If a customer desires additional interval meter data, he or she can select Daily And Hourly Energy Usage.

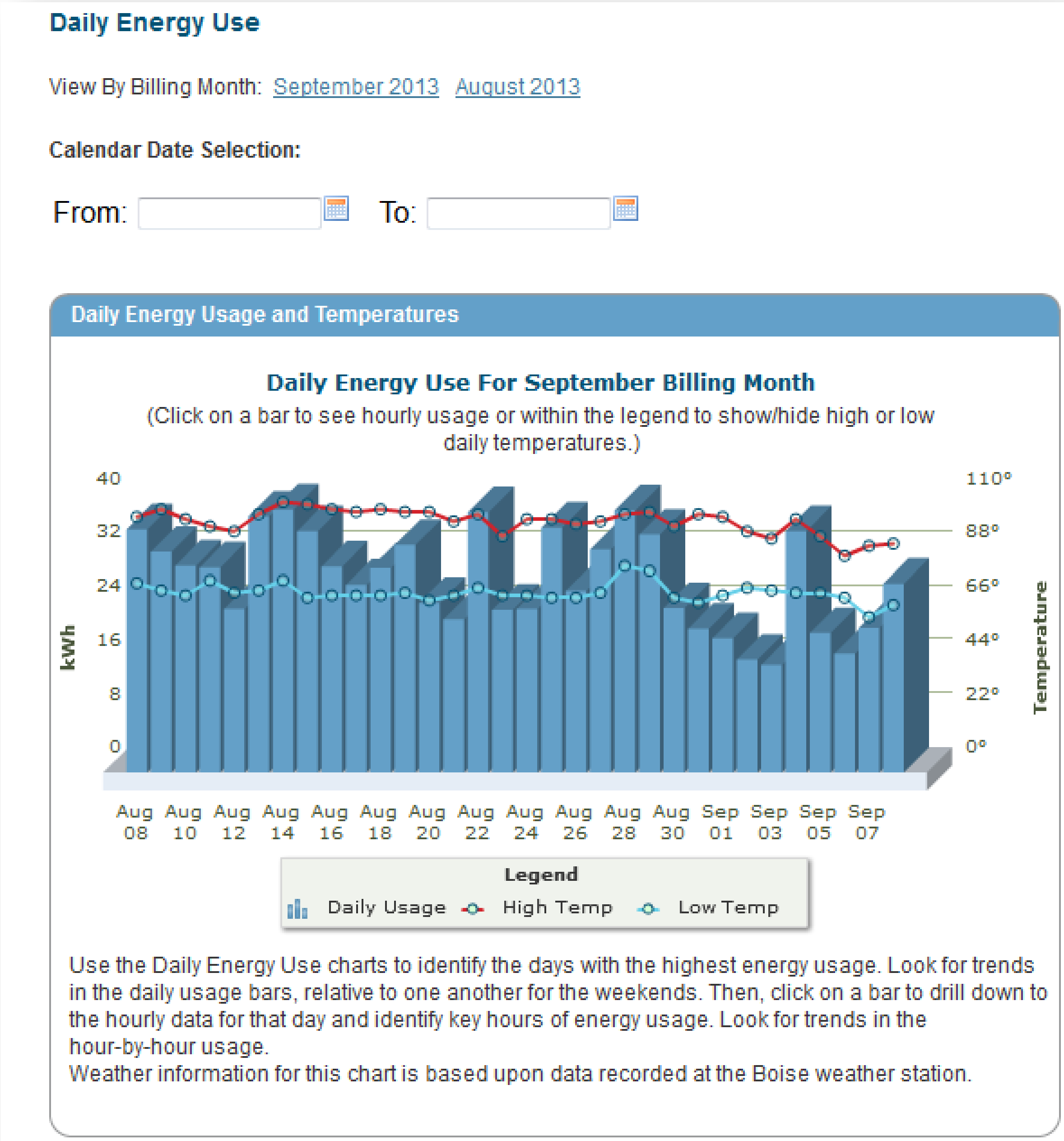


“When I Use Energy” Tab

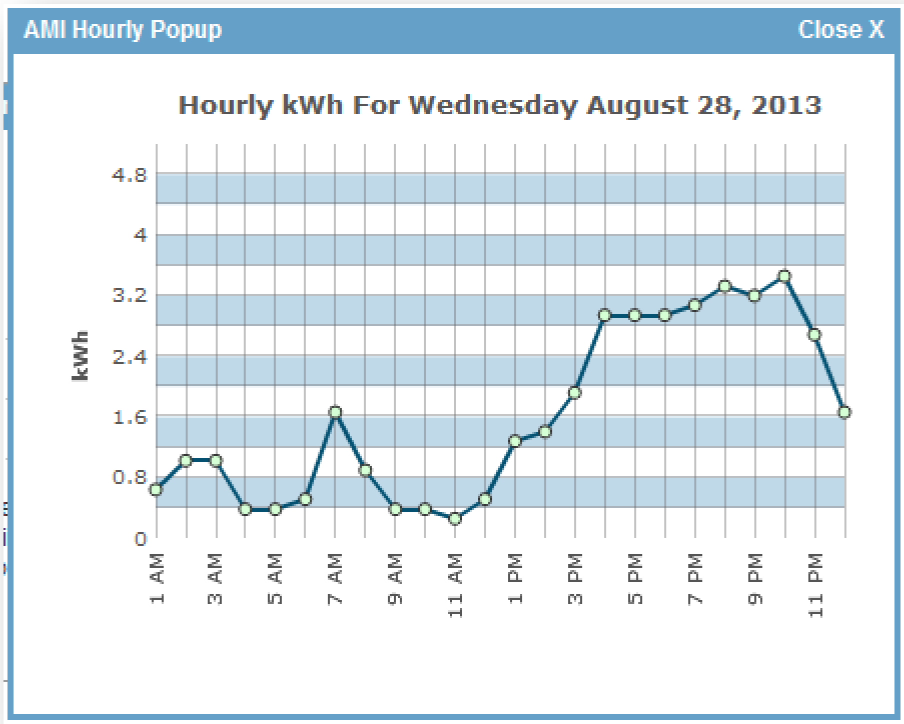
“**Daily And Hourly Energy Use” -** This function automatically identifies the highest usage days and highest usage hour(s) for recent months. This assists residential customers in understanding their usage behaviors and provides information opportunities to change those behaviors, supporting better-informed decisions about energy usage and its impacts. By selecting the View Daily Energy Use tab the customer is directed to the graph on the following page.



Customer with AMI account data can view daily usage information by billing month, calendar month or by selected date range. If a customer desires to view hourly information for a selected day, clicking the daily bar graph and selected day will present hourly information in the graph below. By mousing over the bar chart, the daily usage amount, High temperature and Low temperature of each representative day will display.



Customer accounts with AMI data can view hourly usage information for a specific day as shown in the Popup graph below.



Back To Top

The hourly kWh values indicate your "hour ending" energy use. For example, the energy value for the 2 p.m. hour, is the amount of energy used between 1 p.m. and 2 p.m.

As we implement our new system providing Daily and hourly energy use for your account, there may be gaps in your usage data due to minor system disruptions and maintenance. We apologize for any inconvenience this may cause you. Your monthly billing will continue to accurately reflect the total amount of electricity used.

If you have questions or require immediate assistance, call us at 208-388-2323, or 1-800-488-6151 from outside the Treasure Valley. Customer service representatives are available weekdays from 7:30 a.m. to 6:30 p.m., Mountain Time.

IDAHO POWER COMPANY

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Appendix D-8

Energy Use Advising Tool – Lessons Learned

Energy Use Advising Tool (EUAT)

Lessons Learned

June 2013

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ENERGY USE ADVISING TOOL—LESSONS LEARNED

Background

Original Scope

In August 2009, Idaho Power Company (IPC) applied for a Smart Grid Investment Grant (SGIG) that included the following project.

Energy Use Advising Tool (EUAT). The main component of the EUAT is Aclara's Energy Prism® application, which has two components. The first component is the Customer Bill Prism® tool that allows customers to access their detailed advanced metering infrastructure (AMI) usage information via the web. The second component, the Customer Service Representative (CSR) Bill Prism tool, provides CSRs the ability to access detailed AMI usage information for each customer. The Customer Bill Prism product provides customers with up-to-date energy usage information to support better-informed decisions about energy usage and its financial impacts.

Objectives

- Increase customer access to energy usage information
- Enable time-variant pricing (TVP) options via interval meter data
- Enable customers to access usage information gained via smart meters
- Allow customers to make informed choices regarding energy consumption

Revised Scope

The Contact Center Module (CCM)—a tool allowing CSRs to see information and graphics the customer sees on idahopower.com—was not purchased. Functional testing proved CSRs were not able to see exactly what the customer saw on idahopower.com. IPC implemented an alternate solution, built in-house, to allow CSRs to see exactly what a customer sees on idahopower.com. Also, an AMI presentment was added to allow additional rate plans to be presented; this allowed TVP plans to be presented graphically. The Rate Compare tool was purchased to allow customers to compare residential rate plans to make better-informed decisions about energy usage and its financial impacts.

Project Activities

Planning and Requirements

In accordance with IPC standard project methodology, the project team completed a formal planning and requirements processes.

Project Planning

Project planning included developing detailed scope statements, project-specific deliverables, a requirements definition, and a preliminary assessment of the organizational change activities required for the successful completion of the EUAT implementation.

Requirements Definition

Multiple specific deliverables from the requirements definition activities include the following:

- EUAT functional requirements—These requirements outline the functionality the system must provide the users.
- EUAT non-functional requirements—These requirements describe the quality characteristics of the system. Examples include performance, availability, security, and reliability.
- Use case development—The interactions between the system user and the system itself to perform a given business function.
- Integration requirements—A preliminary identification and mapping of other Information Technology (IT) systems within the IPC application portfolio that the EAUT interfaces with.

Lessons Learned

Successes

Design

- Thinking outside the box enabled the team to develop a creative solution to a difficult problem. Deciding to use cobrowsing, rather than the CSR tool, was a huge win for the project.
- Having subject-matter experts (SME) 100 percent dedicated to the project—especially web developers.

Project Planning

Assigning tasks in Outlook works well for task assignments.

Requirements

- A business lead who was also the primary contact with the vendor provided the team greater knowledge of the system and its capabilities, including how it works and functions currently.
- The meaningful reporting of financials to the Department of Energy (DOE) and to project sponsors helped measure the required elements for the DOE as well as report progress and status to the sponsors. To assist this process, a spreadsheet leveraged financial information

from Microsoft (MS) Project to report to the sponsors. This was extremely helpful and could serve as a template for future projects.

Testing

- Having specific times of day when changes are moved into the test environment worked well.
- Bringing in a contractor to assist with load testing was extremely successful.
- Having employees in the Customer Operations business unit (the business) involved in testing identified critical defects or recommendations and led to super users in critical departments.

Areas for Improvement

Project Planning

Understand the business and gather requirements before documentation begins.

Requirements

- Schedule time to complete knowledge transfer among the team.
- Address system limitation issues through an information technology request (ITR) rather than through the project. This would have reduced charges to the project and allowed the team to continue to focus on requirements and the vendor.
- Define the scope regarding the current system/future system and process to ensure everyone (team and sponsors) is on the same page, including a demonstration of the system and process with the sponsors to ensure everyone is in sync.
- Verify assumptions of sponsors regarding technical systems are cross checked with users of the system.

Testing

- Using new software (HP Quality Center [HPQC]) for the first time with very little prep time was difficult, as the testing started slowly. There was a learning curve for the entire team, including the test lead.
- Fast-tracking testing was difficult. It would have been preferred for all development complete prior to beginning testing.
- The testing time period outlined in the statement of work (SOW) was too small.

Budgets and Expenditures

Original Budgets (Budget Submitted in SGIG Proposal)

The amount budgeted in the original project execution plan (PEP) for the EUAT project was $487,585.

Revised Budgets with Explanations

The revised budget of $480,493 was submitted as part of the revised PEP in August 2011.

Money Spent

The actual amount spent on the EUAT project was $531,975.

IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix D-9

A/C Cool Credit Program Research Results

A/C Cool Credit Program

Research Results

Idaho Power Company | December 2012

Demand Response

peci

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Introduction

Background

Summer use of air conditioning (A/C) systems places a burden on Idaho Power Company's power supply, power contracts, and transmission and distribution departments. Demand reduction programs in which customers agree to curtail A/C use in times of demand stress have proven to successfully deliver significant and dispatchable demand (kW) savings.

Idaho Power's A/C Cool Credit program addresses this growing residential A/C demand. The program operated during the summer 2012 season, from June 1st through August 31st, offering a $7 credit on the approximately 38,000 participants' electric bills during those three months. The program's function was to curtail some residential Heating, Ventilating and Air Conditioning (HVAC) demand during the peak hours by implementing load reduction strategies which limited the time each HVAC unit operated within the specified curtailment period. A/C Cool Credit program curtailment events were limited to non-holiday weekdays and totaled 40 hours or less per month (with the exception of a system emergency). Idaho Power determined the desired cycling strategy implemented.

PECI conducted research with Idaho Power during the 2012 A/C Cool Credit (residential load control) curtailment season to identify optimal curtailment strategies to meet cost-effectiveness targets and develop a predictive model that correlates weather forecasts with achievable kW load shifts from curtailment events. For the 2012 summer curtailment season, Boise Metro and Twin Falls/Pocatello area participants were cycled at between 50% and 100%. The one curtailment event in each of the areas executed at 100%, at a temperature between 87 and 90 degrees, lasted for only one hour; The remaining A/C Cool Credit curtailment events during the 2012 curtailment season had durations of two or three hours. Most events began at 4:00 pm with durations of three hours. On three days, events were started at 5:00 pm, two events had durations of three hours, and one event lasted only two hours.

The goals of this research were to:

- Verify that savings can be estimated using AMI data.
- Verify the adaptive algorithm is working as designed.
- Estimate kW reductions at different temperatures and cycling strategies.
- Create a predictive model for planning purposes.
- Test the comfort impacts of higher cycling strategies to find the optimum curtailment strategy that maximizes kW results with minimum comfort impacts.

In order to obtain the necessary data to inform optimal strategies and develop a predictive model, PECI needed observations of different curtailment strategies (based on percent cycling) at different temperatures with corresponding baseline days where no curtailments occurred. The baseline days provided us with comparison information to ensure the impact on a curtailment day was fully attributed to the program. Overall, this curtailment research approach was a departure from previous years, where resources were called based on perceived system need and value. The key differences in implementing 2012 curtailments included:

- Events were called based on the predicted weather and which cycling levels needed to be tested. PECI requested different curtailment levels at the same temperatures so this will factor into the decision made on a given day.
- More curtailments were requested to ensure enough observations at various cycling levels – however not all requested curtailments were executed.
- Different target cycling levels were requested between Boise Metro and Twin Falls/Pocatello regions based on predicted high temperatures in each region however, execution of each event was conducted at the same cycling level.

Load Control Technology

Idaho Power currently utilizes four load control switches. Two of the devices operate with a power line carrier (PLC) signal and two operate utilizing a paging signal. The two PLC devices are manufactured by Aclara (formerly TWACS and DCSI). Idaho Power is phasing out the paging based devices due to changes in the paging provider marketplace. Therefore, the research focused only on the PLC devices.

Figure 1. Aclara Demand Response Unit (DRU)

Figure 2. Aclara Load Control Transponder (LCT)

Methodology

The demand reduction impact evaluation was conducted through the use of two primary data sources: state (ON/OFF) loggers installed on air-conditioning units of a random sample of the population, and AMI meter data for a census of program participants. To evaluate the impact of curtailments on occupant comfort, an analysis was conducted utilizing indoor air temperature loggers installed inside the homes of a subset of the homes that had received state (ON/OFF) data loggers.

Analysis of the three data sources was conducted using the SAS analytics program. SAS provides a robust platform for analyzing large amounts of data in a consistent manner. A unique SAS “model” was built to conduct the analysis of the three primary data sources. Each model was developed to first, import the relevant data from CSV files; second, process the data to configure it in a way suitable for analysis; and third, analyze the data to produce the desired result metrics.

The sub-sections below describe the methodology for the development of the sampling plan, recruitment of participants, analysis of the load reductions & indoor air temperature impact, and the predictive model.

Sampling plan

The sample plan was designed to enable research and analysis on the following:

1. Achieved kW at different temperatures and cycling strategies by climate zone (Twin Falls/Pocatello areas and the Boise Metro area) and provide the basis for a model for projecting kW demand reduction per cycling strategy and outside air temperature
2. Determine if adaptive algorithm embedded in the devices is operating as intended
3. Measure temperature drift in homes due to program curtailments in both climate zones.

The sampling plan for logger placement is based on the distribution of LCT and DRU units in both the Twin Falls/Pocatello and Boise Metro areas as of April 2012. The distribution is as follows:

Table 1. Control Device Distribution

	Boise Metro	*Twin Falls/ Pocatello*	*% Distribution*
LCT	5783	16	40%
DRU	4051	4779	60%
% Distribution	46%	54%	100%

Due to the very limited number of LCTs in the Twin Falls/Pocatello area (n=16), PECI determined more value could be obtained by concentrating the LCT sample in Boise Metro only. The purpose of testing both LCTs and DRUs is to evaluate the adaptive algorithm. Splitting the sample between populations does not provide additional value to the research project. By concentrating the LCT sample in Boise Metro only, other analysis can be completed at a higher confidence and precision.

Table 2. Design: Sample and Logger Distribution - Design

Actual distribution - Meets nearly 90/15 C.V. =0.7 or 80/20 c.v.=1.0

Switch Type	*Boise Metro*	*Twin Falls/Pocatello*	*Total*	*Precision*
LCT	58	--	58	90/15 for the LCT units
DRU	54	58	112	Meets better than 90/15 for DRU
Total	112	58	170	
Precision	Meets better than 90/15 in Boise Metro	90/15 for the TF/Pocatello area		

Table 2 describes the sampling plan that was put in place in April 2012. Due to a variety of reasons such as logger malfunction, misplacement, and removals, the actual number of loggers analyzed is 6.5% less than the original sampling plan.

Table 3. Sample and Logger Distribution - Actual

Switch Type	*Boise Metro*	*Twin Falls/Pocatello*	*Total*
LCT	53	--	53
DRU	49	57	106
Total	102	57	159

In addition, 78 Hobo temperature loggers were distributed between the Twin Falls/Pocatello and Boise Metro samples to measure rise in indoor air temperature during curtailment events. However, eight of the loggers were either lost by the home owners and were not recovered or the data was unusable. The final distribution of Hobo loggers is shown below.

Table 4. Hobo Logger Distribution - Actual

Switch Type	*Boise Metro*	*Twin Falls/Pocatello*	*Total*
LCT	5	--	5
DRU	34	31	65
Total	39	31	70

Participant Recruitment

PECI, with cooperation from Idaho Power staff, selected a random sample from the entire installed population of A/C Cool Credit program participants. Idaho Power sent a letter to these participants notifying them that they may be requested to be included in an evaluation of the A/C Cool Credit program. From this random sample, PECI called potential participants and asked if they were willing to participate. To protect the integrity of the sample, participants were not allowed to participate in the study unless they were called by PECI. Participants agreed to allow PECI to install a small data collection device on their A/C unit, along with a temperature sensor near the indoor thermostat. PECI successfully recruited all participants from the lists provided.

Adjusting Compressor kW for Outside Air Temperature

Outside air (OSA) temperature was also recorded at the same time as the compressor kW measurements. OSA temperature measurements were used to adjust the kW values to account for increases in the compressor kW demand during the hotter temperatures during curtailment events. The adjustment factor used to account for changes in compressor demand is based on a study that Paragon Consulting conducted on the relationship between OSA and compressor demand[1]. Paragon analyzed 130 AC units, recording demand data over a range of temperature values for each unit. This data was used to regress the relationship between compressor kW and OSA. The study found that for every degree increase in OSA, the compressor demand increased by 0.0164 kW. The kW of each compressor was calculated using the following equation:

$$kW_t = kW_i + 0.0164(T_t - T_i)$$

Where:
Tt = OSA temperature at time (t)
Ti = OSA temperature at the time of the onsite spot measurement
kWt is the kW of the compressor at time (t)
kWi is the kW of the compressor at the time of the onsite spot measurement

[1] Paragon Consulting (2006), “Residential Air Conditioning Load Management Program M&V Report: Nevada Power Company.”

Baseline Data

For the AMI and ON/OFF logger analysis, the load reduction achieved during load curtailments was calculated by comparing the average load from each curtailment day against the average load developed from non-curtailment days selected for the baseline. The “previous days” approach was used, which utilizes the average load data from the previous 10 non-weekend, non-curtailment days. Baseline kW was calculated as the average of the three days with the greatest demand from these previous ten non-curtailment days, as ranked by the highest hourly demand occurring during the curtailment timeframe. Curtailment days normally occur on hot, high demand days, thus selecting high demand days for the baseline ensures a similar load profile is used for the baseline days as the curtailment days.

The selection of baseline days for indoor air temperature analysis was conducted in a slightly different way. Singular baseline days were selected based on the closest average temperature during the curtailment event window.

Offset Factor

In order to effectively compare baseline and curtailment day loads, the baseline load was adjusted using an offset factor, calculated as the difference in kW between the baseline and curtailment event day load during the hour prior to the start of the curtailment. The offset factor was applied to the baseline day to “normalize” the baseline kW to the curtailment day kW. The offset factor mitigates underlying differences in load due to slight differences in outdoor temperature or other external factors. The same approach was used for the indoor air temperature analysis.

Predictive Model

The “IPC Curtailment Calculator” was developed with the aim of providing IPC with a tool for estimating demand reduction levels based on temperature and cycling percentage inputs. The calculator is Excel-based and driven by regression formulas developed in the SAS analytics program. The methodology for developing the regressions in SAS incorporated the following steps:

1. Using the “Average kW per unit” results from the AMI data analysis, the following variables were analyzed to determine the strength of correlation between the variable and the “Average kW per unit” result. Strength of correlation was defined by the variables’ “r-squared” value.
    a. Temperature at start of curtailment event
    b. Curtailment event day high temperature
    c. Percent cycling
    d. Previous day high temperature
    e. Previous night low temperature
    f. Length of event
    g. Start time
    h. All combinations of the variables listed above
2. A regression formula was developed for both regions (Boise Metro & Pocatello/Twin Falls) based on the independent variables of “Temperature at start of curtailment event,” “Percent cycling,” and the interactive effect of the two variables. While other independent variables did have higher r-squared values (e.g. start time), further data investigation indicated that the high correlation was due to chance and inclusion of the variables in the regression would not be a valid approach.
3. The Excel-based calculator was developed using the regression formula for each region. Users can input expected temperature at start of curtailment event and percent cycling, and the calculator will provide an estimated kW reduction per unit and total MW for the population of program participants. Alternatively, users can input temperature and a requested MW reduction amount, and the calculator will estimate the percent cycling required to achieve the requested MW reduction.

The Curtailment Calculator's regression formula is based on the "Average kW per unit" metric, and not "Max kW per unit." This is because the "Max kW per unit" metric does not produce statistically significant results in a regression based on the independent variables of "Temperature at start of curtailment event," "Percent cycling," and the interaction between the two. Whereas the regression based on "Average kW per unit" is statistically significant for those variables at the 95% confidence level for both regions' model, the regression based on "Max kW per unit" is not statistically significant for those variables. That is, when using "Max kW per unit" as the dependent variable, it is unclear whether the three independent variables analyzed impact estimated kW reduction in a positive or negative way. To enable Idaho Power to use the calculator to estimate max kW per unit for planning purposes, the relationship between the average and max kW was analyzed. The average variance between the two measured values was 11%, that is to say, on average, the max kW reduction was 11% larger than the average kW reduction. For the Curtailment Calculator, the average kW returned by the model is scaled up by 11% to estimate the max kW reduction for a planned event. This methodology is sufficient for planning purposes but should not replace post event evaluation.

Curtailment plan

A curtailment plan was provided to Idaho Power as a guide to gathering data for developing the predictive model. Weather and system operation were acknowledged variables that would impact the execution of curtailments.

Boise Metropolitan Area Curtailment Plan

The curtailment plan for the Boise Metropolitan area is shown in Table 1. It also shows the minimum number of events for each temperature and cycling strategy combination. PECI set a goal for a minimum number of baseline days where IPC did not curtail at a given temperature to compare to the event days. It was expected that IPC would likely exceed the number of baseline days targeted but a minimum number was specified to ensure these observations were captured in addition to the curtailment events.

Table 5. 2012 Curtailment Plan – Boise Metro Area

Cycling Percent	<90°	90-94°	95-99°	>100°	Total
100	1 (one hour)				1
80		2			2
75		1	3		4
70		3	3	1	7
65			3	1	4
60				2	2
55					0
50					0
Min Target Baseline Day (0%)		6	6	2	14
Max events called	1	6	9	4	20

As shown in Table 1, PECI asked IPC to execute one single event at 100% in the Boise Metro area. In order to reduce potential customer impacts, this event was called at a temperature between 87 and 90 degrees and for only one hour. On baseline days at the various target temperature ranges, IPC would intentionally avoid curtailments.

For the remaining events, the curtailment period followed the typical curtailment window of 3 hours between 4PM and 7PM. For each temperature bin, the requested curtailment events/levels were:

- **90 to 94 degrees:** Six (6) total events.
    - Two (2) events executed at 80% cycling;

– One (1) at 75% and
– Three (3) would be executed at 70% cycling.
– Six (6) baseline days were also requested.

- **95 to 99 degrees:** Nine (9) total events.
  – Three (3) events executed at 75% cycling,
  – Three (3) would be executed at 70% cycling, and
  – Three (3) at 65%.
  – Six (6) baseline days were also requested.

- **Greater than 100 degrees.** Four (4) total events.
  – One (1) event executed at 70% cycling;
  – One (1) at 75% and
  – Two (2) would be executed at 60% cycling.
  – Two (2) baseline days were also requested.

To ensure the total number of baseline and curtailment days at each temperature bin was realistic, PECI cross-checked the number with the average number of days reaching those high temperatures over the past five years. Table 2 summarizes the number of weekdays in each temperature bin for the Boise Metro area. The average number of weekdays where temperatures reach 100 degrees or more is five, unless it was a temperate year like 2011, in which there were no 100 degree weekdays.

Table 6. Frequency of Week Day High Temperatures from 2007-2011 – Boise Metro Area

Year	Less than 80°	80-89°	90-94°	95-99°	Greater than 100°
2007	6	17	10	24	9
2008	10	17	20	13	5
2009	16	16	15	14	5
2010	20	17	13	11	5
2011	17	16	15	18	0
Average	14	17	15	16	5

Twin Falls/Pocatello Area Curtailment Plan

The curtailment plan for the Twin Falls/Pocatello area is shown in Table 3. Table 3 shows the minimum number of events for each temperature and cycling strategy combination.

Table 7. 2012 Curtailment Plan –Twin Falls/Pocatello Metro Area

Cycling Percent	<90°	90-94°	95-99°	>100°	Total
100	1				1
80	1	5			6
75			2		2
70		5	2		7
65			2		2
60				1	1
55					0
50					0
Min Target Baseline Day (0%)	1	6	3	1	11
Max events called	2	10	6	1	19

As shown in Table 3, PECI asked IPC to execute one single event at 100% in the Twin Falls /Pocatello area. This event was to be called at a temperature between 87 and 90 degrees and for only one hour.

For the remaining events, the curtailment period followed the typical curtailment window of 3 hours between 4PM and 7PM. For each temperature bin, the required curtailment events/levels were:

- **90 to 94 degrees:** Ten (10) total events.
  - Five (5) events executed at 80% cycling, and
  - Five (5) executed at 70% cycling.
  - Six (6) baseline days were also requested.

- **95 to 99 degrees:** Six (6) total events.
  - Two (2) events executed at 75% cycling,
  - Two (2) executed at 70% cycling, and
  - Two (2) executed at 65% cycling.
  - Three (3) baseline days were also requested.

- **Greater than 100 degrees.** One (1) event at temperatures over 100 degrees.
  - This event would be executed at 60% cycling.
  - One (1) baseline day was also requested.

To ensure that the total number of baseline and curtailment days at each temperature bin was realistic for the Twin Falls/ Pocatello area, PECI cross-checked the number with the average number of days reaching those high temperatures over the past five years. Table 4 summarizes the number of weekdays in each temperature bin for the Twin Falls/Pocatello area. Twin Falls and Pocatello typically experience slightly cooler temperatures than Boise Metro. As such, we only included one event day and one baseline day when temperatures reach 100 degrees.

Table 8. Frequency of Week Day High Temperatures from 2007-2011 – Twin Falls/Pocatello Area

Year	Less than 80°	80-89°	90-94°	95-99°	Greater than 100°
2007	7	21	21	13	4
2008	11	25	20	8	1
2009	20	24	11	11	0
2010	22	18	18	6	2
2011	15	22	24	5	0
Average	15	22	19	9	1

To facilitate event tracking, PECI developed a checklist to track the curtailment combinations during the summer in the Boise Metro and Twin Falls/Pocatello areas, shown in Attachment A.

Data Collection

kW Measurements

The demand reduction analysis used a baseline day methodology, comparing the demand during the event day against the demand of similar baseline days. In order to collect demand reduction data, DENT Instrument's SMARTlogger™ series CTlogger™ were used to record the on/off state of the A/C compressor in each home selected for the Measurement and Verification (M&V) sample. The loggers continually monitored the signal of a split core current transformer (CT) clamped around the electrical supply wire to the A/C compressor unit. At the time of the logger installation, spot measurements of the demand (kW) of the A/C compressor were taken at unit start-up and after the unit had been operating for 10 minutes. Following the end of the curtailment season, the data loggers were retrieved and the A/C compressor run-time data was combined with measured A/C kW data to determine 5-minute average kW loads for each A/C unit. The compressor run-time data was converted to a percentage run time for 5-minute intervals. Multiplying the percentage run-time for each five minute interval by the kW value measured at the time of logger installation gave 5-minute average demand values for each compressor. These 5-minute average loads were used to determine kW load reduction during curtailment events as compared to baseline kW load.

Outdoor Temperature Data

Weather data, sourced from the National Oceanic and Atmospheric Administration (NOAA), for both the baseline and curtailment days was incorporated into the load profile charts of the Load Management Model. The temperature patterns on the curtailment event and baseline days provide an indication of the effect of ambient temperature on the load of the air conditioners, and in most cases, demonstrate a high level of similarity of temperatures between curtailment event and baseline days. This data is also incorporated into the regression models. For the Twin Falls/Pocatello area, the Pocatello temperatures were used. The NOAA data varied slightly from the target temperatures provided by Idaho Power. Since they are separate data sets, the slight differences are likely due to micro climate variations where the data was collected.

Indoor Air Temperature Measurements

In order to analyze the effects of curtailment events on indoor air temperature in participating homes, indoor air temperature during curtailment days was compared to the indoor air temperature in homes during a selected baseline day. Singular baseline days for the indoor air temperature analysis were selected by taking the day with the closest average outdoor air temperature to the curtailment event day during the curtailment event window. The baseline day was selected from the 10 previous non-weekend, non-curtailment days. Indoor air temperature data was collected using the U-series HOBO loggers. A total of 78 HOBO loggers were installed in sample participants' home near the indoor thermostat. The HOBO loggers recorded the indoor temperature in 5-minute intervals throughout the summer curtailment season.

AMI Meter Data

Idaho Power also provided the hourly AMI meter data for the census of A/C Cool Credit participants for the curtailment months for analysis.

Results

Curtailment Events

Using the curtailment plan developed by PECI, Idaho Power executed curtailment events. In some cases deviations from the plan were necessary. On July 11th and 12th, Idaho Power was expecting high system loads. System Operators staggered the start times of the A/C Cool Credit participants. One group was curtailed for three hours beginning at 4:00pm and the second was curtailed for three hours beginning at 5:00pm. In addition, the curtailment plan did not include curtailments at 50% but concerns for customer comfort motivated program staff to request events at this level to be included in the research. Table 9 below details the curtailments executed for the 2012 season.

Table 9. 2012 Executed Control Events

Date	Boise Metro Temp (hi)	TF/Pocatello Temp (hi)	Control Event Start Time	Control Event End Time	Cycling Percent	Length (hrs.)	Event Notes
6/21/2012	95	89	16:00	19:00	65%	3	
7/2/2012	95	89	17:00	18:00	100%	1	Only partial event
7/11/2012	99	94	16:00	20:00	60%	4*	2 Staggered groups
7/12/2012	106	99	16:00	20:00	60%	4*	2 Staggered groups
7/19/2012	104	95	16:00	19:00	65%	3	
7/25/2012	97	90	16:00	19:00	50%	3	
7/31/2012	97	94	17:00	19:00	70%	2	Two hour event
8/13/2012	97	93	16:00	19:00	50%	3	
8/16/2012	93	92	16:00	19:00	75%	3	
8/20/2012	94	86	16:00	19:00	65%	3	
8/22/2012	90	89	17:00	18:00	100%	1	One hour event

* Note: Individual customers were curtailed for three hours. The event from the system view lasted four hours

Table 10. 2012 Executed Control Events - Boise Metro Area

Cycling Percent	<90°	90-94°	95-99°	>99°	Total
100		22-Aug	2-Jul		2
80					0
75		16-Aug			1
70			31-Jul		1
65		20-Aug	21-Jun	19-Jul	3
60			11-Jul	12-Jul	2
55					0
50			25-Jul, 13-Aug		2
Total events called	0	3	6	2	11

Table 11. 2012 Executed Control Events – Twin Falls /Pocatello Area

Cycling Percent	<90°	90-94°	95-99°	>99°	Total
100	2-Jun, 22-Aug				2
80					0
75		16-Aug			1
70		31-Jul			1
65	21-Jun, 20-Aug		19-Jul		3
60		11-Jul	12-Jul		2
55					0
50		25-Jul, 13-Aug			2
Total events called	4	5	2	0	11

Demand Reduction Analysis Results

Verification of AMI Data for Estimating Results

One of the goals of the research was to verify AMI data for estimating demand reduction from curtailment events. There are several benefits to using AMI data.

- Data from virtually all program participants can be utilized in estimating the demand reduction.
- By taking a census of the participants, sampling error is no longer a consideration.
- The data is available immediately after events making verification of results possible within days of the event as opposed to waiting until after the curtailment season to retrieve loggers from the field.

Logger Data vs. AMI Data

This research evaluates data from two different sources: data from loggers that were installed at a sample of participant's homes, and AMI meter data that is automatically collected from a census of participants in the study. The main differences between these sources are as follows:

- *Sample size:* Loggers are installed on a sample of the population of participants, introducing sampling error, where the AMI meter data represents a census of the population.
- *Load measurement:* Loggers measure A/C unit power, while AMI data represents the full home's power load. Both of these measurements can be used to estimate kW reduction that results from a curtailment event. AMI data however, also captures any behavioral impacts resulting from curtailments. For example, some homeowners may realize they are in a curtailment event and reduce usage further or they may turn on fans or portable air conditioning units.
- *Cost of installation:* Loggers must be placed and removed each season they are used. There are costs associated with the technical expertise for properly installing and removing the loggers as well as rental costs for the loggers themselves. The AMI meters are already installed and used for billing purposes.
- *Data upload:* Loggers must be individually connected to a computer and data must be uploaded one home at a time. It is easier to access AMI data.

Even though the AMI meters and loggers measure slightly different parameters, these sources produce similar estimations of energy reduction per curtailment event. This is illustrated in Figure 4 and Figure 3. In these figures, the blue bars represent the kW reduction that is calculated using AMI data, while the red points represent the kW reduction that is calculated using logger data. Since the logger data is gathered from a sample of the population, there is a sampling precision associated with this data. The black bars represent this sampling precision, which is

±15% for the logger data. It is important to note that since AMI meters and loggers measure slightly different parameters (one is whole house energy and the other is just the AC unit), the kW reduction is not expected to be exactly the same using both datasets. This means that the precision bars are not expected to overlap with the AMI data in all cases. However, these figures do illustrate the fact that calculating kW reduction using AMI or logger data provides results that are approximate, further confirming the reliability of the AMI data.

It is clear that AMI data is reliable, cost effective, and produces more immediate feedback than gathering data through loggers. PECI recommends using only AMI data for all subsequent analyses of this Demand Response program.

Figure 3. Maximum kW Reduction per Curtailment Event

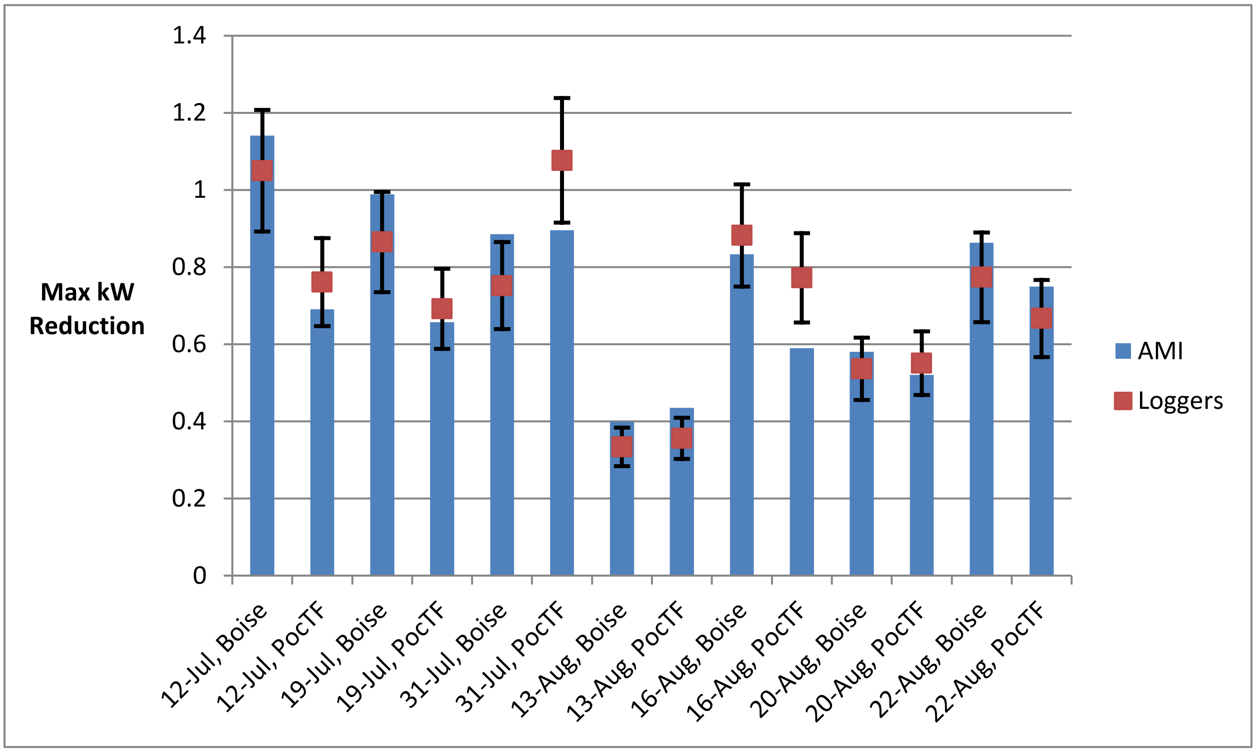
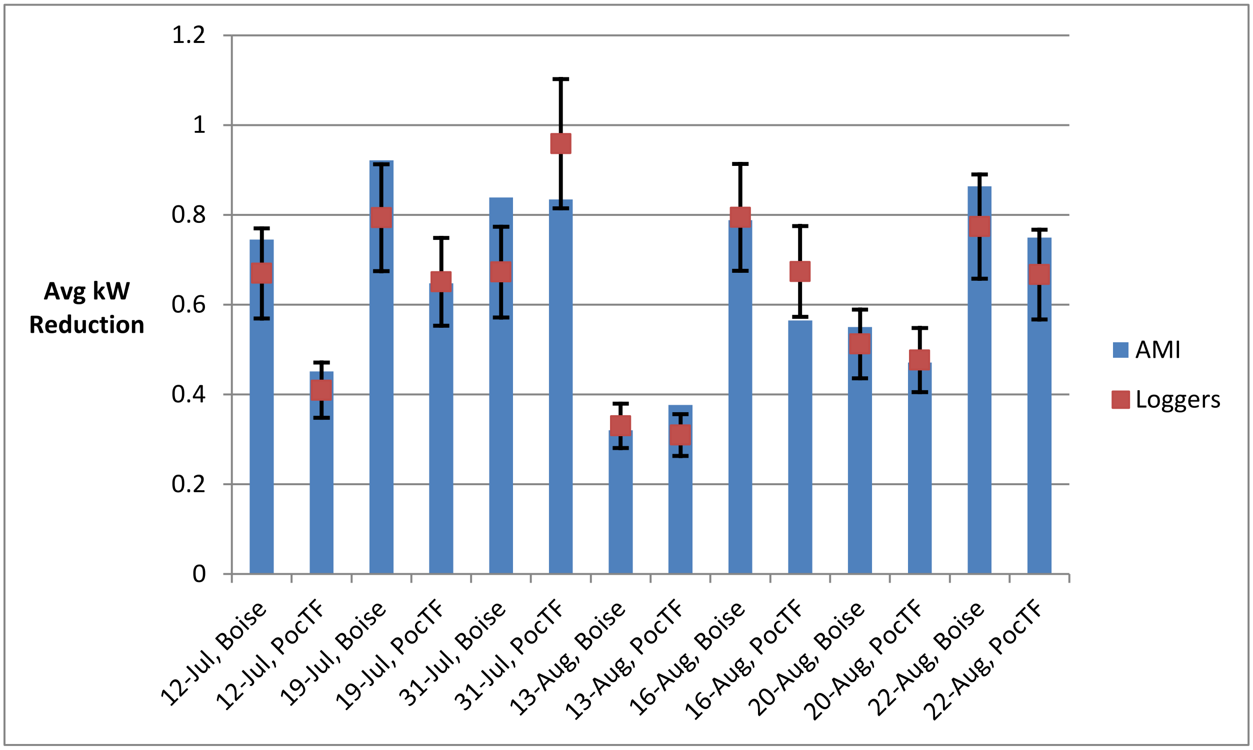


Figure 4. Average kW Reduction per Curtailment Event



Results from both data sets are used to investigate unexpected results from the 2012 season. The data from the two sources have very different profiles when graphed. The AMI data appears smooth, while the data from the loggers appears jagged. This difference is due to the time interval of the measurements. The AMI data is obtained hourly while the logger data is keyed to shorter time intervals of five minutes.

Individual Event Results

Table 12 summarizes the AMI data analysis results for each curtailment. Figure 5 shows an overview of the results for each curtailment event. Because temperatures in Boise Metro differ from the Twin Falls/Pocatello area, they are treated as separate events. The curtailment plan targeted events to take place in different temperature bins, the different bins are color coded. Each event is a unique occurrence as the events were called at different percentages and some at different time intervals. Each event is discussed in detail in the following section.

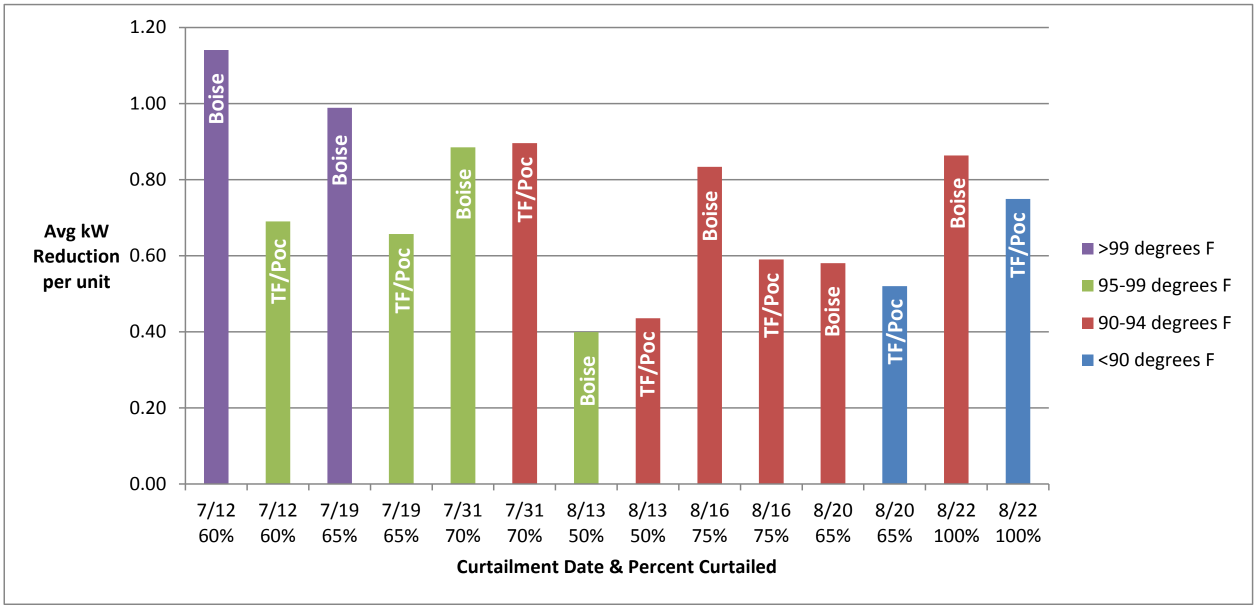
Results from both data sets are used to investigate unexpected results from the 2012 season. The data from the two sources have very different profiles when graphed. The AMI data appears smooth, while the data from the loggers appears jagged. This difference is due to the time interval of the measurements. The AMI data is obtained hourly while the logger data is keyed to shorter time intervals of five minutes.

Table 12. 2012 Summary Results of Executed Control Events

Date/ High Temp	% Curtail	Data source	Region	Max kW Reduction	Avg. kW Reduction
21-Jun Boise Metro: 95° TF/POC: 89°	65%	AMI	All	0.50	0.46
		AMI	Boise Metro	0.51	0.47
		AMI	Twin Falls/Pocatello	0.44	0.40
2-Jul Boise Metro: 95° TF/POC: 89°	100%	AMI	All	0.25	0.25
		AMI	Boise Metro	0.28	0.28
		AMI	Twin Falls/Pocatello	0.02	0.02
11-Jul Boise Metro: 99° TF/POC: 94°	60%	AMI	All	0.33	0.12
		AMI	Boise Metro	0.44	0.21
		AMI	Twin Falls/Pocatello	-0.24	-0.49
12-Jul Boise Metro: 106° TF/POC: 99°	60%	AMI	All	1.09	0.71
		AMI	Boise Metro	1.14	0.75
		AMI	Twin Falls/Pocatello	0.69	0.45
19-Jul Boise Metro: 104° TF/POC: 95°	65%	AMI	All	0.95	0.89
		AMI	Boise Metro	0.99	0.92
		AMI	Twin Falls/Pocatello	0.66	0.65
25-Jul Boise Metro: 97° TF/POC: 90°	50%	AMI	All	0.37	0.34
		AMI	Boise Metro	0.35	0.31
		AMI	Twin Falls/Pocatello	0.64	0.57
31-Jul Boise Metro: 97° TF/POC: 94°	70%	AMI	All	0.89	0.84
		AMI	Boise Metro	0.89	0.84
		AMI	Twin Falls/Pocatello	0.90	0.83
13-Aug Boise Metro: 97° TF/POC: 93°	50%	AMI	All	0.40	0.33
		AMI	Boise Metro	0.40	0.32
		AMI	Twin Falls/Pocatello	0.44	0.38
16-Aug Boise Metro: 93° TF/POC: 92°	75%	AMI	All	0.80	0.76
		AMI	Boise Metro	0.83	0.79
		AMI	Twin Falls/Pocatello	0.59	0.56
20-Aug Boise Metro: 94° TF/POC: 85°	65%	AMI	All	0.57	0.54
		AMI	Boise Metro	0.58	0.55
		AMI	Twin Falls/Pocatello	0.52	0.47
22-Aug Boise Metro: 90° TF/POC: 87°	100%	AMI	All	0.85	0.85
		AMI	Boise Metro	0.86	0.86
		AMI	Twin Falls/Pocatello	0.75	0.75

The curtailment plan organized requested events by temperature bin. Figure 5 below shows the curtailment results are organized by date and are indexed by temperature bin. Only event data used in development of the predictive tool are shown below. On each curtailment event day, the temperatures in the Boise Metro and Twin Falls/Pocatello areas are different; therefore, they are treated in the development of the predictive model as separate events entirely. In the table, each day has two events at different temperatures.

Figure 5. Curtailment Results by Temperature Bin



NOTE: Data from June 21, July 2, July 11 and July 25 is not included due to data anomalies described in the demand reduction results by event section.

June 21st Curtailment

One of the goals of the research was to verify the adaptive algorithm imbedded in the DRU devices was working as designed. Although the details of the algorithm are proprietary, the purpose of the adaptive algorithm is to reduce free ridership of program participants by taking into account previous runtime of the A/C unit when calculating the amount of time the A/C can run during a curtailment period. This is the only event where the devices relied on the adaptive algorithm. As a result of this curtailment, more was learned about how the device operates in Idaho Power's climate. After this curtailment, it was determined that utilizing a capped methodology for determining runtime, more similar to the LCT units, which does not consider previous runtime of the A/C unit is preferred to maintain consumer comfort and offer predictability of load shed to Idaho Power.

The event called on June 21st was executed at a temperature of 96 degrees in Boise Metro with a 65% curtailment strategy. For the LCT's, the curtailment was based on the number of available minutes in the event, a 65% curtailment prevents the device from running 65% of the time. The DRU's however, considered previous runtime when calculating the amount of time the device is allowed to run. The maximum kW reduction for a single hour during the curtailment demonstrates more reduction from the adaptive algorithm. The DRU devices yielded a maximum single hour reduction of 1.38kW and the LCTs delivered 0.85kW maximum kW reduction.

Although Idaho Power determined they would use a capped methodology for controlling the switches, the data from this event was examined to determine if a difference could be seen between the LCT units and the DRU units. Below are the graphs from the Boise Metro area only. The Twin Falls/Pocatello region has only DRU units. By comparing only the Boise Metro population, some variables are reduced.

Note that the y-axis (range of demand) scale on the graphs below varies based on the number of loggers or homes included in each analysis. The number of loggers/homes analyzed is dependent on the data source (logger or AMI data) and the curtailment event date. Table 13 below details the number of loggers/homes included in each graph. The June 21st curtailment event analysis included less than 100% of potential loggers because not all of the loggers were installed on the earliest baseline day (June 12th) for that event. Only loggers that were installed prior to that day were included in the analysis for June 21st.

Table 13. Loggers/Homes Analyzed by Curtailment Event

Date	*Data Source*	*Boise Metro*	*Twin Falls/Pocatello*	*Loggers/Homes Analyzed*	*Percent of Total*
21-Jun	Loggers - DRU	9	57	66	
	Loggers - LCT	12	--	12	
	Loggers - All	21	57	78	49%
All (except 21-Jun)	Loggers - All	102	57	159	100%
All	AMI	32,000	4,288	36,288	100%

Figure 6. June 21 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

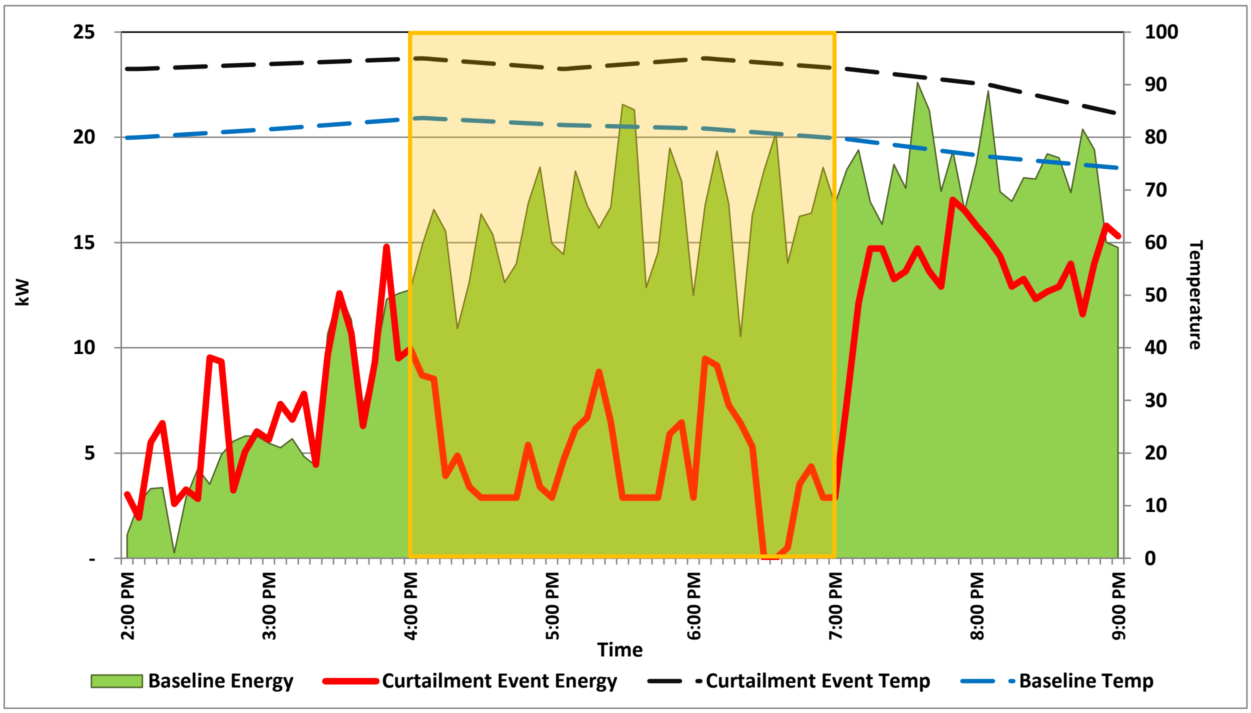
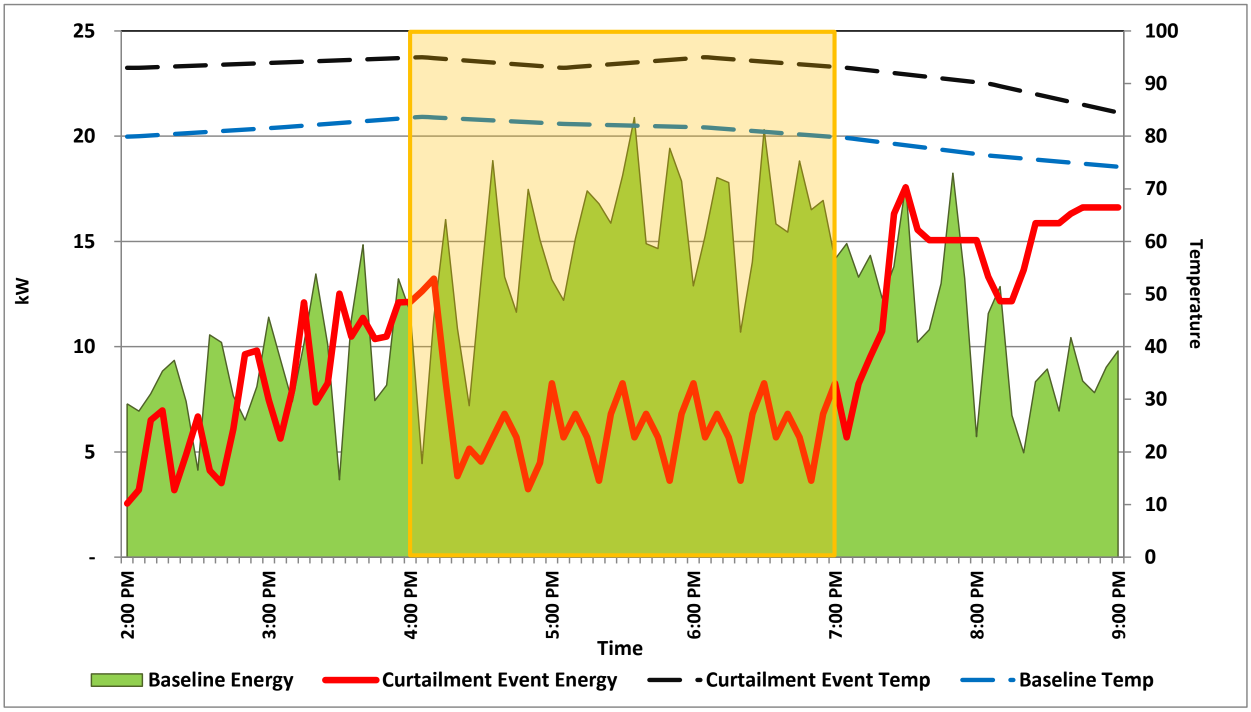


Figure 7. June 21 Curtailment Results: Loggers – Boise Metro Region (LCT Only)

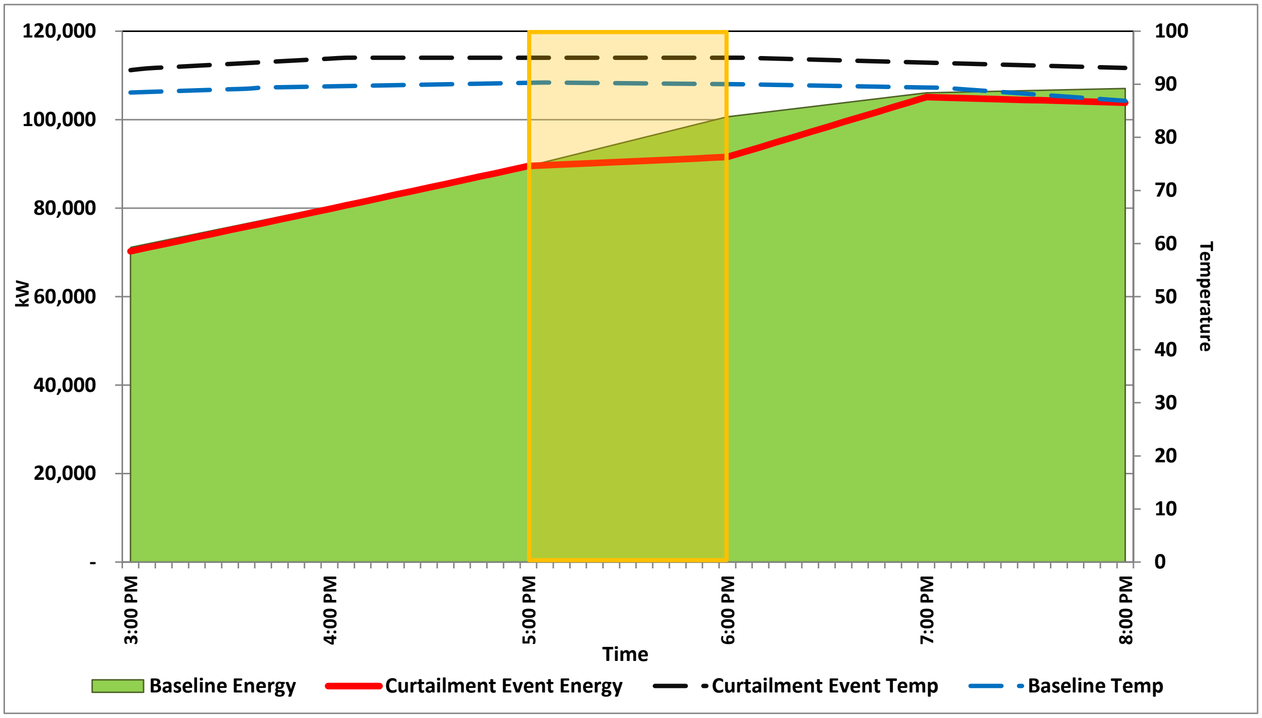


Idaho Power determined that the adaptive algorithm was not the preferred way to control devices for their climate and after this event all DRU devices were reprogrammed to operate using the capped methodology. This methodology does not differ from the operation of the LCTs. AMI data is utilized to analyze the remaining events, with some exceptions where more investigation was necessary.

July 2nd Curtailment

The curtailment scheduled on July 2nd was intended to be a one hour curtailment at 100%. Per the curtailment plan, 100% events were scheduled for temperatures less than 90 degrees and for only 1 hour durations to minimize customer discomfort. On July 2nd, the temperature rose above 90 degrees so the event was canceled. However, only the DRU group was canceled, the LCT group did not get canceled. Since a curtailment event occurred, the data was analyzed, but is not included in the data for the predictive model. All LCT's are located in the Boise Metro region. Therefore the results for the Twin Falls/Pocatello region are not shown. Calling only the LCTs yielded a single hour demand reduction of 0.28 kW per unit in the Boise Metro area. Since the event was only one hour long, this represents both the maximum and average demand reduction.

Figure 8. July 2 Curtailment Results: AMI – Boise Metro Region



July 11th and 12th Curtailments

Back to back curtailments were called on July 11th and July 12th. July 12th was Idaho Power's system peak day. The table below shows the temperatures on each day in both areas as well as the curtailment strategy. The paging units (LCRs) were called to curtail from 4:00-7:00pm. The power line carrier devices (LCTs and DRUs) were controlled from 5:00-8:00pm.

Date	Boise Metro Hi Temp	Pocatello Hi Temp	Strategy	Time	Max Demand Reduction Boise Metro (kW)	Max Demand Reduction TF/Poc. (kW)
July 11th	99	94	60%	LCRs 4-7pm, LCTs/DRUs 5-8 pm	0.44	-0.24
July 12th	106	99	60%	LCRs 4-7pm, LCTs/DRUs 5-8pm	1.14	0.69

Given the similar nature of the two events, the results were expected to produce similar patterns and load reductions. However, according to the data, this was not the case. The figures below show the entire system results for the two days.

Figure 9. July 11 Curtailment Results: AMI – Both Regions

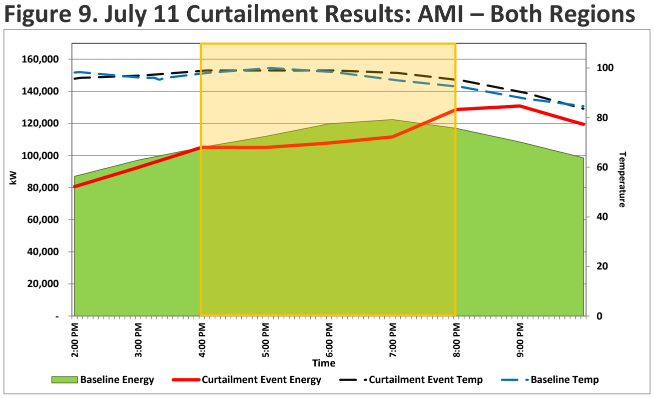
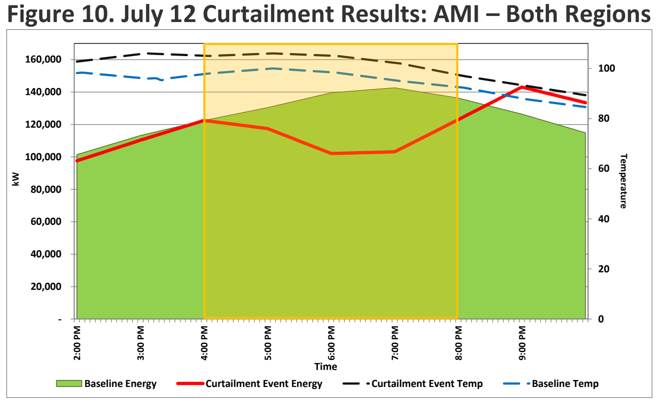


Figure 10. July 12 Curtailment Results: AMI – Both Regions



It appeared that on July 11, only the group called from 4:00-7:00 pm responded to the control event. As seen in both Figure 9 and Figure 10 above, it is evident that the total kW demand drops starting at 4pm. However, only Figure 10 shows a further drop in demand at 5pm for when the second group is called. This suggests that the second group was not called during the July 11 curtailment event. To investigate this further, logger data from the DRU's and LCTs on July 11 was examined. The figures below show the curtailment results from the loggers placed in the Boise Metro area. The DRU's show no response where the LCT devices clearly are activated at 5:00pm as intended.

Figure 11. July 11 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

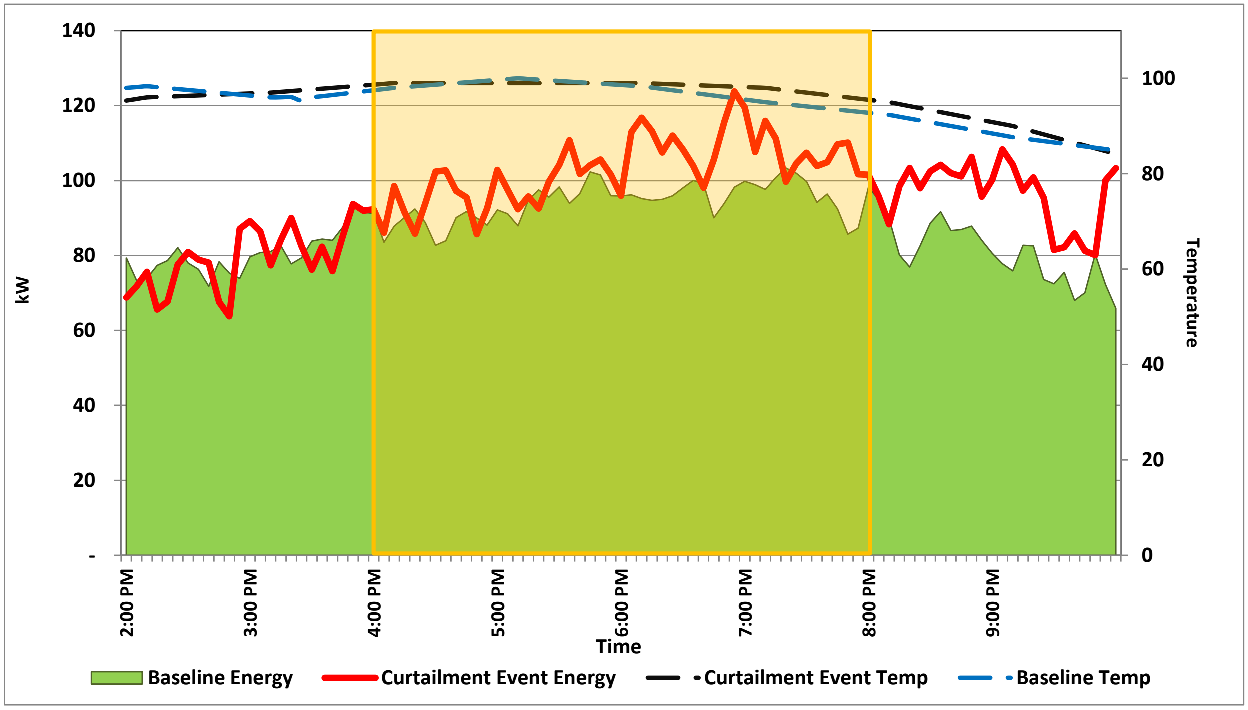
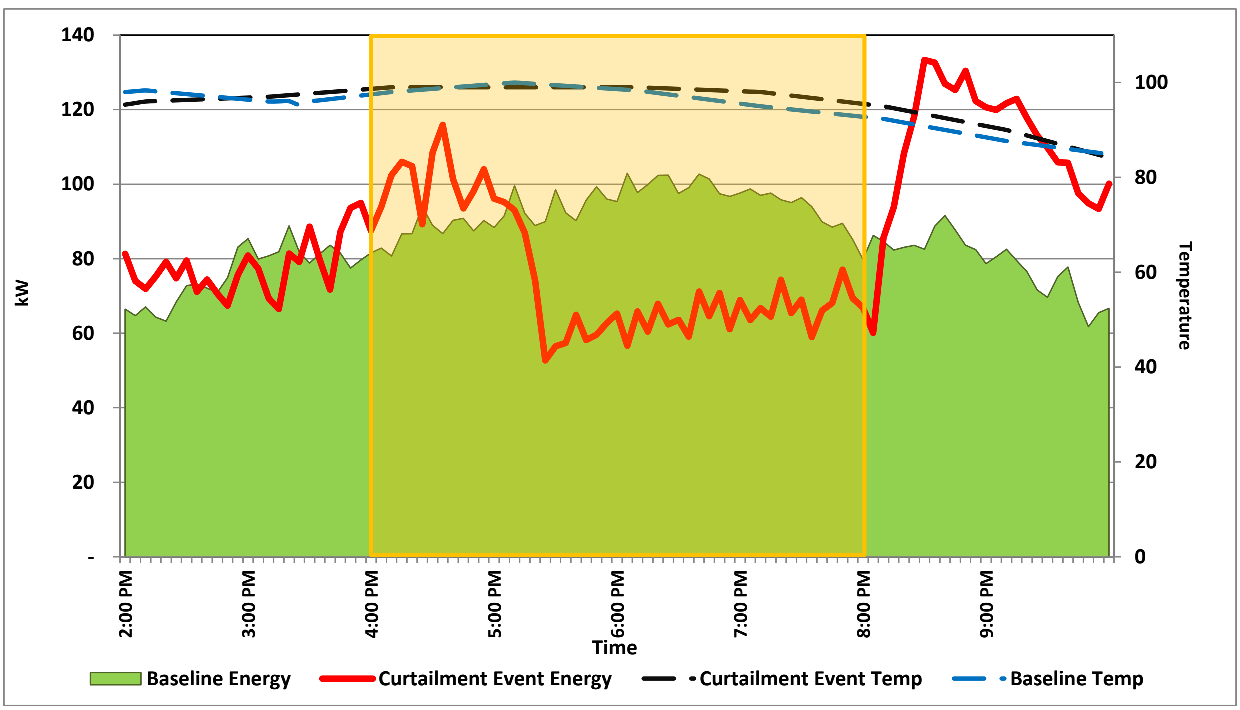


Figure 12. July 11 Curtailment Results: Loggers – Boise Metro Region (LCT Only)



The event called on July 12th resulted in a system wide average demand reduction for one hour of 1.09 kW per participant. In the Boise Metro area, the average 1 hour max reduction was 1.14 kW and in the Twin Falls/Pocatello area it was 0.69 kW per participant.

July 19th Curtailment

As expected with the high temperature in Boise of 104° (and 96 in the Twin Falls/Pocatello area) for the July 19 curtailment, the 65% curtailment yielded a significant load shed for this timeframe. The event ran from 4:00-7:00 pm. The maximum kW reduction in the Boise Metro area was 0.99 kW and the maximum single hour kW reduction in the Twin Falls/Pocatello area was 0.66kW.

Figure 13. July 19 Curtailment Results: AMI – Boise Metro Region

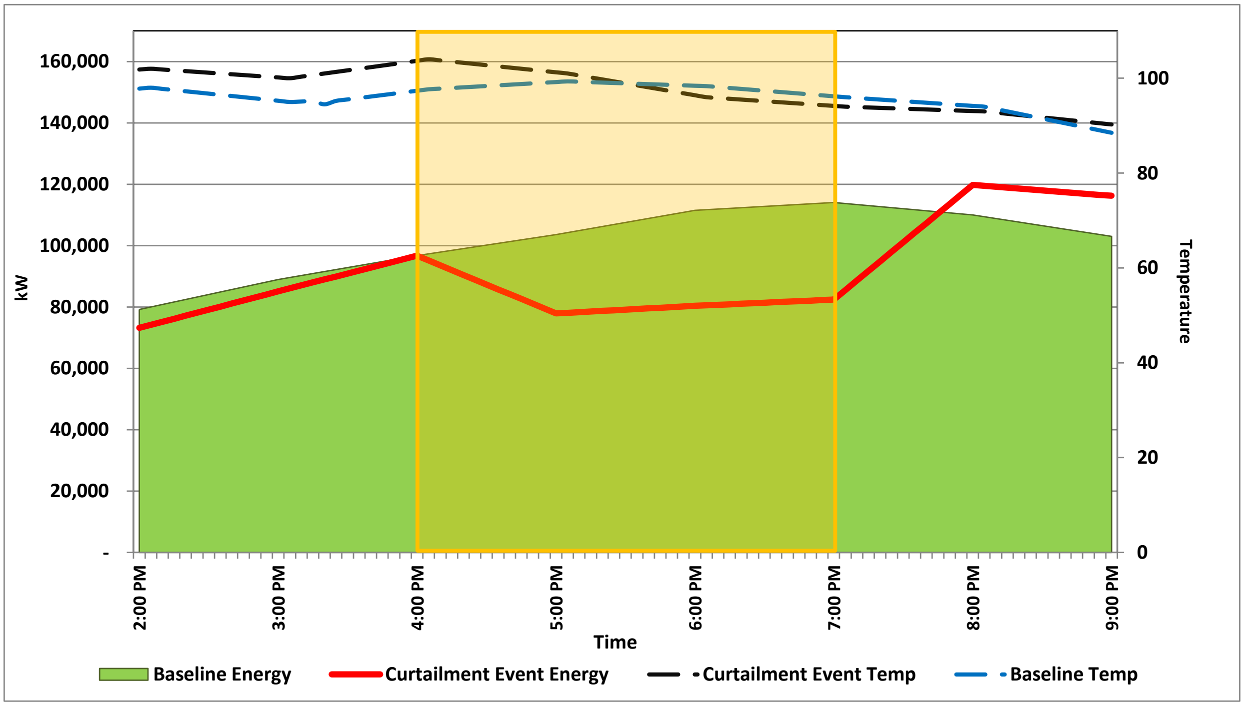
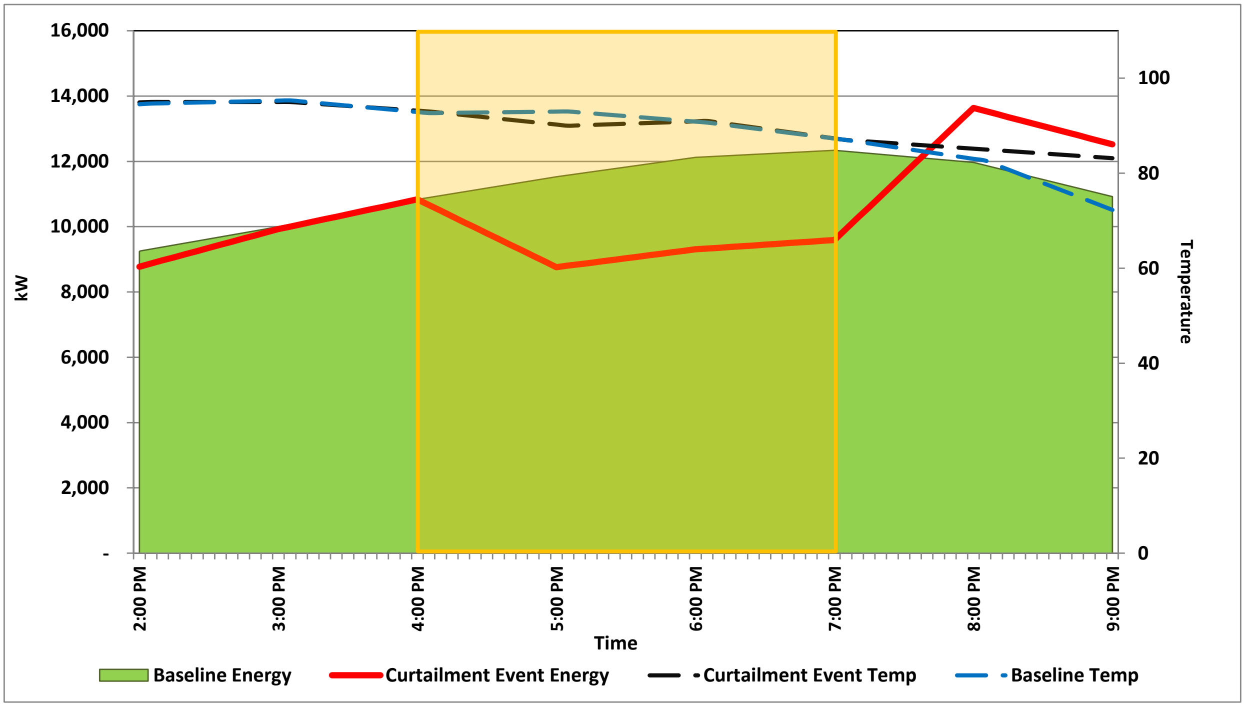


Figure 14. July 19 Curtailment Results: AMI – Twin Falls / Pocatello Region



July 31st Curtailment

On July 31st, a curtailment at 70% was executed, but because of concerns regarding customer comfort, the event was shortened to two hours. The maximum load reduction in the Boise Metro area was 0.89kW and the Twin Falls/Pocatello area achieved a maximum kW reduction for a single hour of 0.90 kW. While the curtailment was at a high percentage, the measured increase in indoor air temperature in the Boise Metro area averaged only 0.53 degrees during the curtailment with a maximum increase of 1.09 degrees. A more complete discussion on the indoor air temperature analysis is in the section titled “Indoor Temperature Analysis Results”

Figure 15. July 31 Curtailment Results: AMI – Boise Metro Region

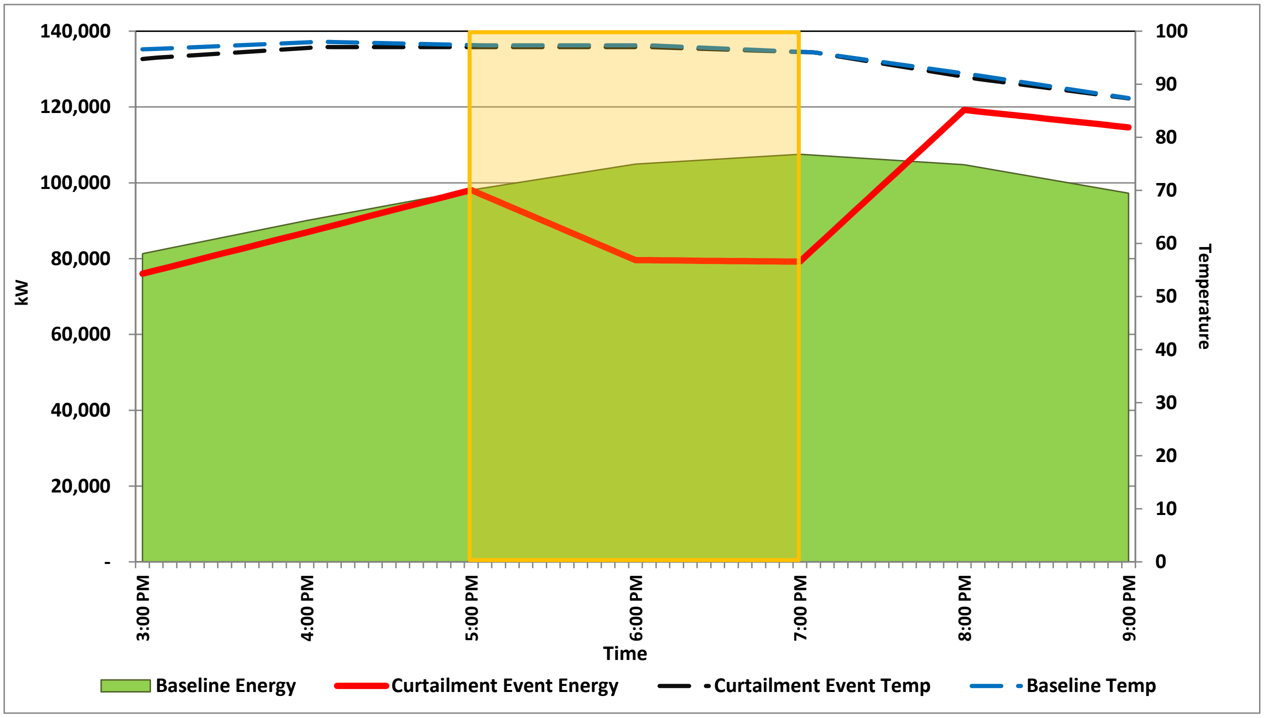
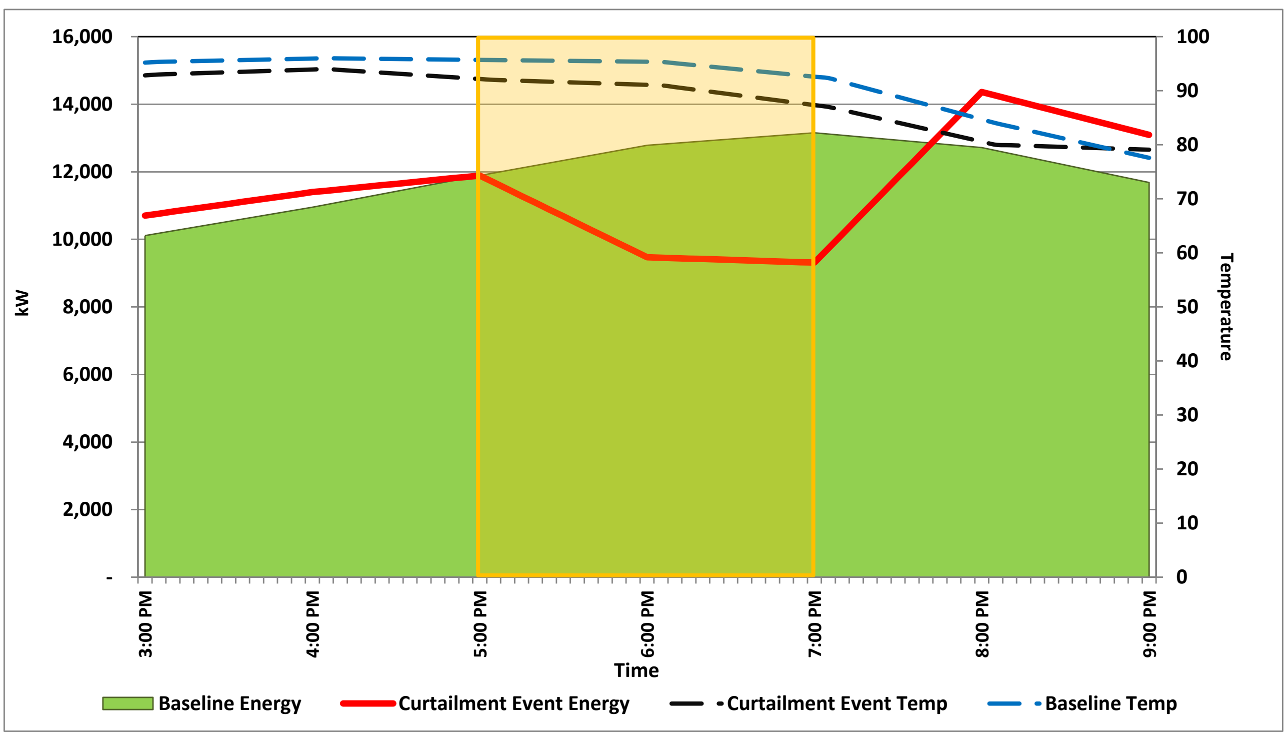


Figure 16. July 31 Curtailment Results: AMI – Twin Falls / Pocatello Region



July 25th and August 13th Curtailments

The program team wished to gather data at a 50% curtailment and executed two events at this level, one on July 25th and one on August 13th. The overall results were very similar from a system perspective; however on July 25th the kW per unit achieved in the Twin Falls/Pocatello area is nearly twice as much as the Boise Metro area. This result was unexpected, especially since the temperature in Boise was higher and therefore A/C use was expected to be higher.

Region	July 25th		August 13th	
	Hi Temp	Max kW Reduction	Hi Temp	Max kW Reduction
Boise Metro	97	0.35	97	0.40
TF/Pocatello	90	0.64	93	0.44

Figure 17and Figure 18 below show the system wide results for the curtailments on these two days. The overall results appear similar; however the analysis of the individual events reveals unexpected differences.

Figure 17. July 25 Curtailment Results:
AMI – Both Regions

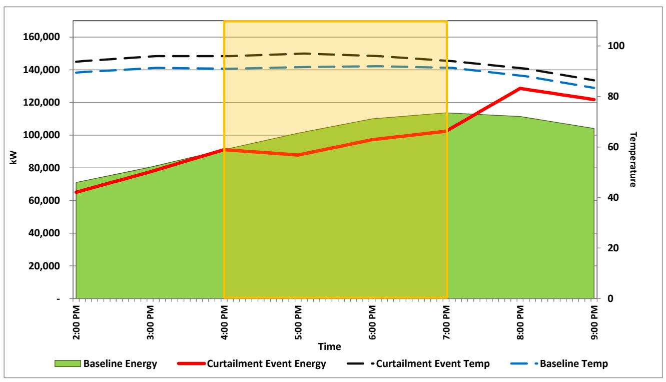


Figure 18. August 13 Curtailment Results:
AMI – Both Regions

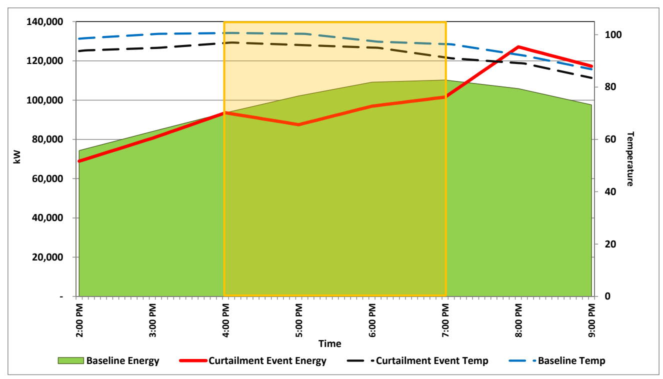


Figure 19 – Figure 22 show the curtailment results both regions on these two days. It is important to note that the scale differs between individual graphs for the Boise Metro and Twin Falls/Pocatello regions; however, the intensity of the load reductions should be similar. The difference can be seen when comparing Figure 19 and Figure 20.

Figure 19. July 25 Curtailment Results:
AMI – Boise Metro Region

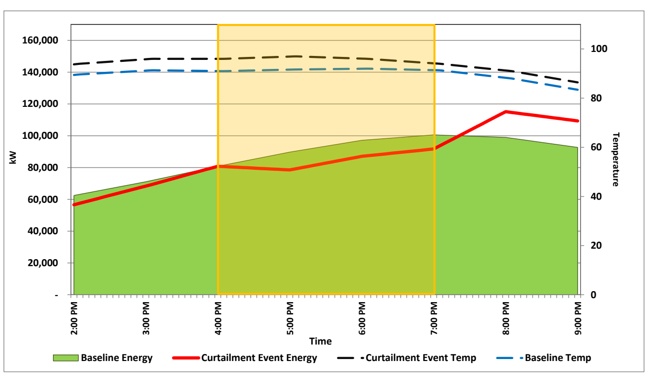
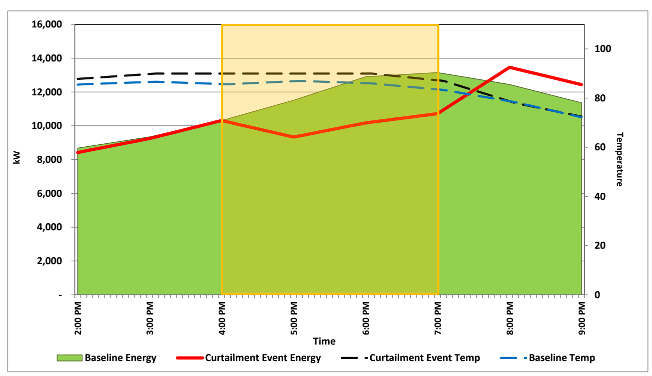


Figure 20. July 25 Curtailment Results:
AMI – Twin Falls / Pocatello Region



The load reductions shown in Figure 21 and Figure 22 are in line with expectations as well as measured results from 2011.

Figure 21. August 13 Curtailment Results:
AMI – Boise Metro Region

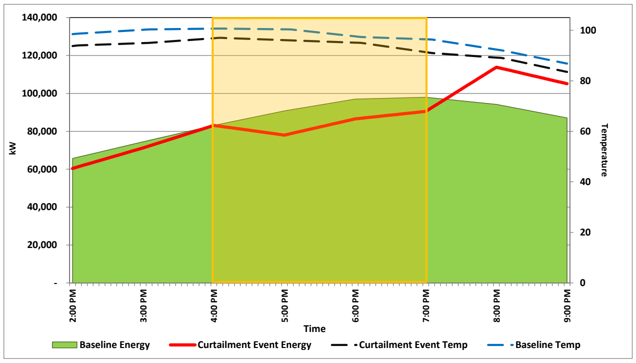
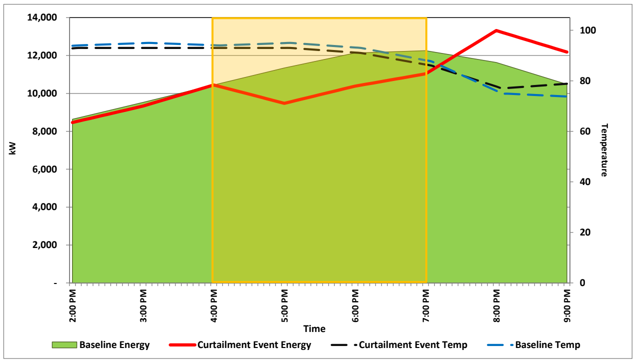


Figure 22. August 13 Curtailment Results:
AMI – Twin Falls / Pocatello Region



Logger data was examined to see if there was an explanation for these results. The curtailment was executed at 50% which is close to the natural duty cycle of the A/C units. The LCT unit results (Figure 23) more clearly show demand savings during this curtailment, however because the cycling is so close to the natural duty cycle the demand reduction is small. The DRU unit results are less clear, however this could be explained by variability in the baseline days, localized cloud cover, and a high temperature of only 90 degrees. The combination of these factors contributes to the reduced savings that are visible in the analysis. One factor that does point to savings reductions as a result of the units being controlled is an apparent “snap back” effect even where a demand reduction is less apparent. Analysis of the logger data from the Twin Falls/Pocatello area (Figure 25), which are also DRU devices, shows a definite demand reduction during the curtailment event.

Figure 23. July 25 Curtailment Results: Loggers – Boise Metro Region (LCT Only)

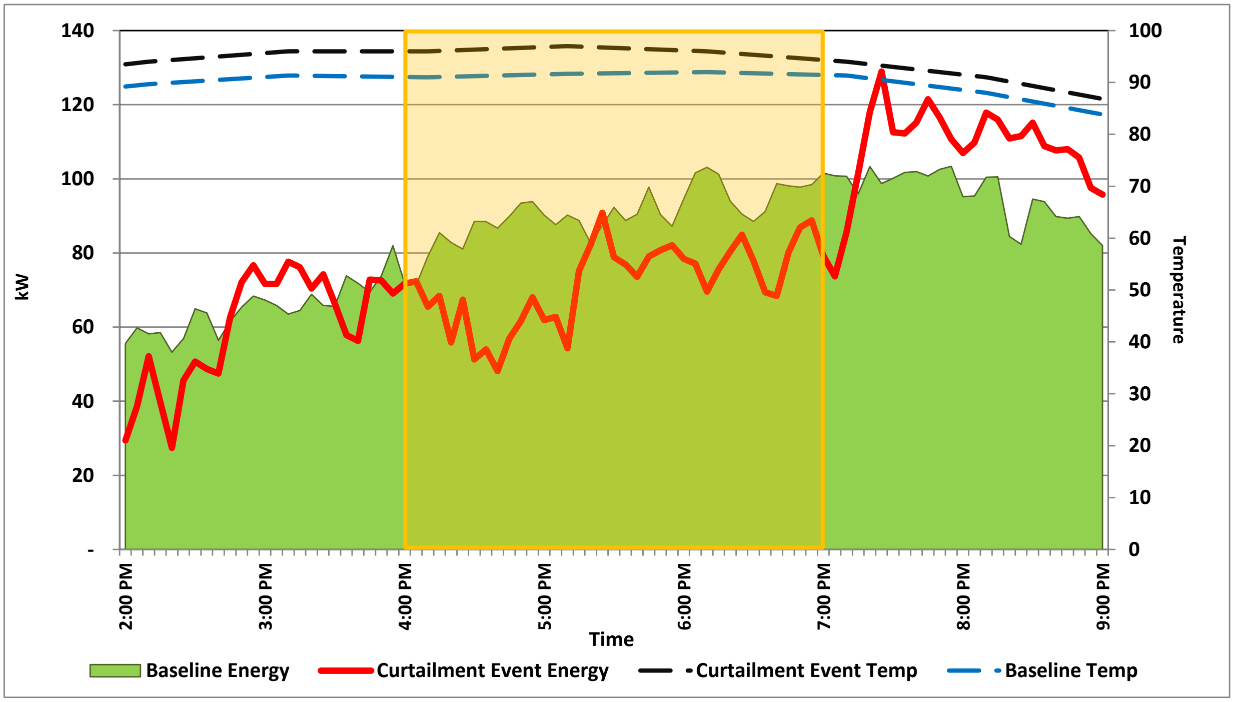


Figure 24. July 25 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

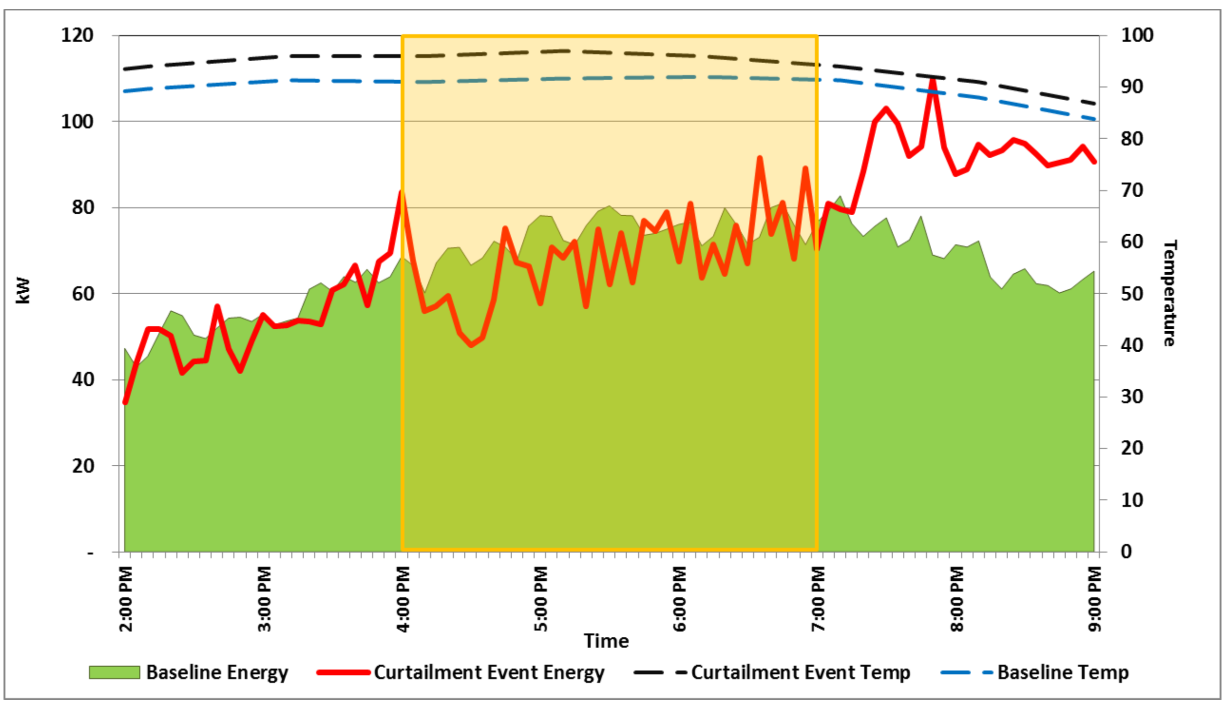
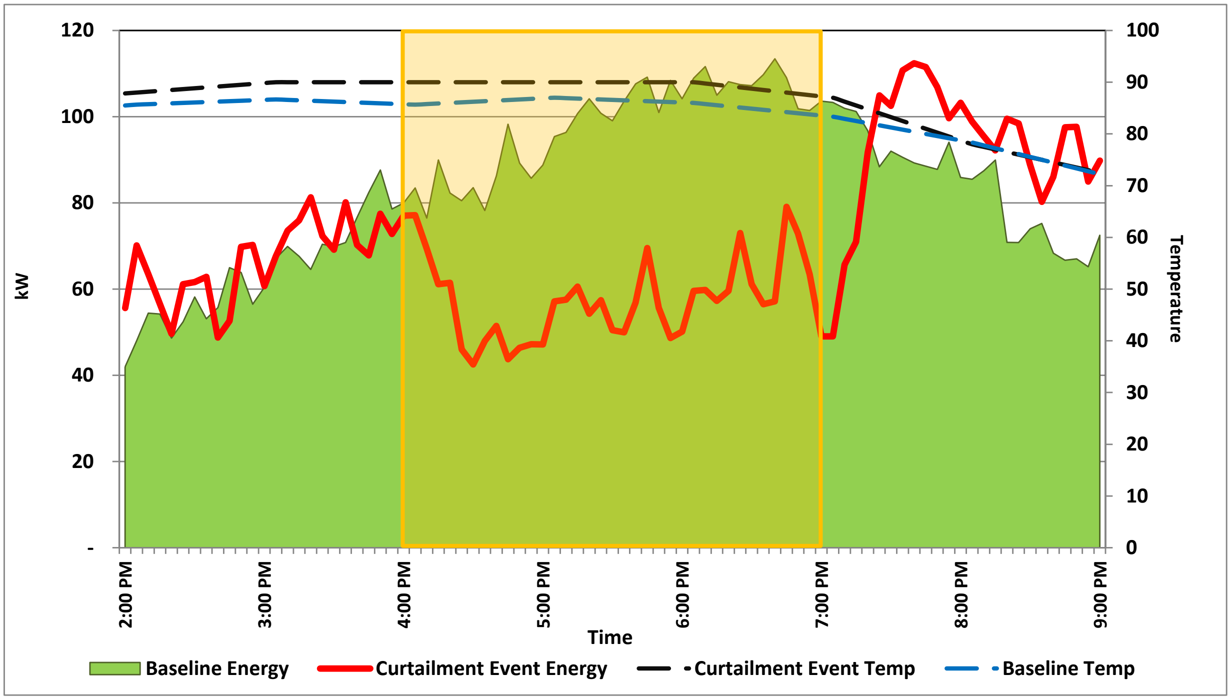


Figure 25. July 25 Curtailment Results: Loggers – Twin Falls / Pocatello Region



August 16th and August 20th Curtailments

The August 16 load curtailment event executed at 75% shows a reasonable kW reduction in both areas relative to temperature. The event on August 20th executed at 65% yielded a smaller demand reduction as expected.

Date	Boise Metro Hi Temp	TF/Poc Hi Temp	Times	% Curtail	Max kW Reduction Boise Metro	Max kW Reduction TF/Poc
Aug 16	93	92	4-7 pm	75%	0.83	0.59
Aug 20	94	86	4-7 pm	65%	0.57	0.52

Figure 26 August 16 Curtailment Results

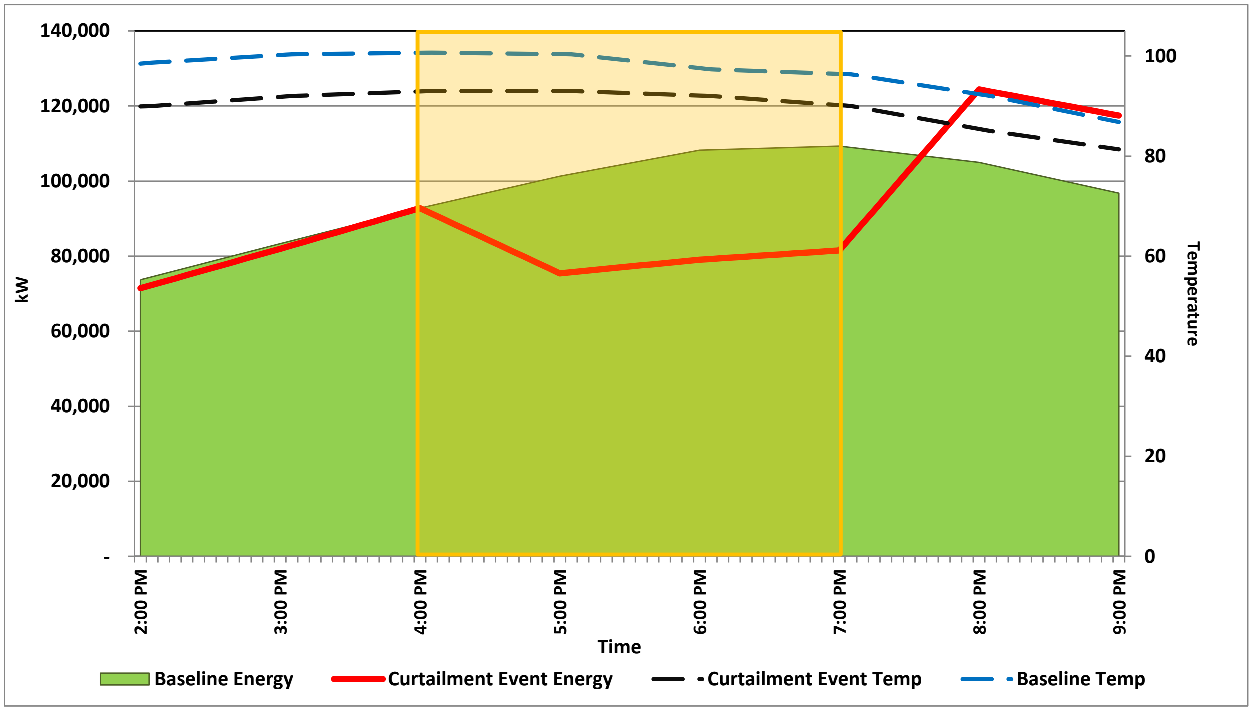
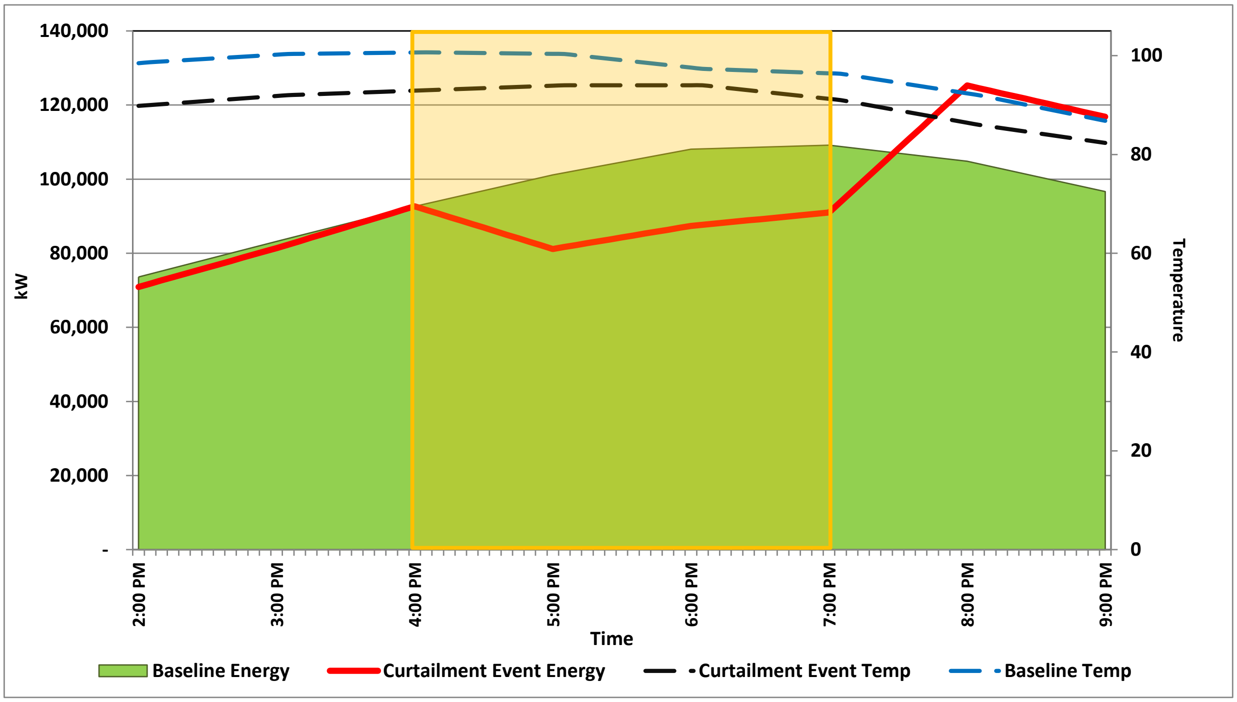


Figure 27 August 20 Curtailment Results



August 22nd Curtailment

The final curtailment event for the season was at 100% for one hour. Since the first 100% event had been canceled prior to full execution, a second event was called on August 22. The curtailment was intentionally executed at a low temperature to minimize any customer comfort impacts of a complete load shed. In spite of a relatively low temperature for a curtailment, the data shows good load reduction for the shed event. The event was conducted between 5:00 and 6:00pm and achieved a maximum kW reduction in Boise Metro of 0.86kW and 0.75 kW in the Twin Falls/Pocatello Area.

Figure 28. August 22 Curtailment Results: AMI – Boise Metro Region

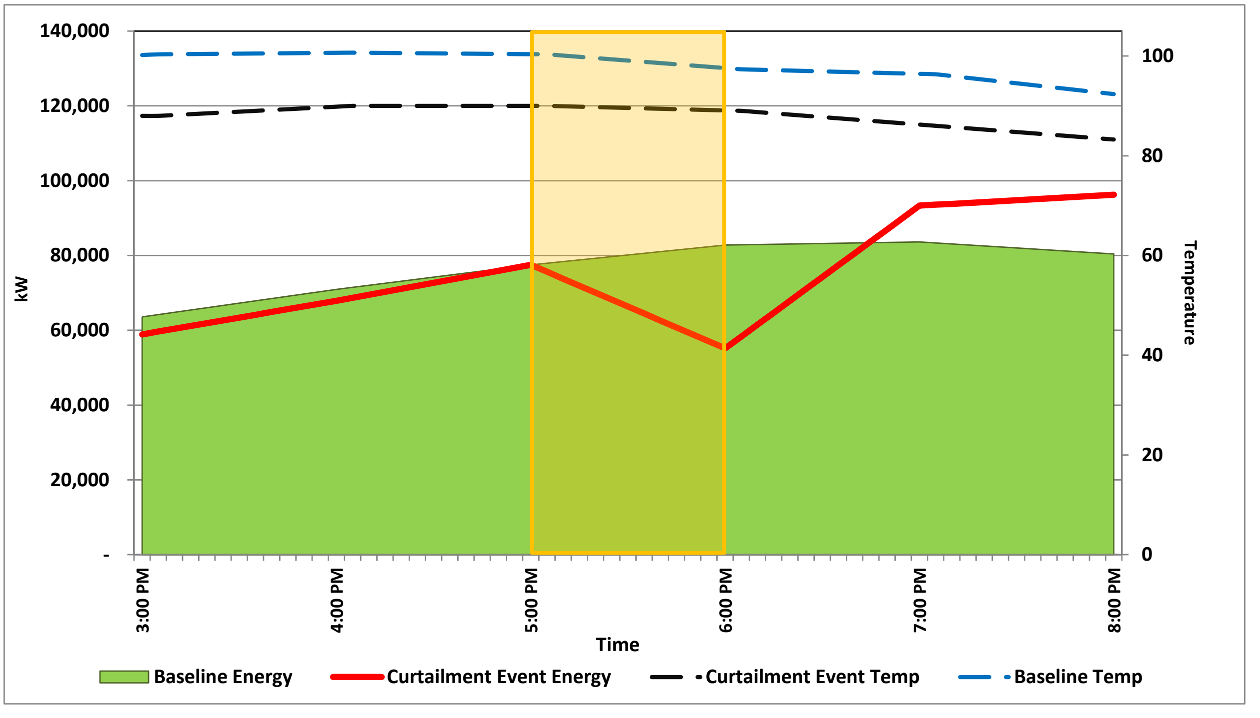
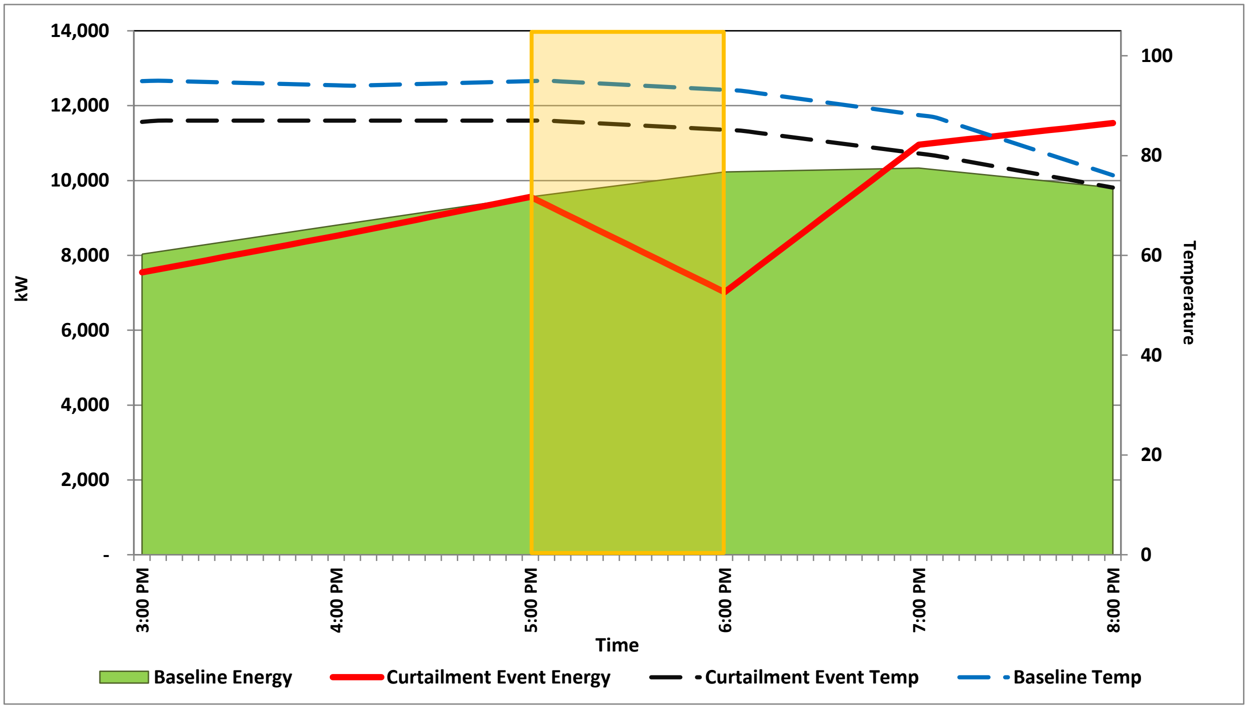


Figure 29. August 22 Curtailment Results: AMI – Twin Falls / Pocatello Region



Indoor Temperature Analysis Results

A potential concern of running demand response events that curtail customers' A/C units is the impact on indoor air temperature (IAT) and occupant comfort in the home during the curtailment event. To understand how much IAT is impacted during the curtailment event, temperature loggers were installed in a subset of participants' homes. The resulting data from the IAT loggers was analyzed to investigate how much IAT increased as a result of the homes' A/C units being cycled.

This analysis was completed for both the Boise Metro and Twin Falls / Pocatello region participants. The average temperature increases for the Boise Metro population is shown in Figure 30 below, and the maximum temperature increase is shown in Figure 31. The IAT increase per curtailment event was 0.55°F on average and ranged from -0.14°F to 1.49°F. The maximum temperature increase was 1.01°F on average and ranged from 0.23°F to 2.39°F. This sort of variation is well within the range of temperatures reported on Idaho Power's online FAQ[2] which states that "participants in the program in 2003-2004 experienced an overall average increase in home temperature of less than two degrees" and that "nearly 90 percent of homes experienced less than a four-degree temperature increase."

[2] http://www.idahopower.com/EnergyEfficiency/Residential/Programs/ACCoolCredit/ACfaqs.cfm#14

Figure 30. Average IAT Increase

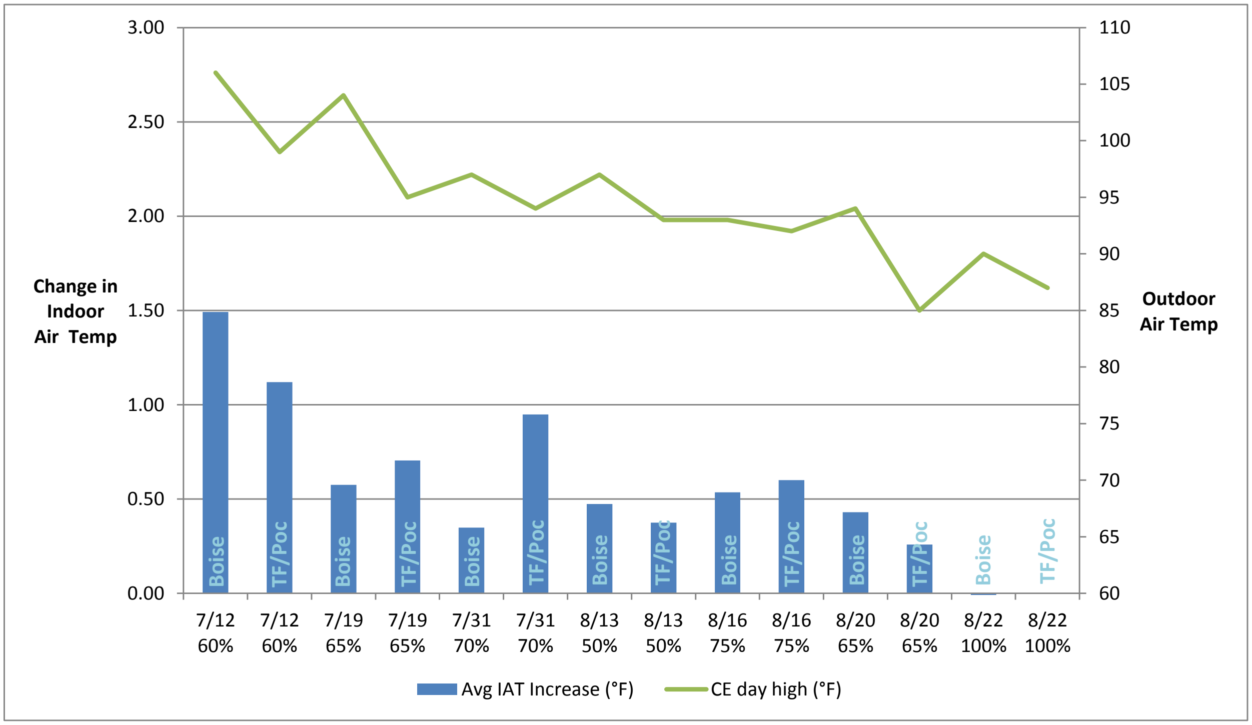
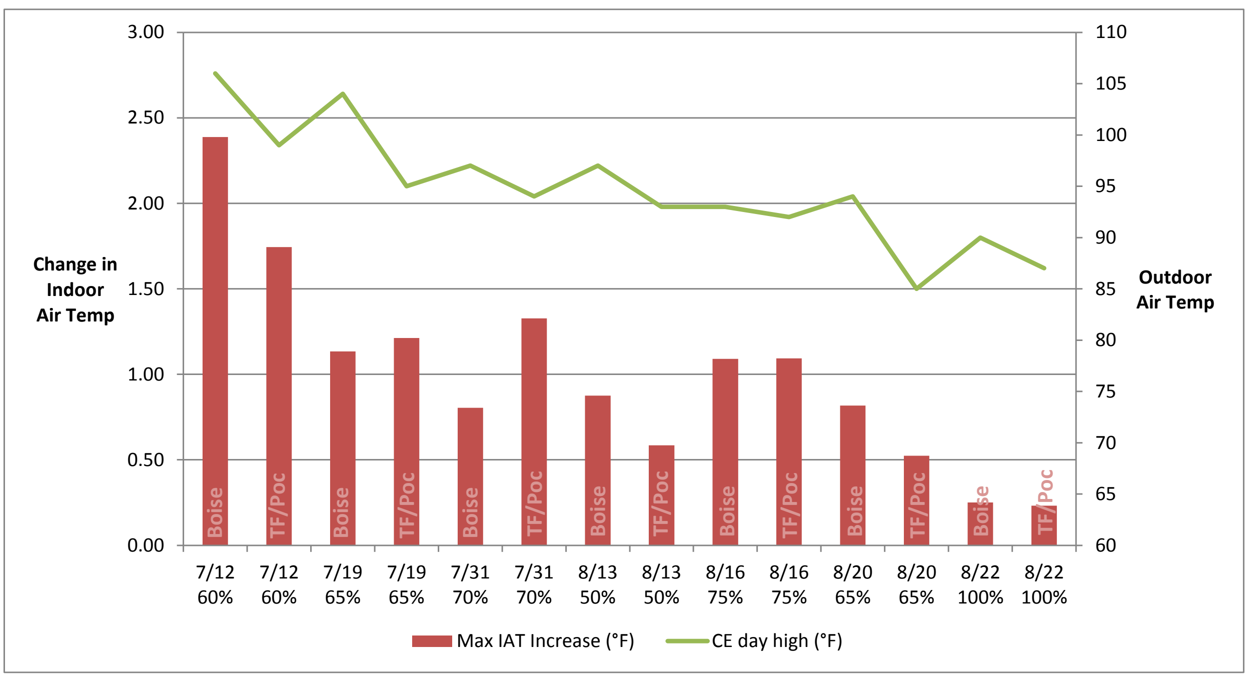


Figure 31. Max IAT Increase



It is evident that increases in IAT are correlated to outside air temperature, percent curtailment, and the length of the curtailment. The event on July 12th illustrates a high outside air temperature scenario; the high temperature on that day was 106 degrees, and consequently, the event on that day provided the largest change in IAT. Figure 32 shows the plot of indoor air temperature for July 12th. The red line shows the baseline temperature and the blue line indicates the temperature for the curtailment day.

The event on August 22nd shows the effects of a very short curtailment in low temperature conditions. Even though participants were curtailed at 100%, the average IAT increase was close to 0, and the max was around 0.25 degrees. This is because the curtailment period only lasted one hour and the temperature in Boise Metro and the Pocatello / Twin Falls area was low compared to other event days.

July 31st is also of interest as the curtailment was shortened due to concerns regarding customer comfort. Figure 34 shows the indoor air temperature variation on that day in Boise Metro. As shown in the chart, indoor air temperature was 0.8 degrees above the baseline scenario during the curtailment. Since the baseline model is consistently about 1 degree higher than the actual indoor air temperature, we also compared the maximum temperature rise from the temperature right before the curtailment period. That comparison only resulted in a 1.8 degree increase in indoor air temperature.

Figure 32. July 12th IAT Increase: Boise Metro

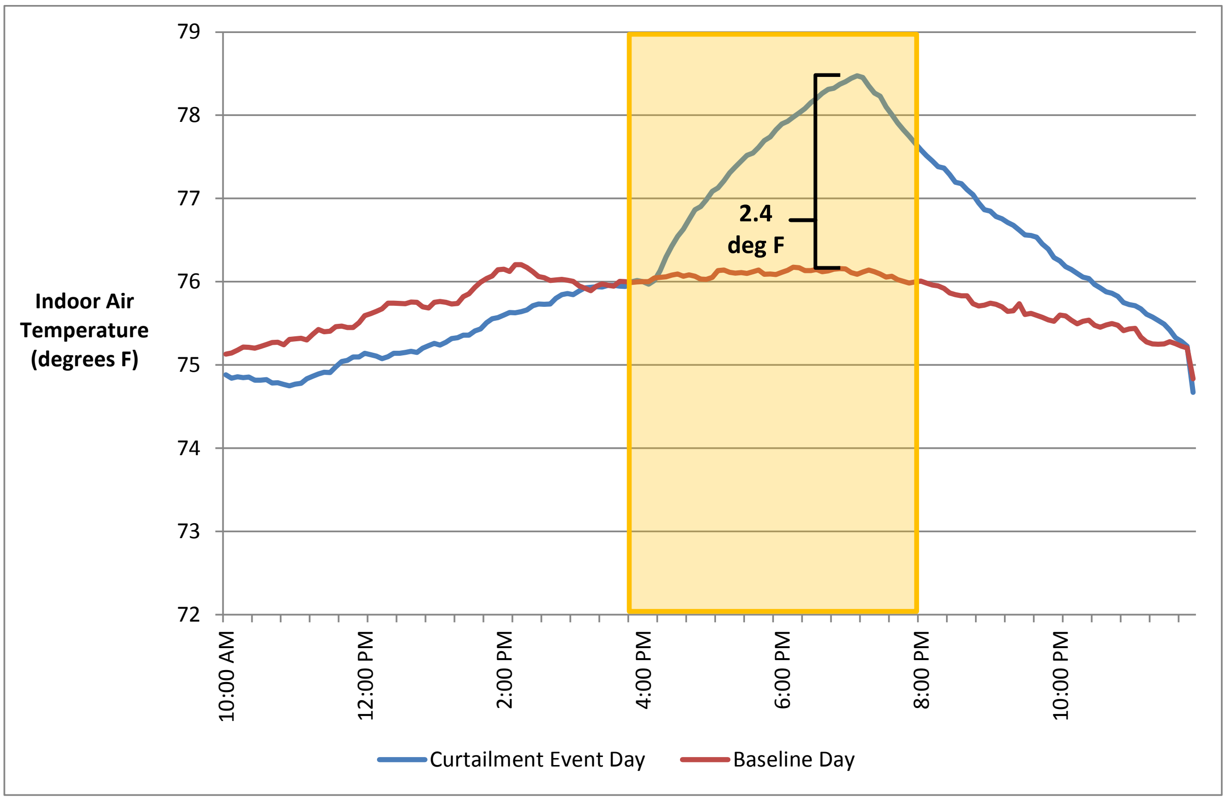


Figure 33. July 12th IAT Increase: Twin Falls / Pocatello

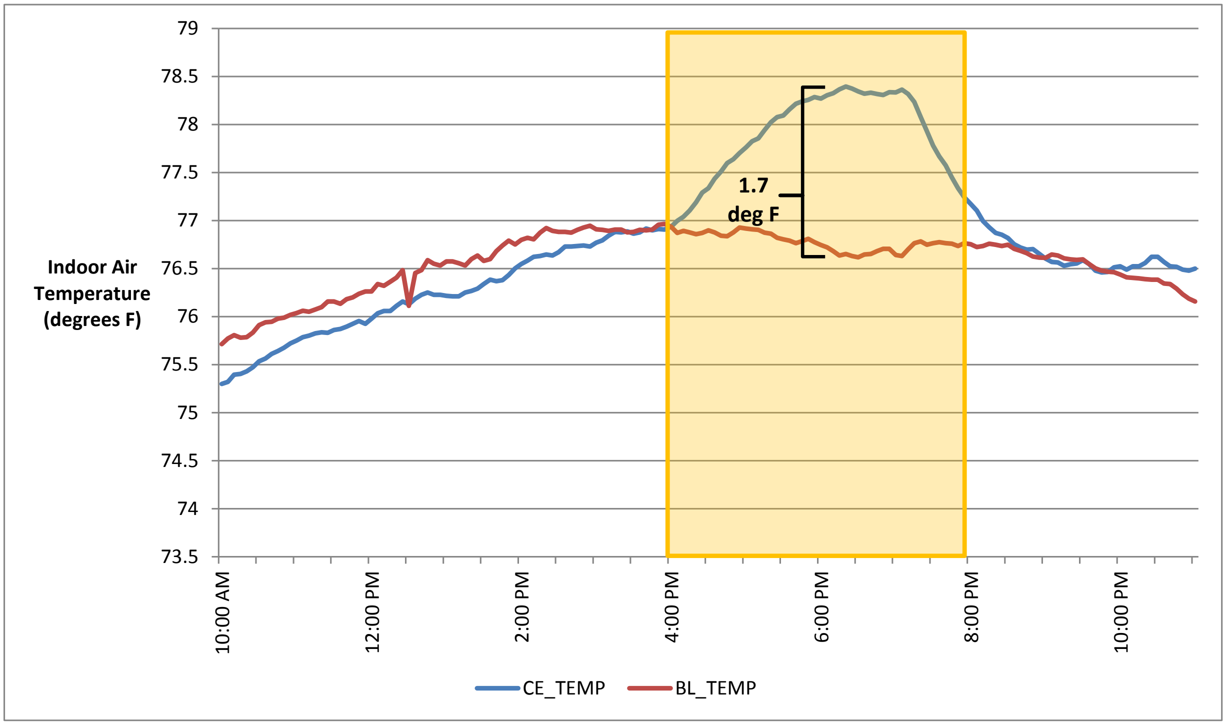
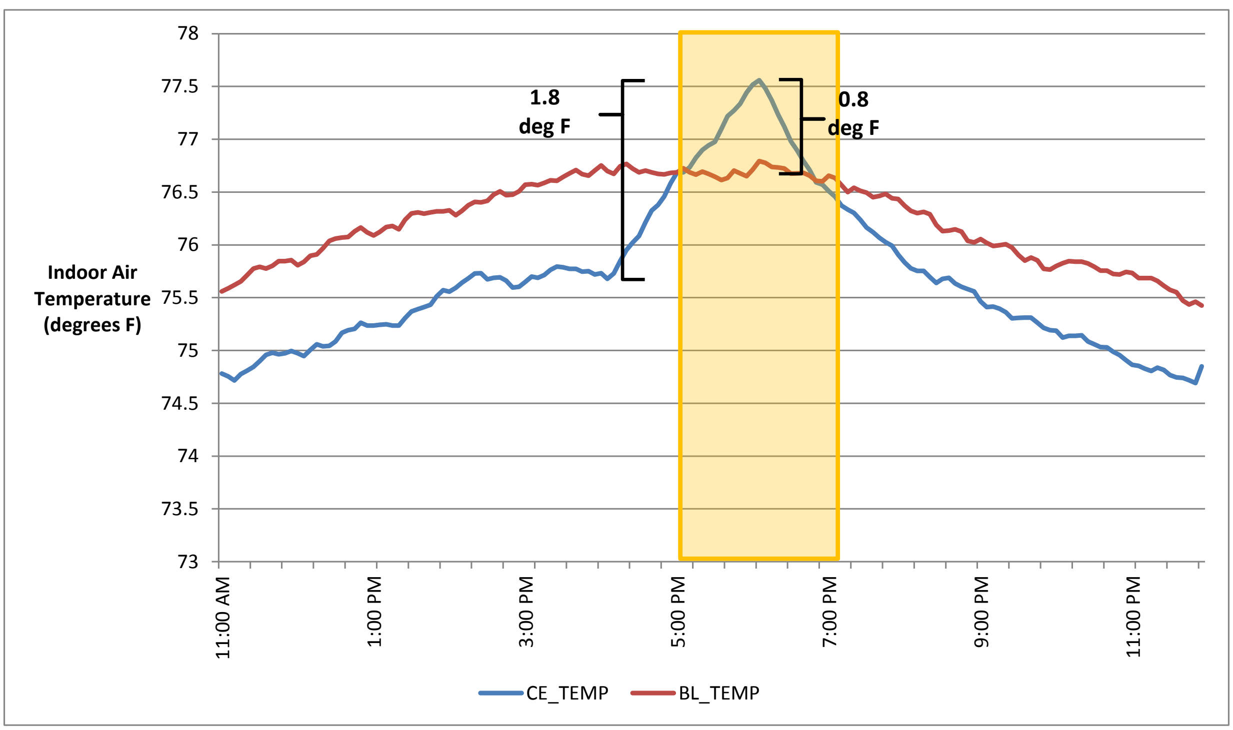


Figure 34. July 31st IAT Increase: Boise Metro



Conclusions

PECI conducted research on behalf of Idaho Power to identify optimal curtailment strategies to meet cost-effectiveness targets and develop a predictive model that correlates weather forecasts with achievable kW load shifts from curtailment events.

The goals of this research were to:

- Verify that savings can be estimated using AMI data.
- Verify the adaptive algorithm is working as designed.
- Estimate kW reductions at different temperatures and cycling strategies.
- Create a predictive model for planning purposes.
- Test the comfort impacts of higher cycling strategies to find the optimum curtailment strategy that maximizes kW results with minimum comfort impacts.

The research successfully addressed these research goals.

The analysis shows that AMI data can be used to reliably estimate demand reduction of curtailment events. Even though the AMI meters and loggers measure slightly different parameters, these sources produce similar estimations of energy reduction per curtailment event. The AMI data is less expensive and faster to obtain, represents a census of the program population, and will take into account behavioral changes as a result of curtailment events. PECI recommends that Idaho Power utilize their AMI data for future research, evaluating events in real time for program management, as well as impact evaluations.

The data collected also shows that the adaptive algorithm available in the DRU devices does work as designed. While data from only one curtailment event was examined, the evidence supports this conclusion. The demand reduction achieved from the DRU devices was significantly larger than from the older LCT devices. The DRU devices yielded a maximum single hour reduction of 1.38kW and the LCTs delivered 0.85kW maximum kW reduction. During the research, more was learned about how the algorithm calculates previous runtime. Idaho Power has determined that this calculation results in more customer discomfort at the beginning of the cooling season and has decided not to use this feature at this time, relying instead on a capped methodology which limits runtime based on the length of the curtailment event and not prior usage.

Using the data collected from the loggers as well as the AMI data provided by Idaho Power, demand reduction estimates are provided for each cycling event. Idaho Power program staff sought to optimize curtailment strategies to balance the demand reduction and participant comfort. Therefore, the events executed during the 2012 curtailment season were conducted at different cycling strategies and outdoor high temperatures. The curtailments executed were successful and no system failures were evident during the analysis. Human error was detected on two event days. The data from these days was not usable for creating the predictive model, but the analysis can be used to detect errors and correct them for future events. Other general conclusions cannot be drawn regarding the events in total; however the entirety of the data is useful in creating a predictive model for planning purposes.

PECI utilized the analysis from each cycling event to build a predictive tool for planning purposes. The “IPC Curtailment Calculator” was developed with the aim of providing IPC with a tool for estimating demand reduction levels based on temperature and cycling percentage inputs. A regression formula was developed for both regions (Boise Metro & Pocatello/Twin Falls) based on the independent variables of “Temperature at start of curtailment event,” “Percent cycling,” and the interactive effect of the two variables. The Excel-based calculator was then developed using the regression formula for each region. The regression formula is based on the “Average kW per unit” metric, and not “Max kW per unit.” This is due to the fact that the “Max kW per unit” metric does not produce statistically significant results in a regression based on the independent variables of “Temperature at start of curtailment event,” “Percent cycling,” and the interaction between the two. However, to enable Idaho Power to use the calculator to estimate max kW per unit for planning purposes, PECI analyzed the relationship between the average and max kW. As a result, the average kW returned by the model is scaled up by 11% to estimate the max kW reduction for a planned event. This is sufficient for planning purposes but should not replace post event evaluation. It is recommended that Idaho Power continue to collect data in future curtailment seasons to refine the model. It is possible, with more data points in the regression, the calculator can be revised to predict “Max kW per unit” for planning purposes and eliminate the need to scale the results.

Higher cycling strategies do have an impact on indoor air temperature. These increases, on average, have minimal impacts to overall customer comfort. Individual homes may have higher impacts due to differences in system design and the energy efficiency of the home. The IAT increase per curtailment event was 0.55°F on average and ranged from -0.14°F to 1.49°F. The maximum temperature increase was 1.01°F on average and ranged from 0.23°F to 2.39°F. This sort of variation is well within the range of temperatures reported in Idaho Power’s program information.

Appendix

June 21 Curtailment:

Event Details:
Time: 4-7pm
Notes: Devices were programmed to run the smart algorithm for this event
Curtailment: 65%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	95	0.47	0.51	0.78	0.92
Boise Metro (DRU)	95	N/A	N/A	1.29	1.38
Boise Metro (LCT)	95	N/A	N/A	0.72	0.85
TF/Pocatello	89	0.40	0.44	0.51	0.60
All	95	0.46	0.50	N/A	N/A

Figure 35. June 21 Curtailment Results: AMI – Both Regions

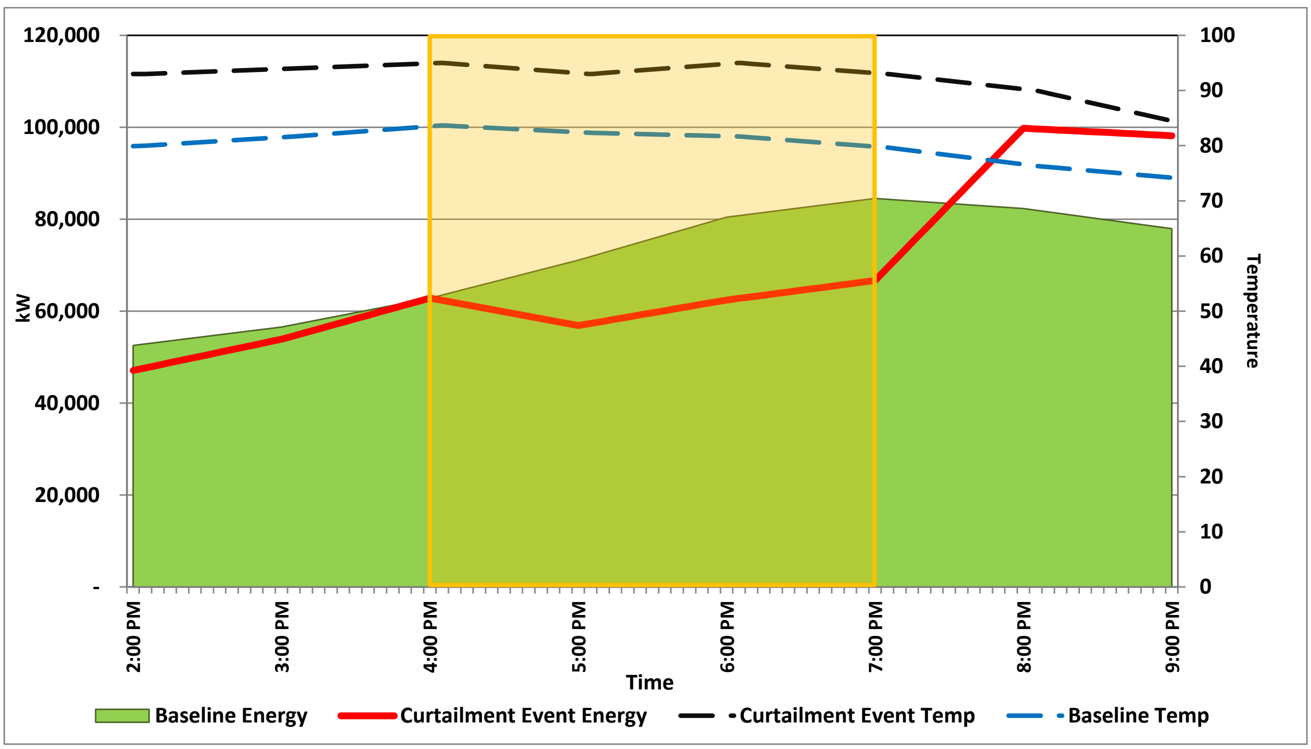


Figure 36. June 21 Curtailment Results: AMI – Boise Metro Region

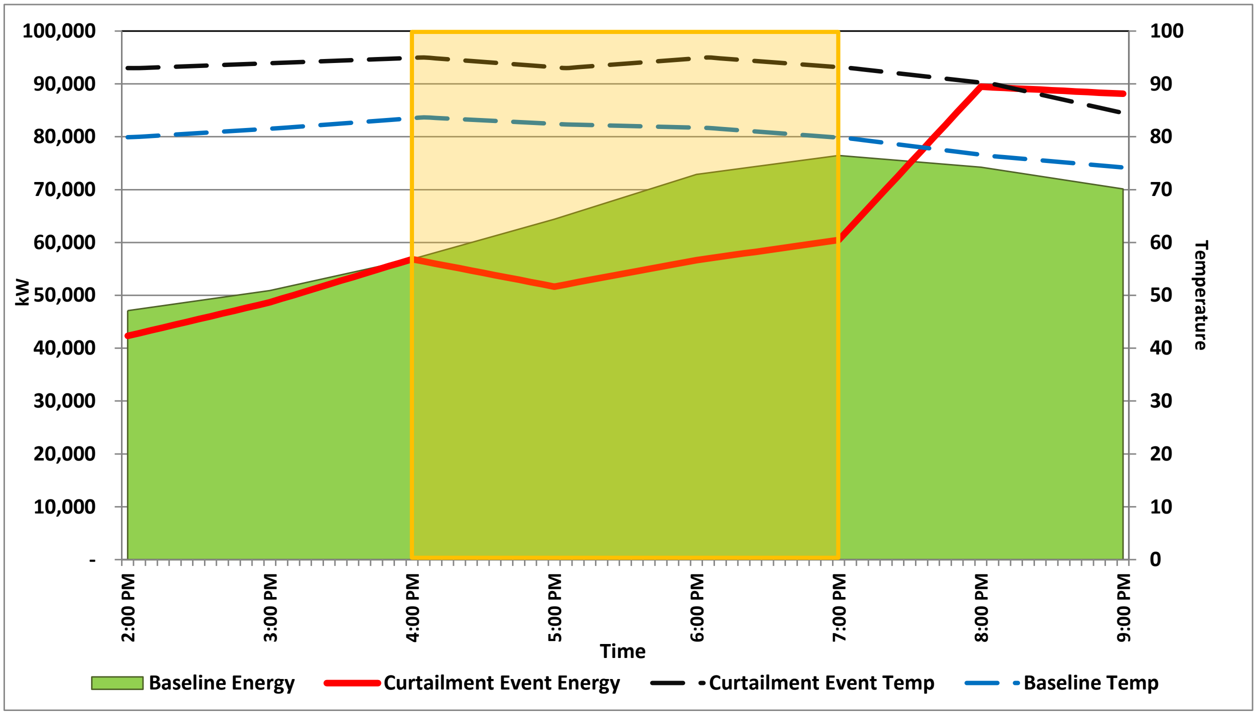


Figure 37. June 21 Curtailment Results: AMI – Twin Falls / Pocatello Region

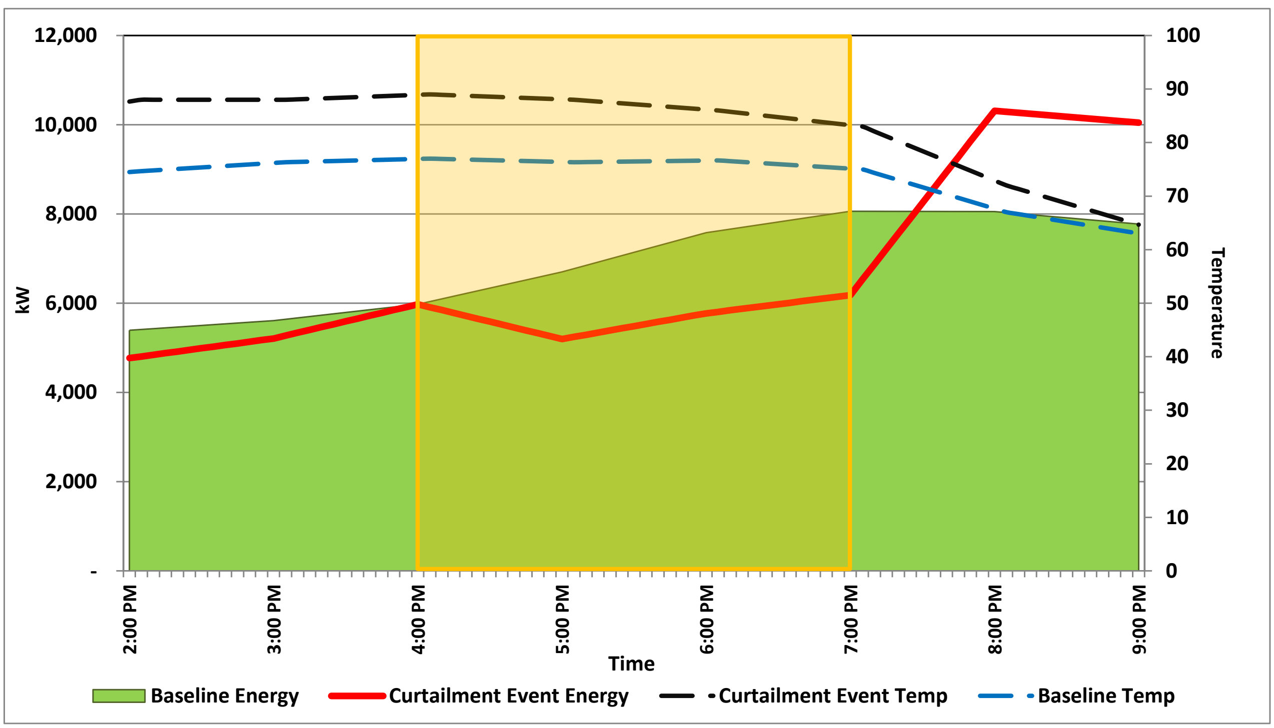


Figure 38. June 21 Curtailment Results: Loggers – Boise Metro Region

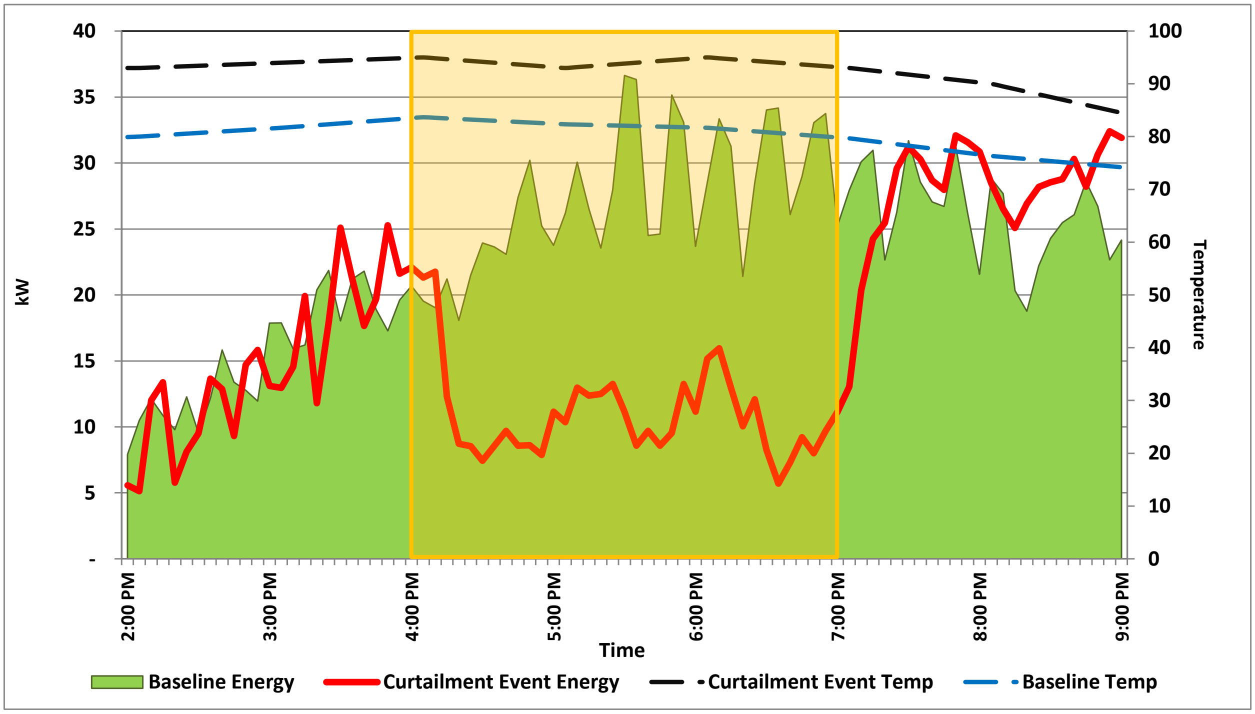


Figure 39. June 21 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

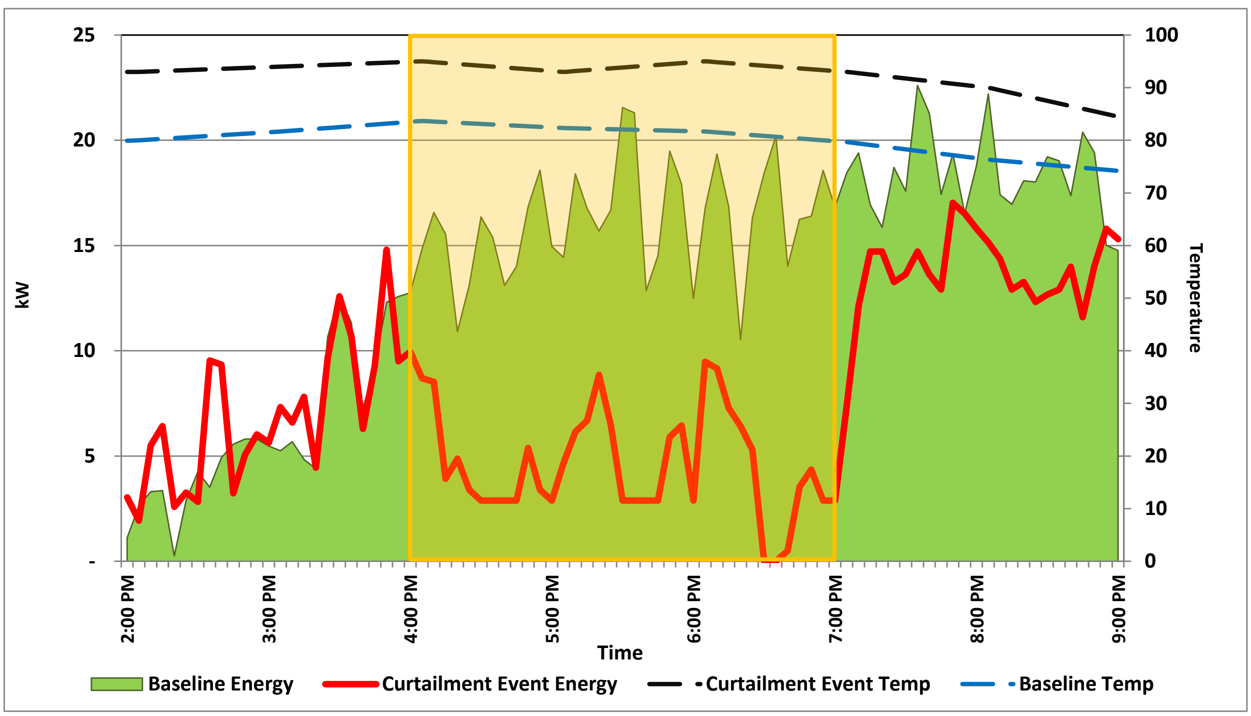


Figure 40. June 21 Curtailment Results: Loggers – Boise Metro Region (LCT Only)

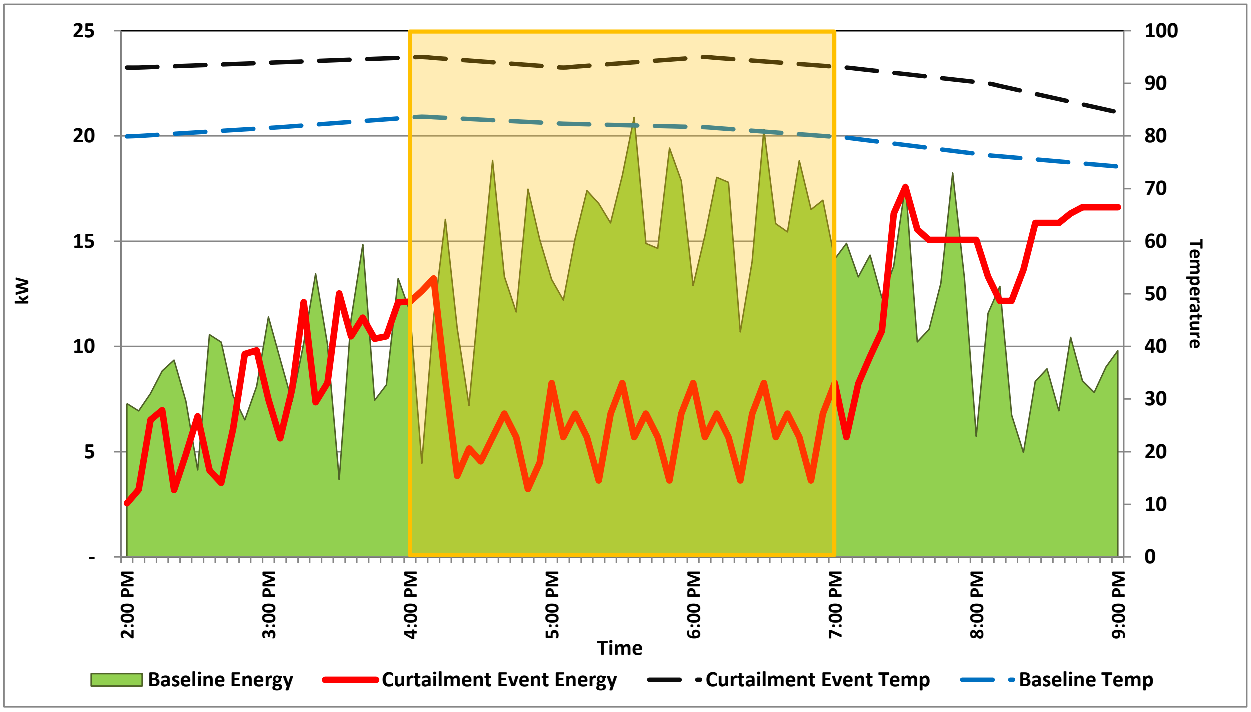
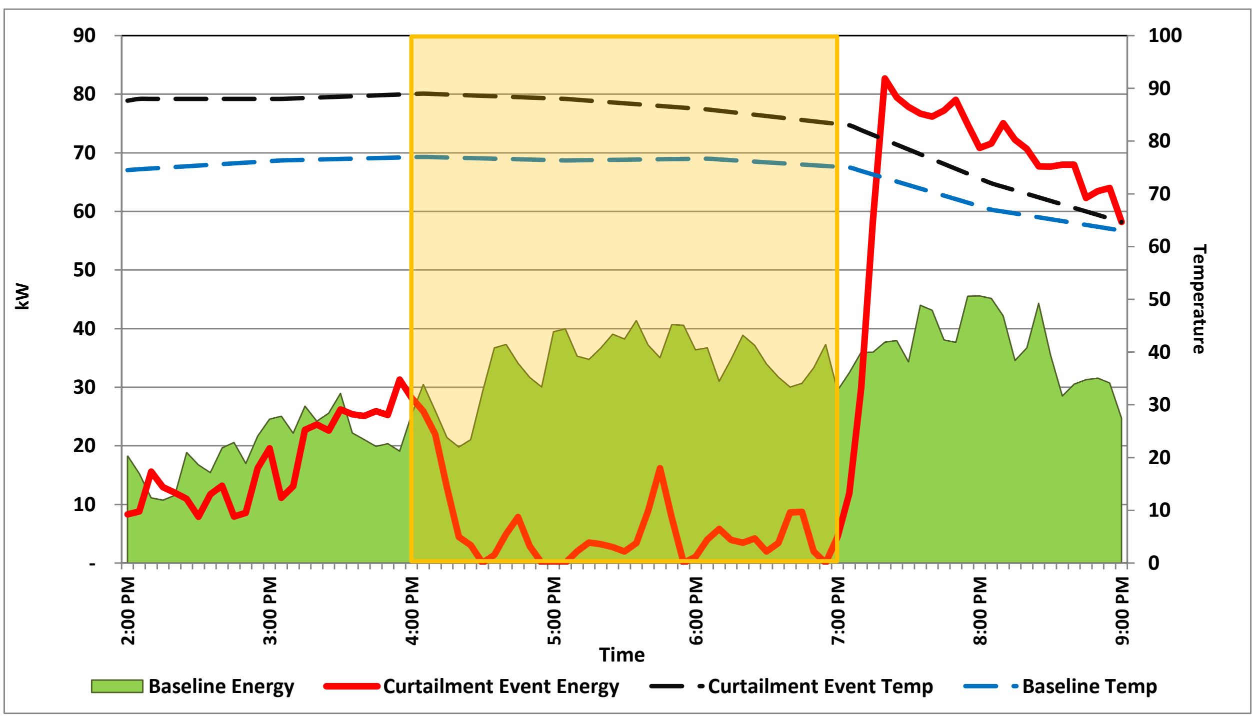


Figure 41. June 21 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 2 Curtailment

Event Details:
Time: 5-6 pm
Notes: LCTs only
Curtailment: 100%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	95	0.28	0.28	0.4	0.40
TF/Pocatello	89	0.02	0.02	-0.01	-0.01
All	95	0.25	0.25	N/A	N/A

Figure 42. July 2 Curtailment Results: AMI – Both Regions

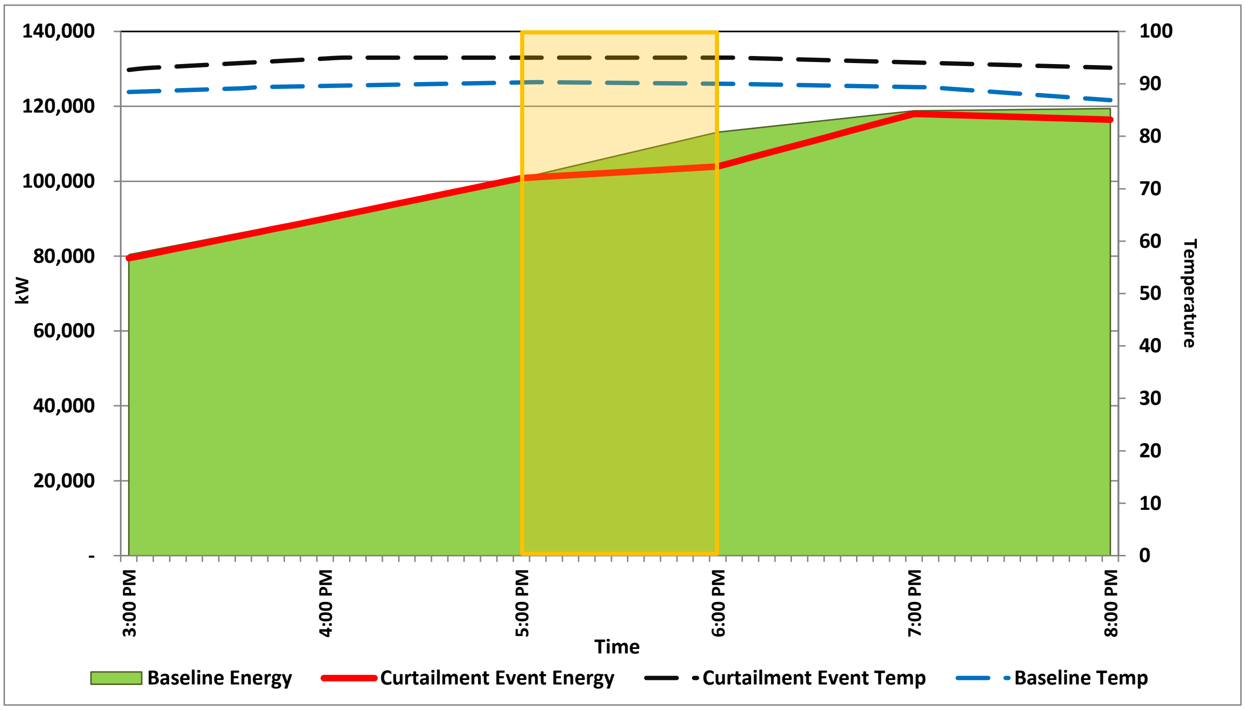


Figure 43. July 2 Curtailment Results: AMI – Boise Metro Region

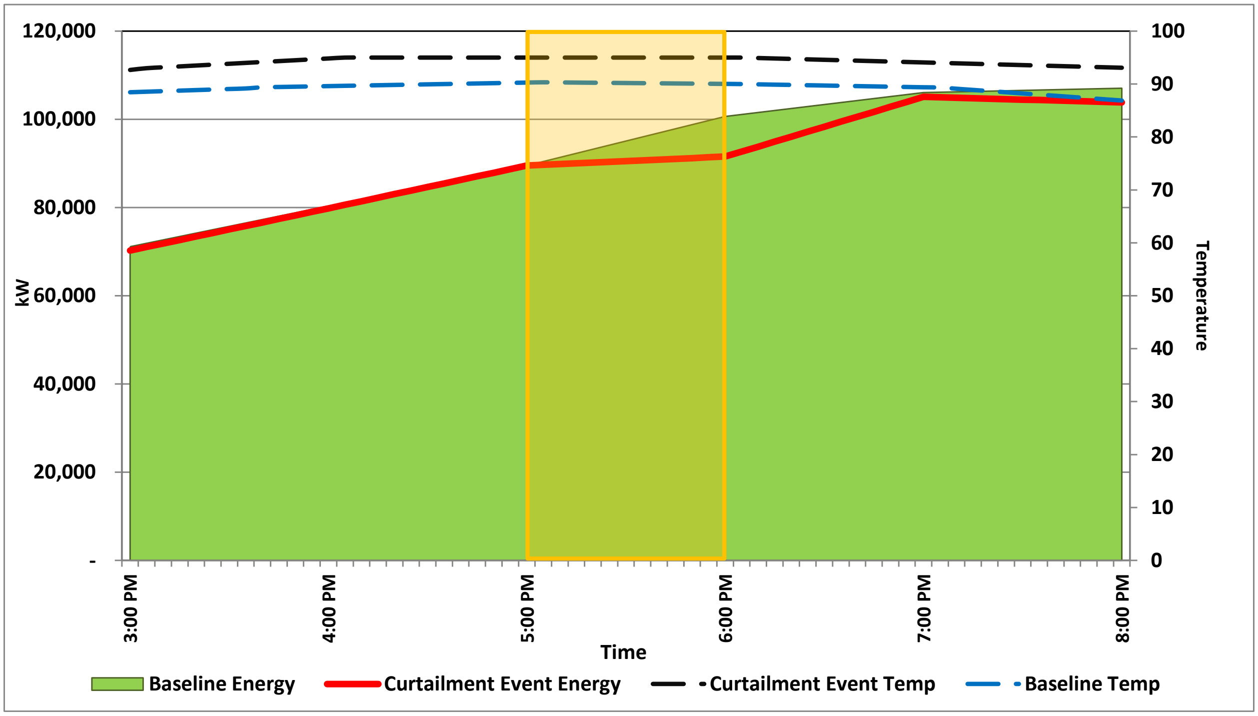


Figure 44. July 2 Curtailment Results: AMI – Twin Falls / Pocatello Region

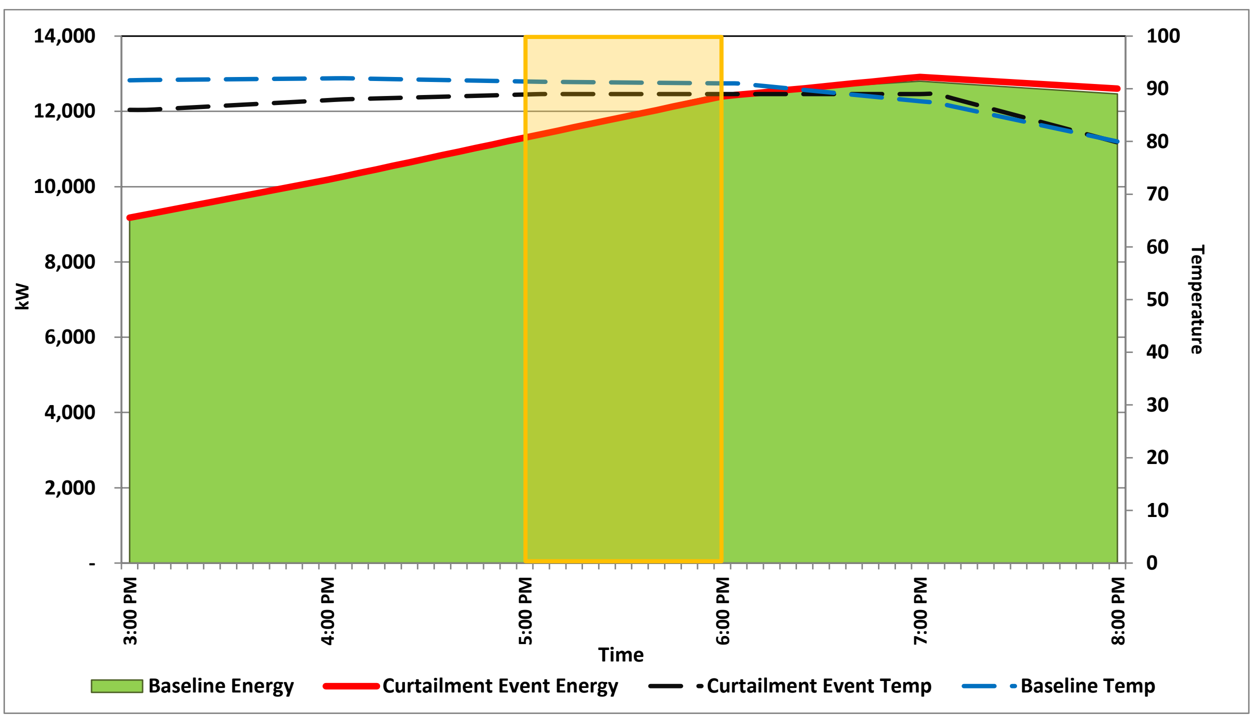


Figure 45. July 2 Curtailment Results: Loggers – Boise Metro Region

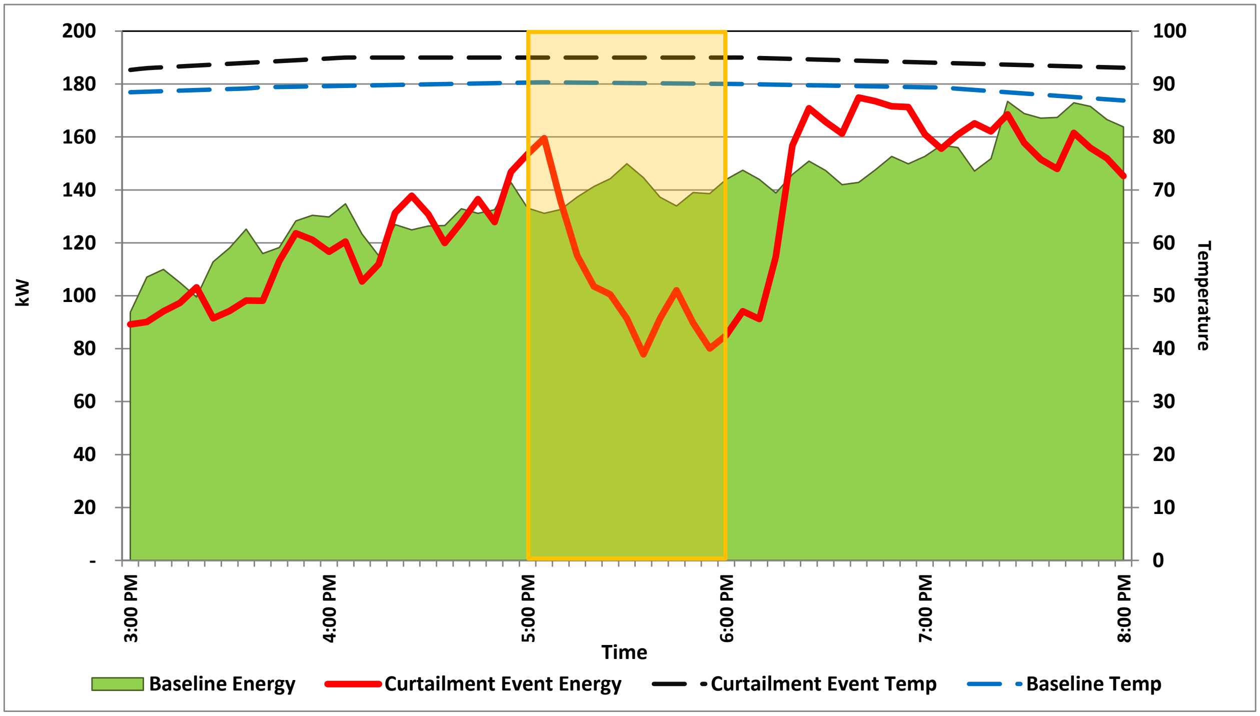
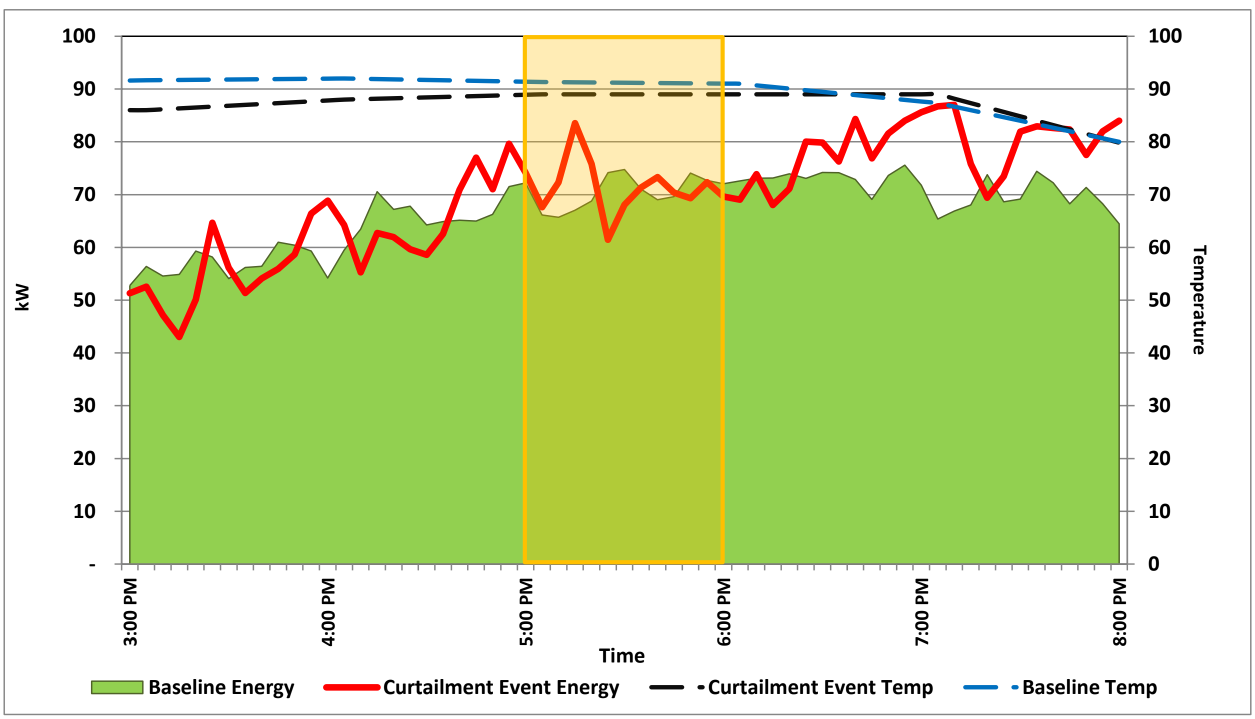


Figure 46. July 2 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 11 Curtailment

Event Details:
Time: 4-8 pm
Notes: LCRs curtailed from 4-7, LCTs/DRUs curtailed from 5-8.
Curtailment: 60%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	99	0.21	0.44	0.09	0.21
TF/Pocatello	94	-0.49	-0.24	-0.26	-0.10
All	99	0.12	0.33	N/A	N/A

Figure 47. July 11 Curtailment Results: AMI – Both Regions

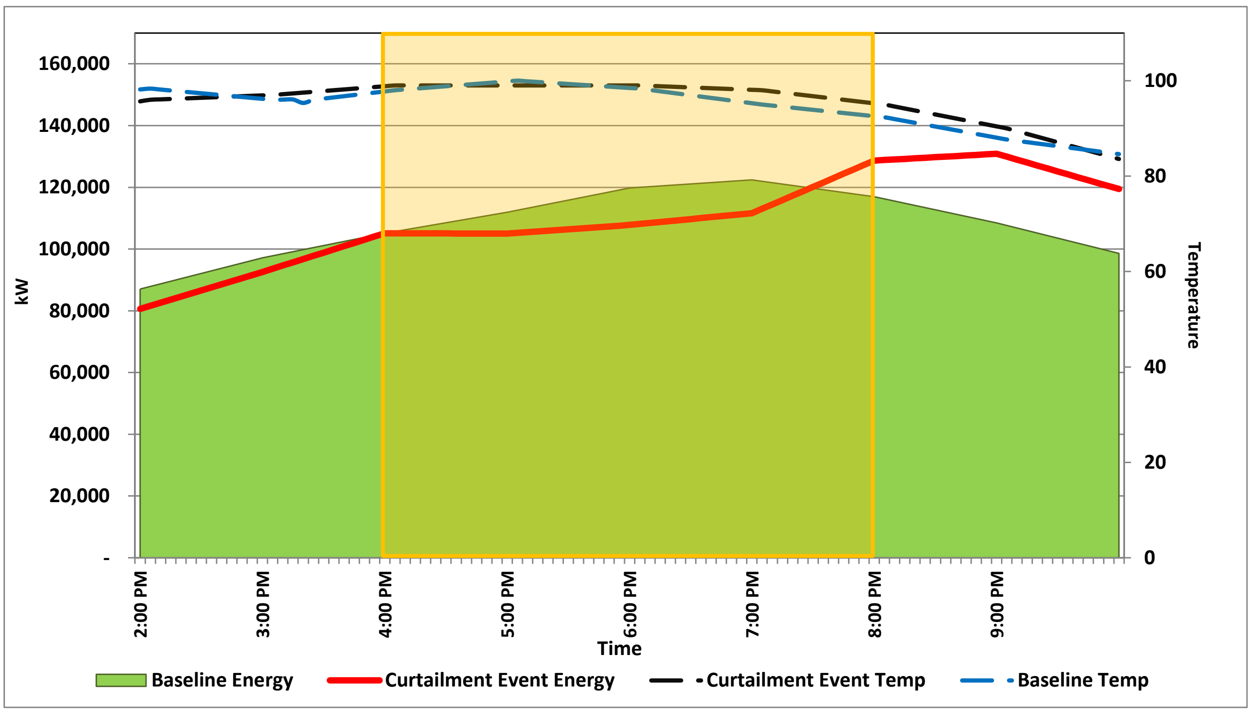


Figure 48. July 11 Curtailment Results: AMI – Boise Metro Region

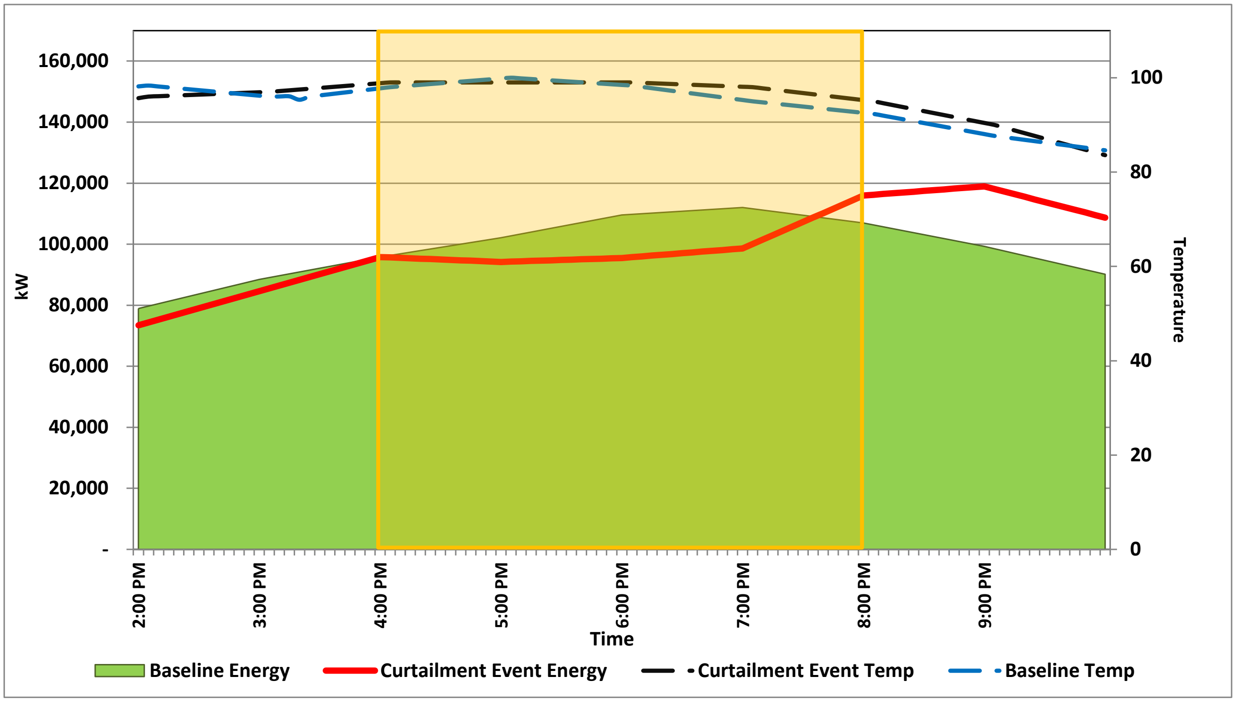


Figure 49. July 11 Curtailment Results: AMI – Twin Falls / Pocatello Region

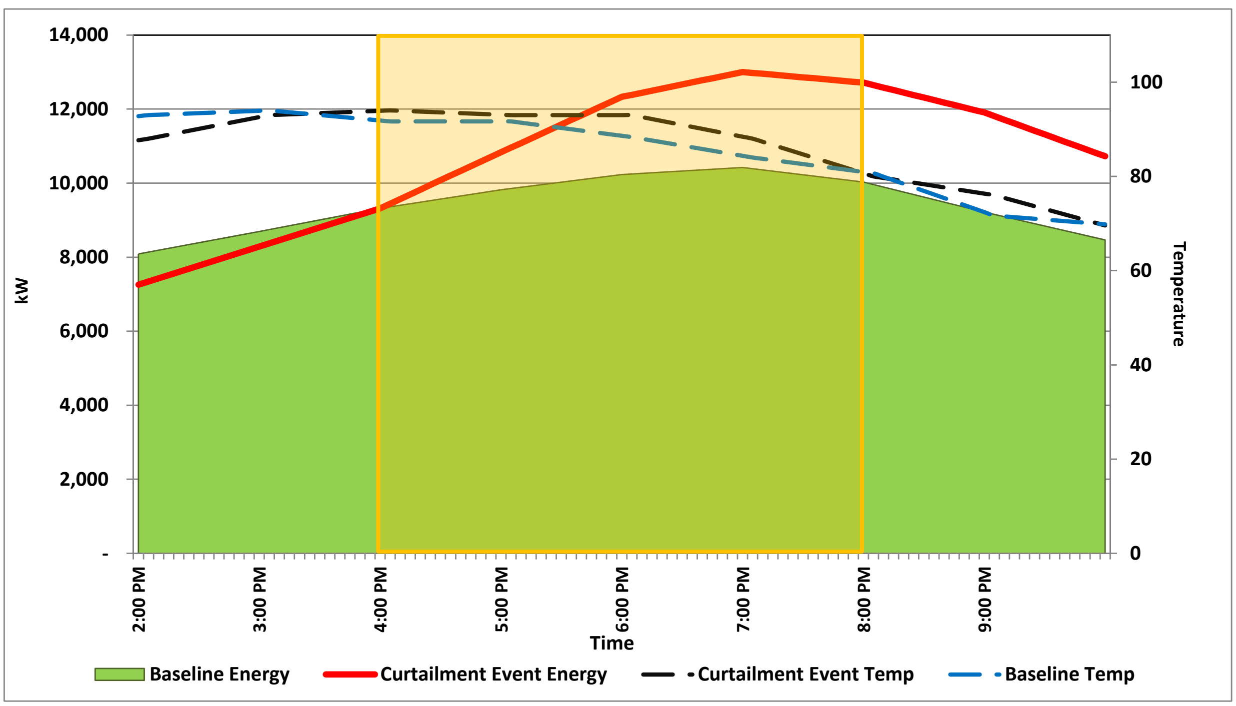


Figure 50. July 11 Curtailment Results: Loggers – Boise Metro Region

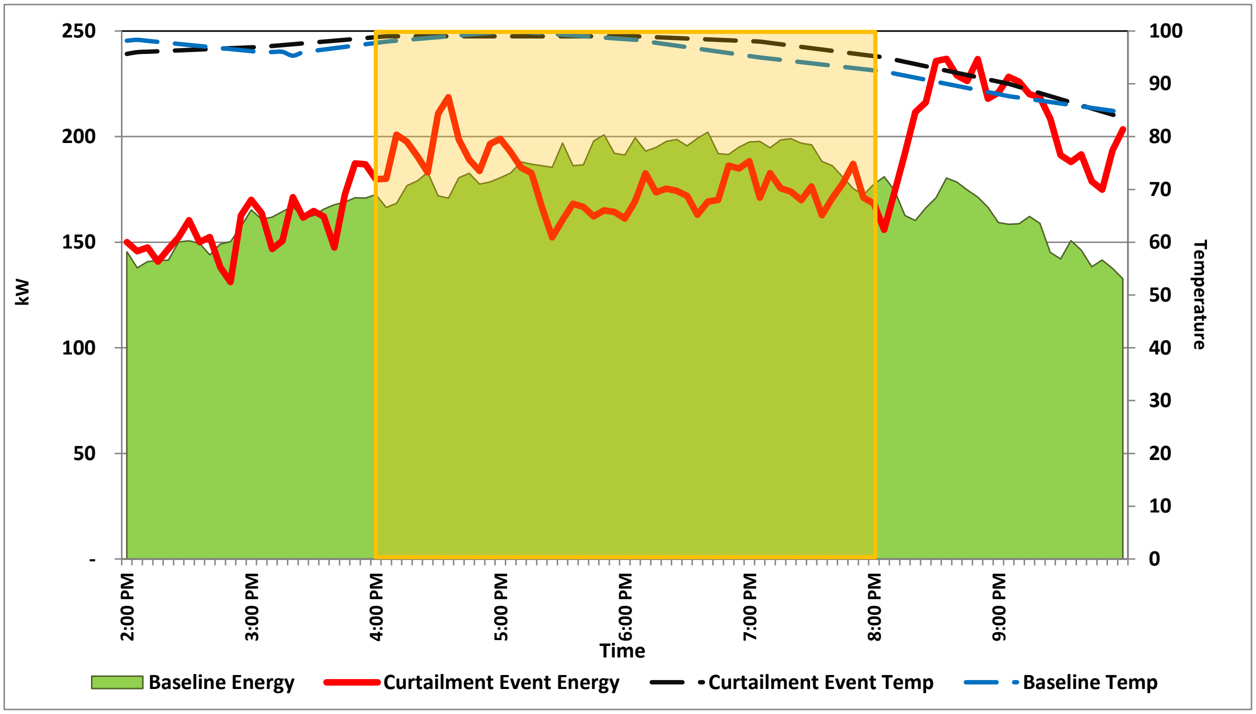


Figure 51. July 11 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

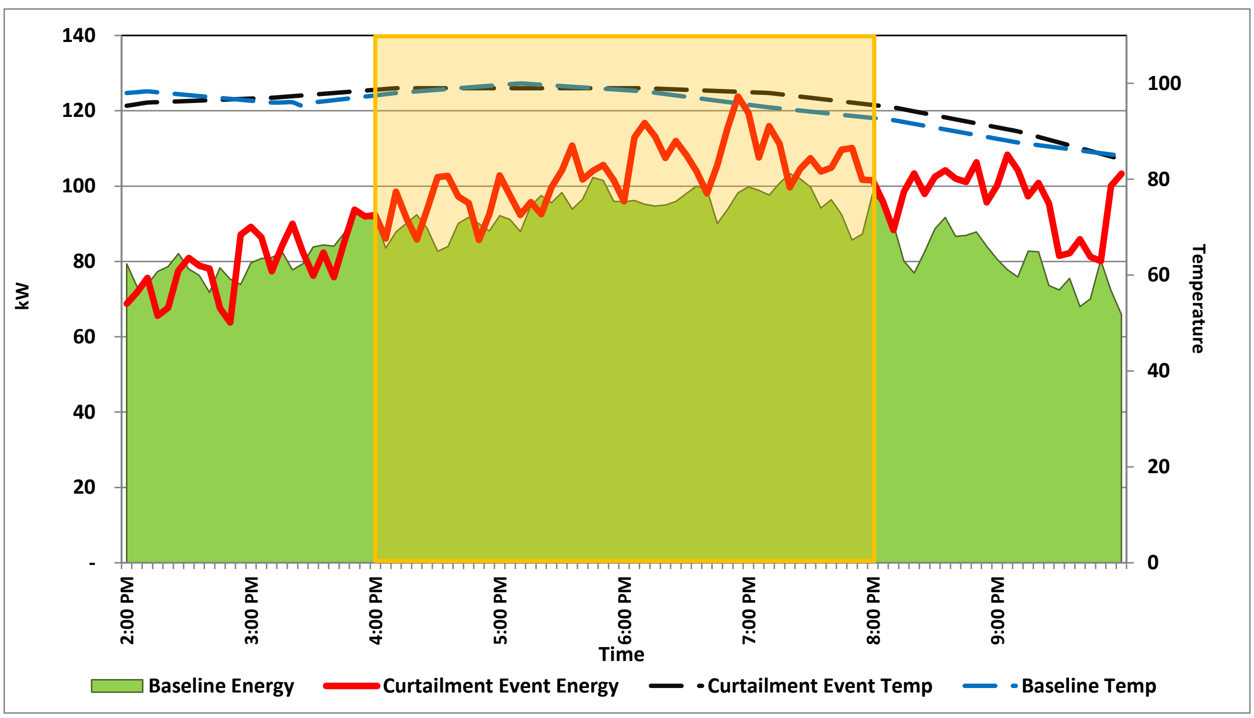


Figure 52. July 11 Curtailment Results: Loggers – Boise Metro Region (LCT Only)

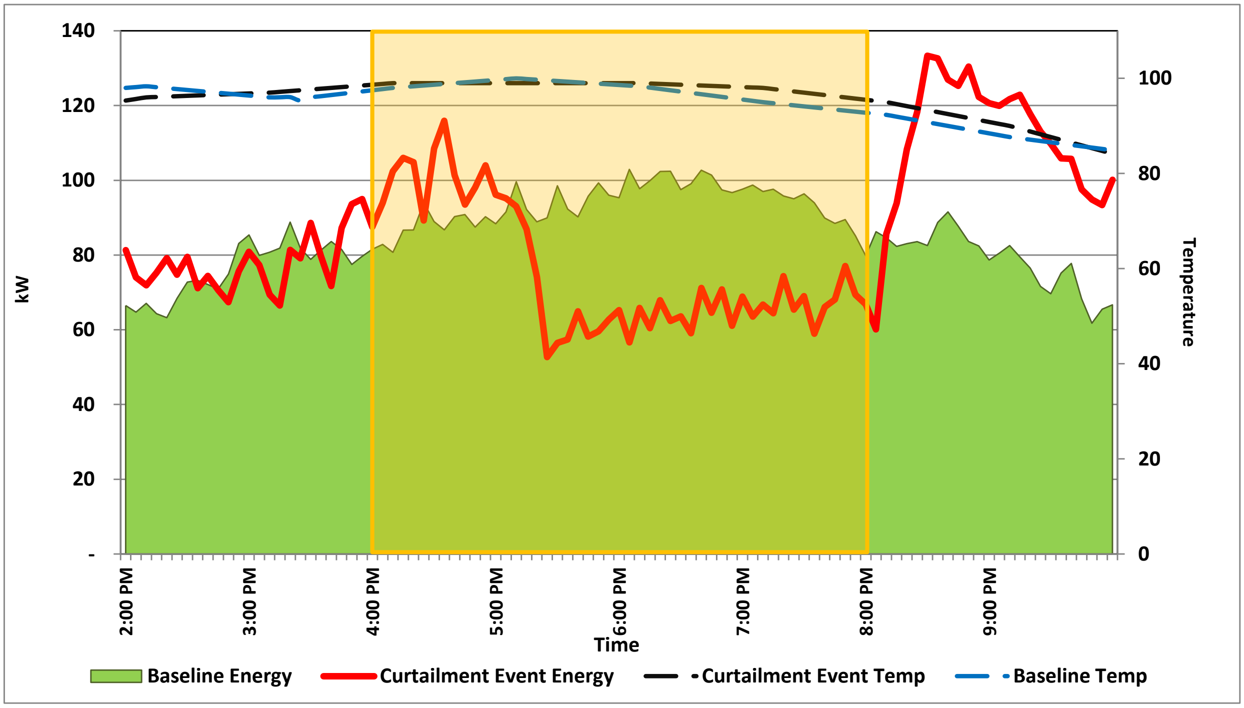
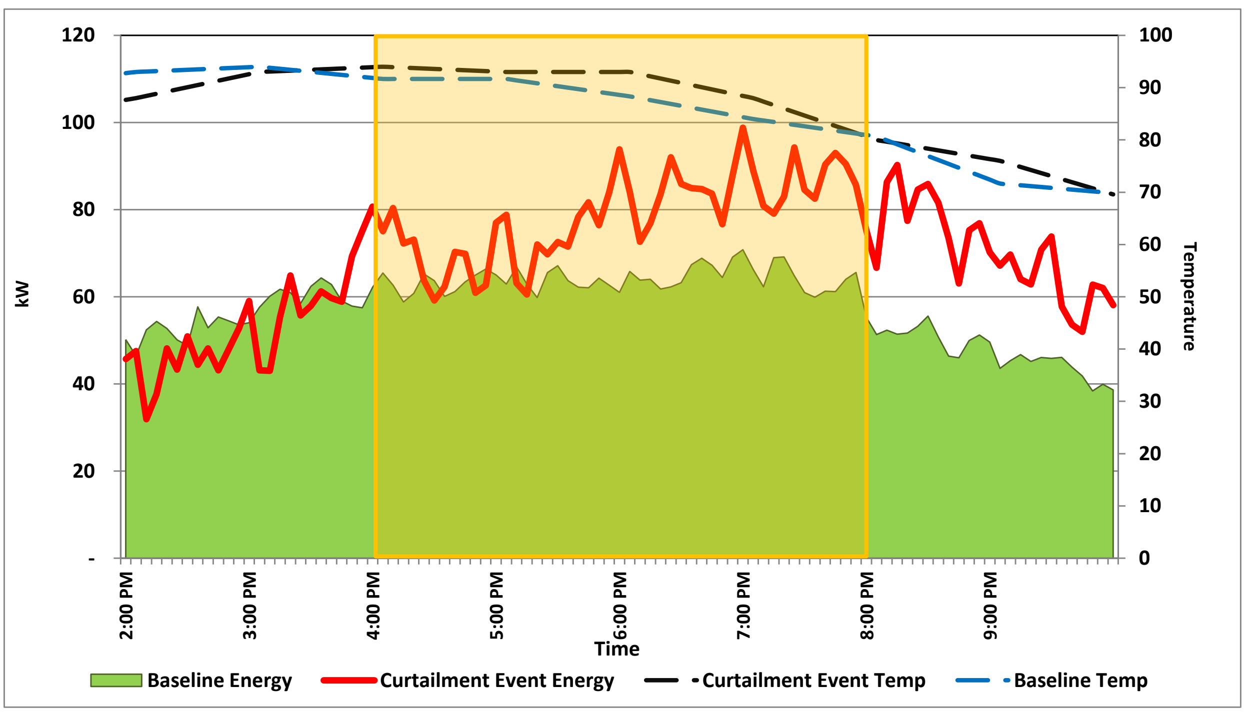


Figure 53. July 11 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 12 Curtailment

Event Details:
Time: 4-8 pm
Notes: LCRs curtailed from 4-7, LCTs/DRUs curtailed from 5-8.
Curtailment: 60%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	106	0.75	1.14	0.67	1.05
TF/Pocatello	99	0.45	0.69	0.38	0.70
All	106	0.71	1.09	N/A	N/A

Figure 54. July 12 Curtailment Results: AMI – Both Regions

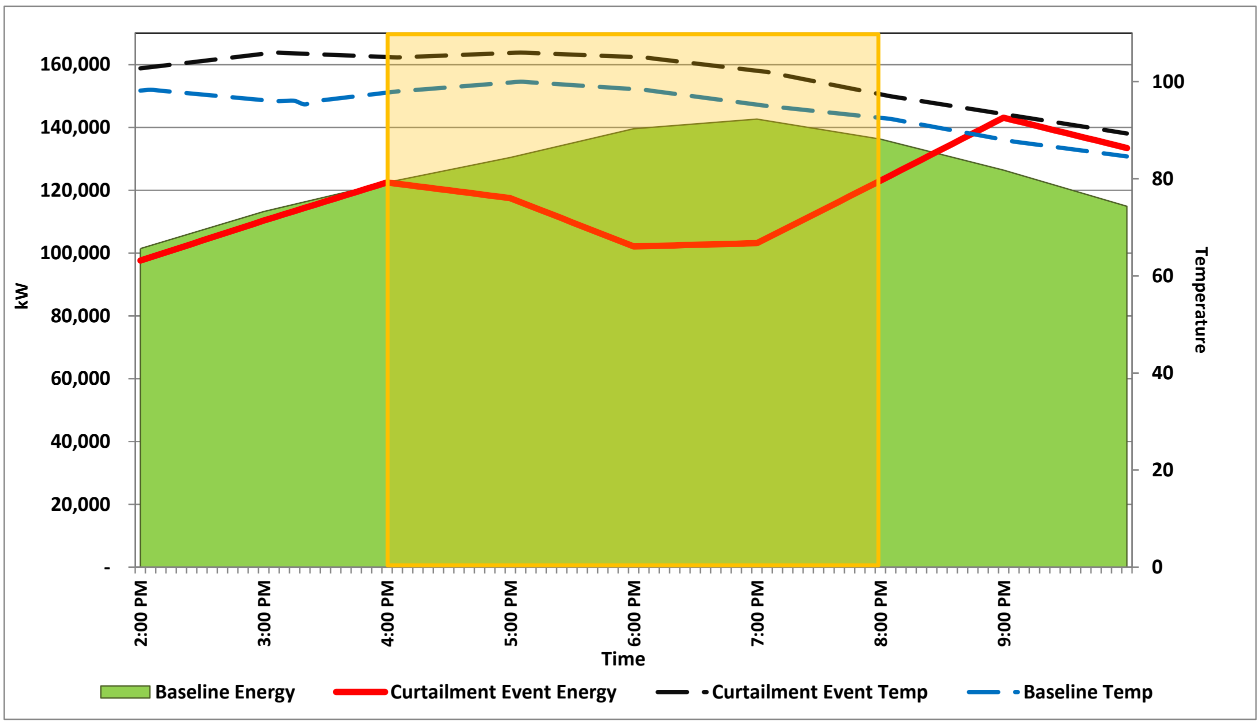


Figure 55. July 12 Curtailment Results: AMI – Boise Metro Region

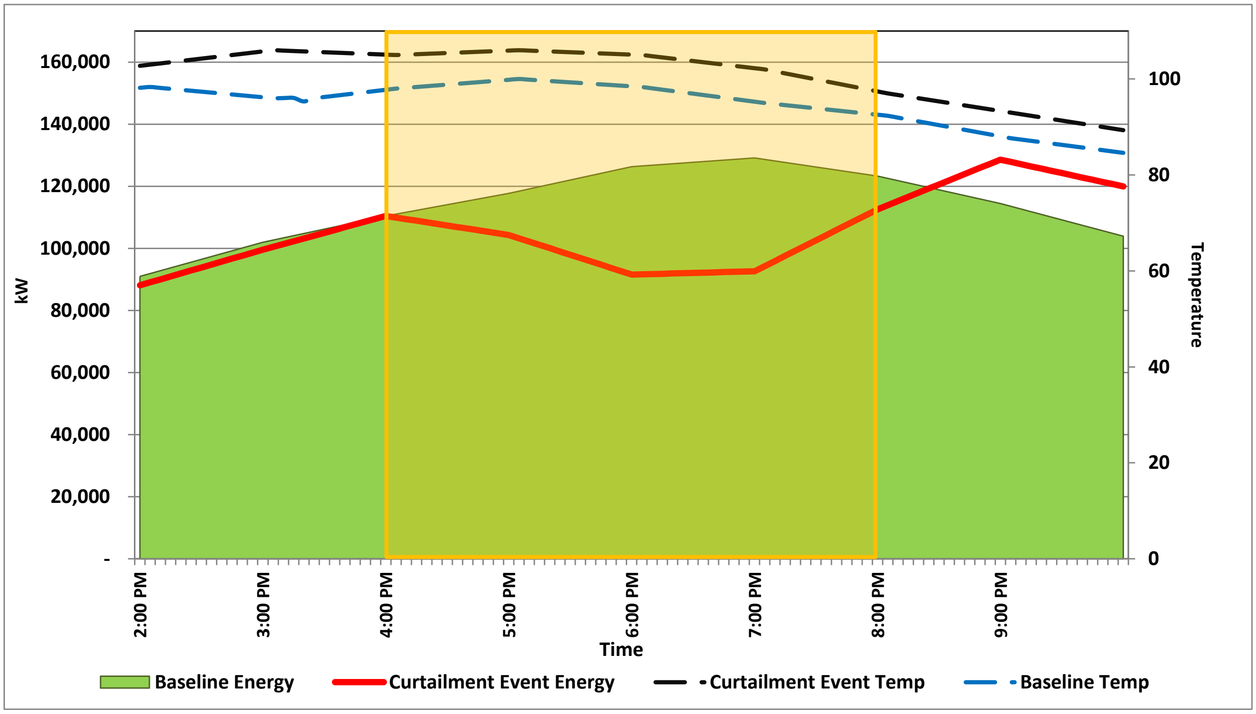


Figure 56. July 12 Curtailment Results: AMI – Twin Falls / Pocatello Region

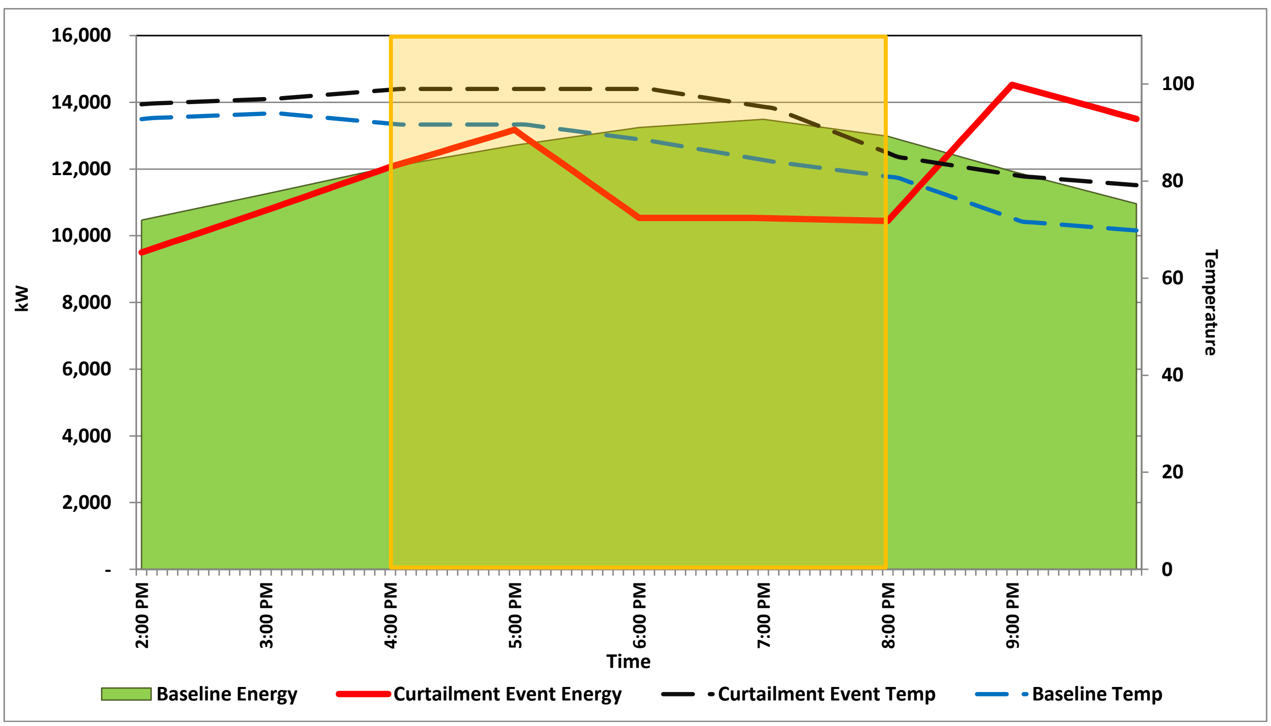


Figure 57. July 12 Curtailment Results: Loggers – Boise Metro Region

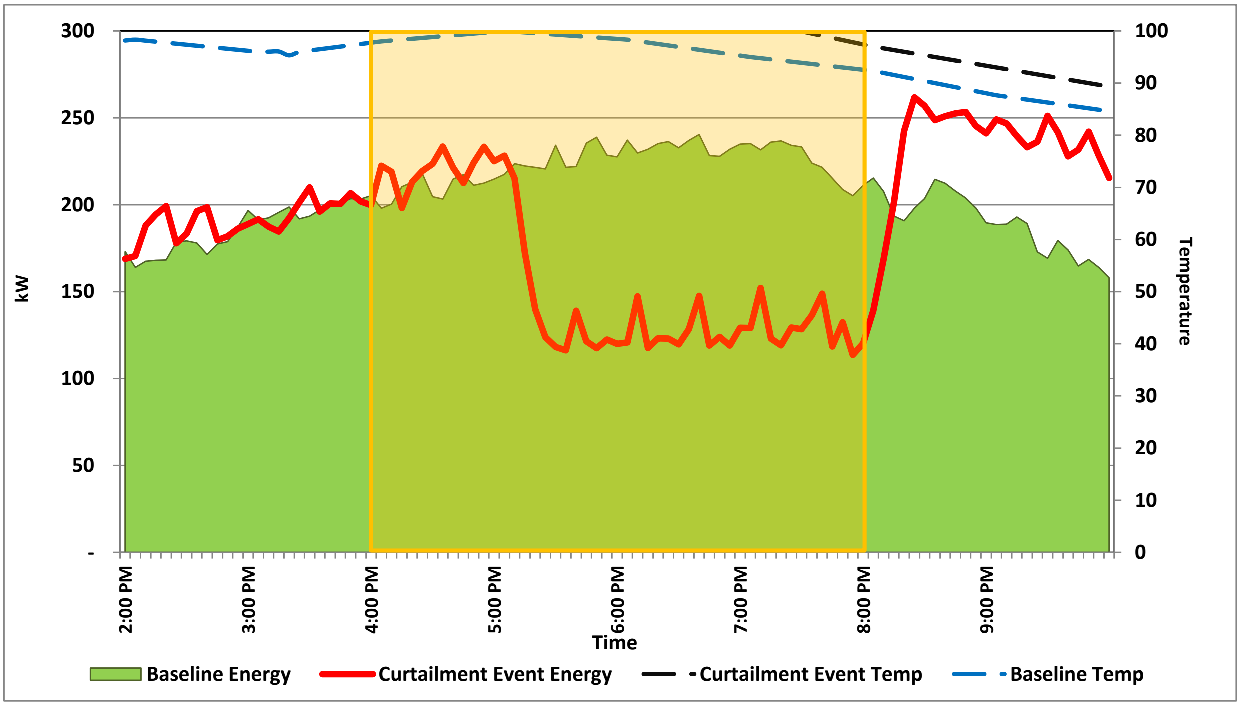
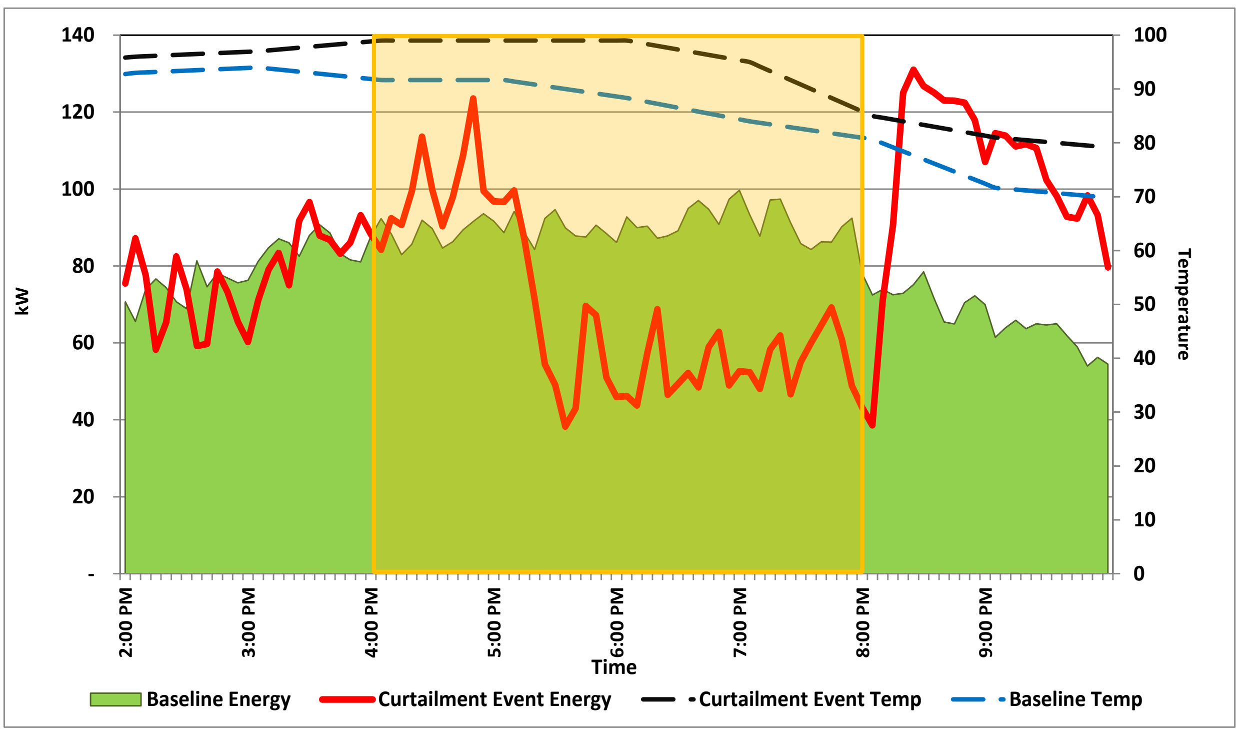


Figure 58. July 12 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 19 Curtailment

Event Details:
Time: 4-7 pm
Notes:
Curtailment: 65%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	104	0.92	0.99	0.80	0.89
TF/Pocatello	95	0.65	0.66	0.65	0.69
All	104	0.89	0.95	N/A	N/A

Figure 59. July 19 Curtailment Results: AMI – Both Regions

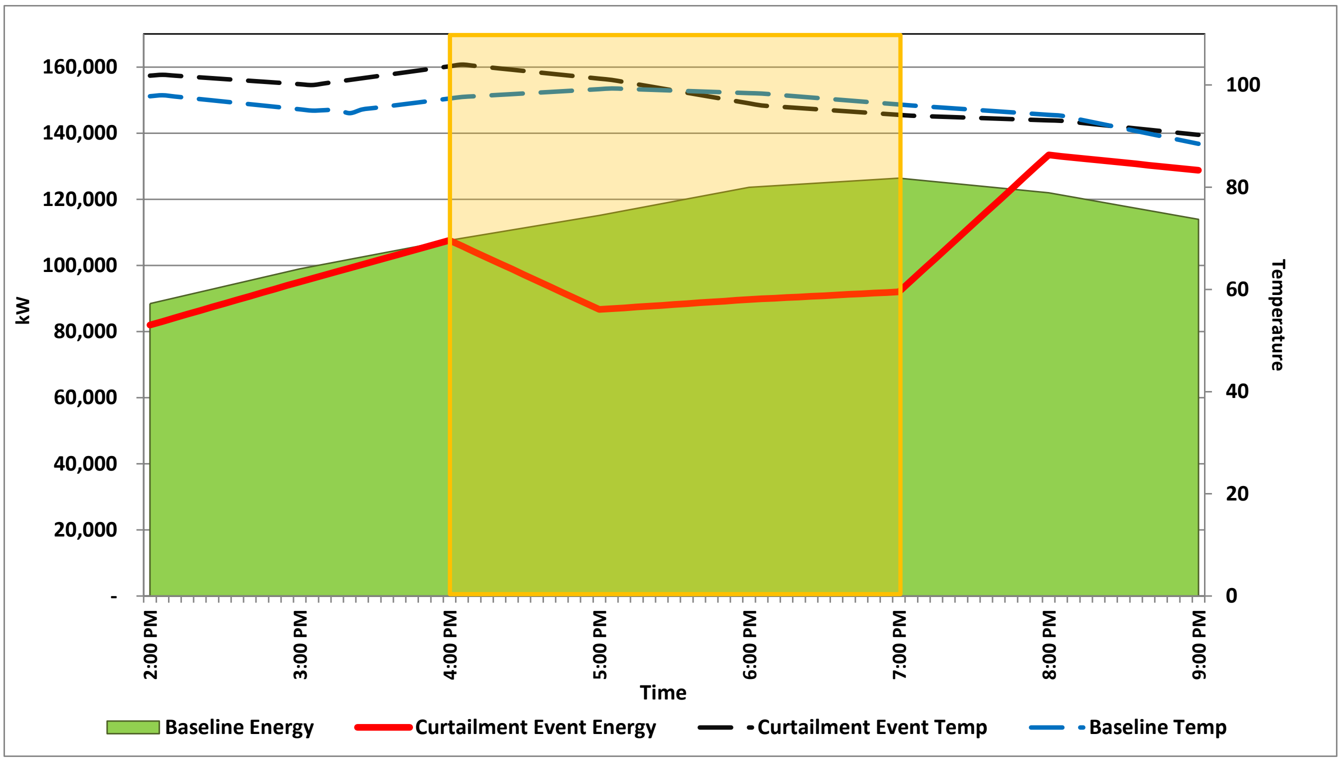


Figure 60. July 19 Curtailment Results: AMI – Boise Metro Region

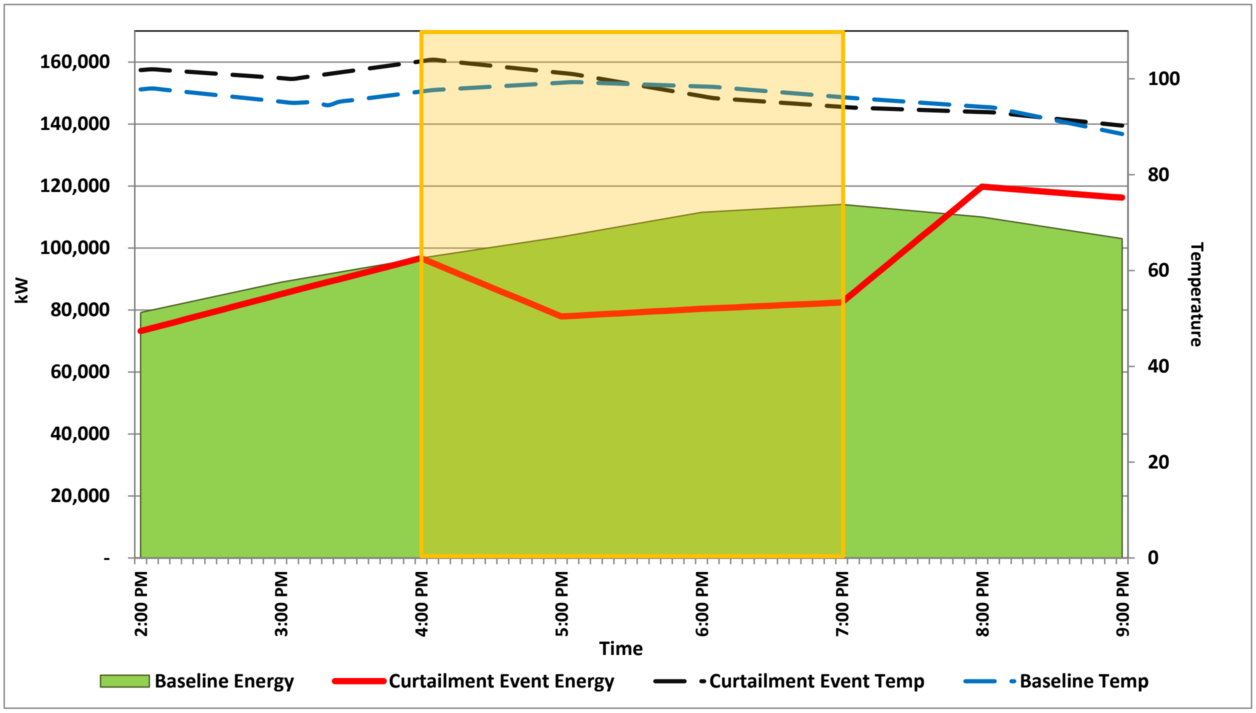


Figure 61. July 19 Curtailment Results: AMI – Twin Falls / Pocatello Region

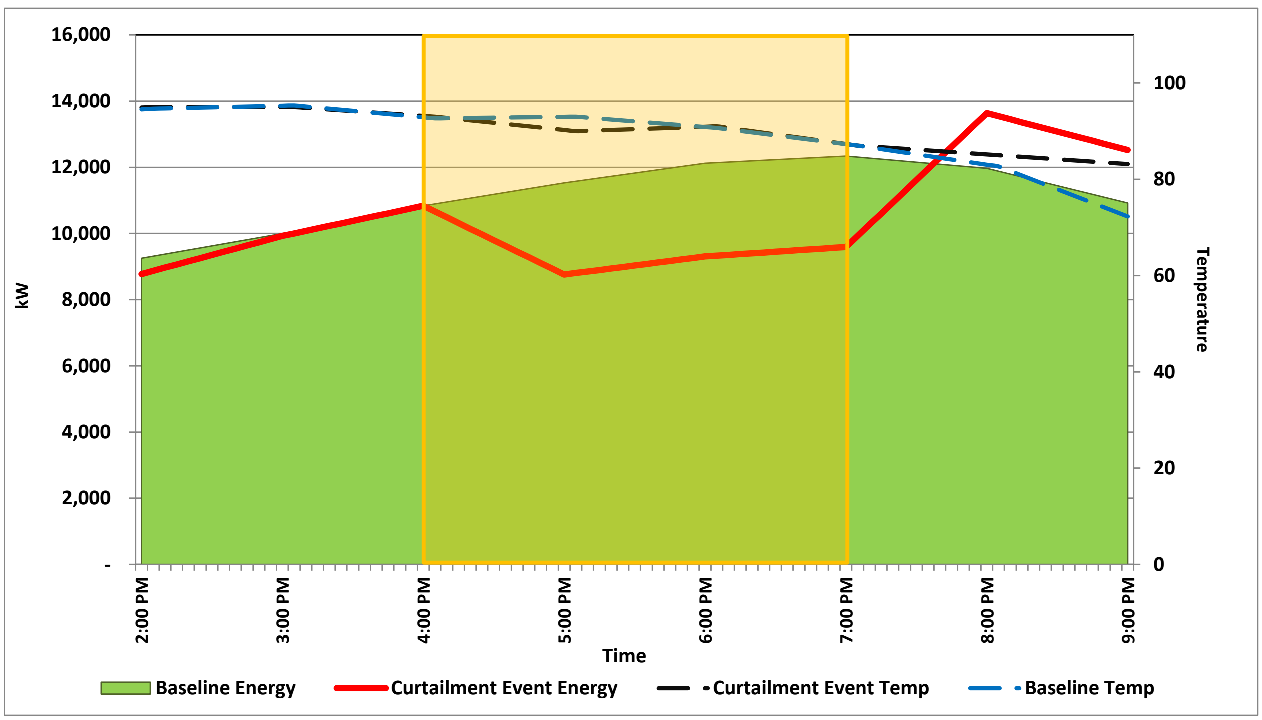


Figure 62. July 19 Curtailment Results: Loggers – Boise Metro Region

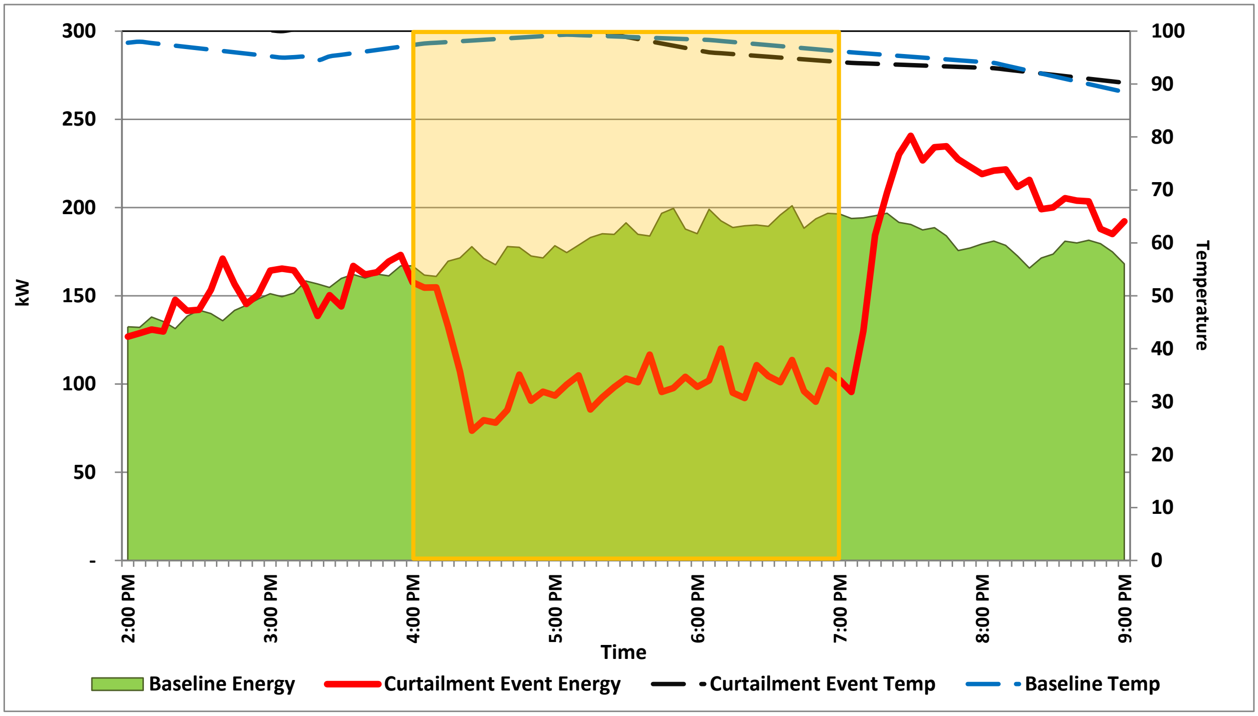
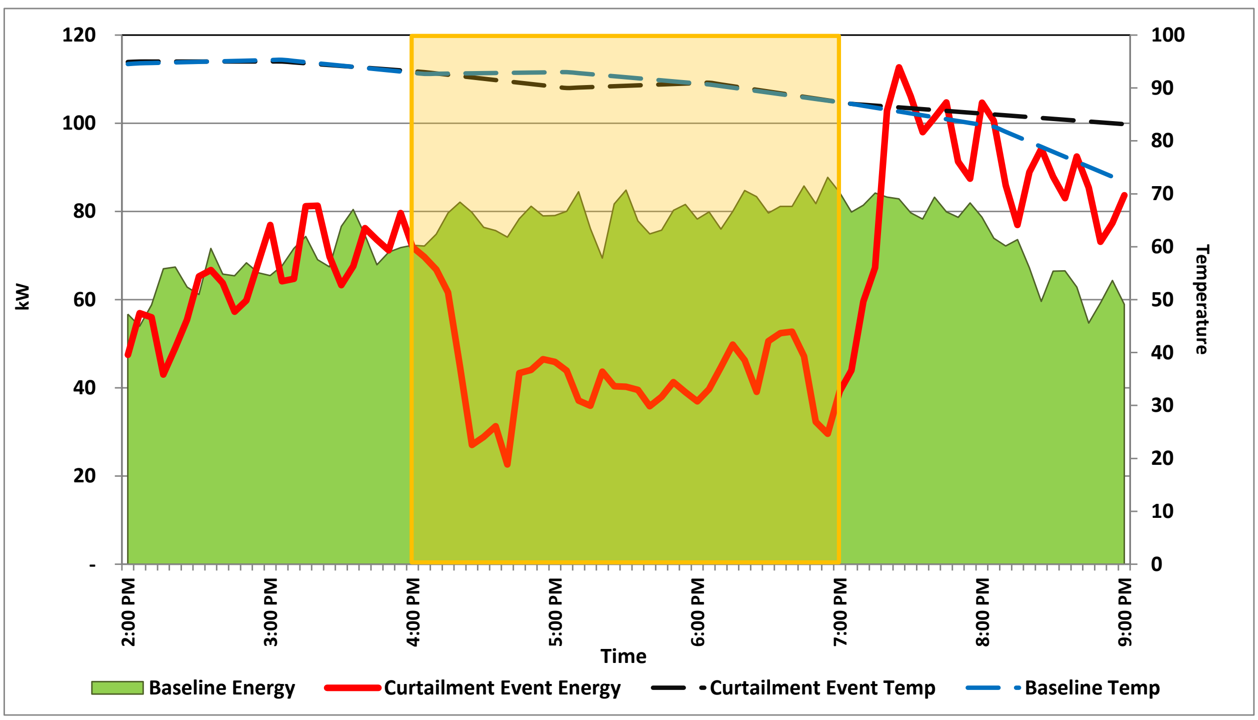


Figure 63. July 19 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 25 Curtailment

Event Details:
Time: 4-7 pm
Notes:
Curtailment: 50%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	97	0.31	0.35	0.24	0.34
TF/Pocatello	90	0.57	0.64	0.72	0.82
All	97	0.34	0.37	N/A	N/A

Figure 64. July 25 Curtailment Results: AMI – Both Regions

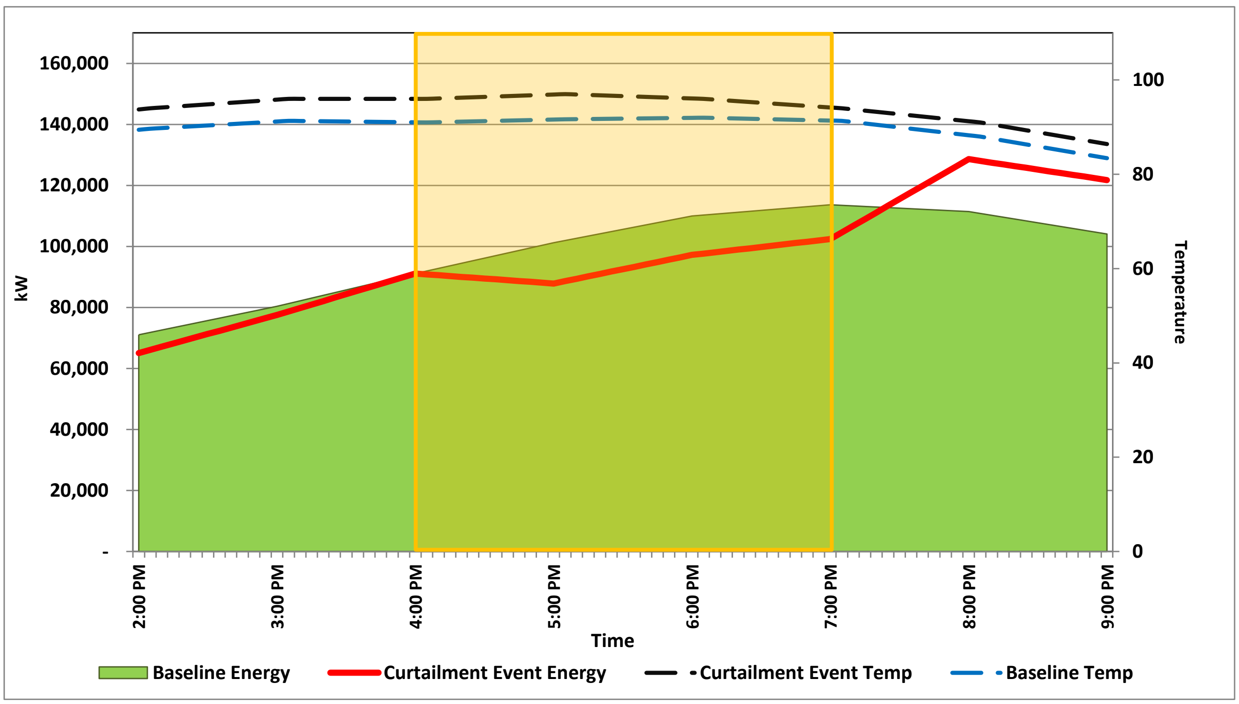


Figure 65. July 25 Curtailment Results: AMI – Boise Metro Region

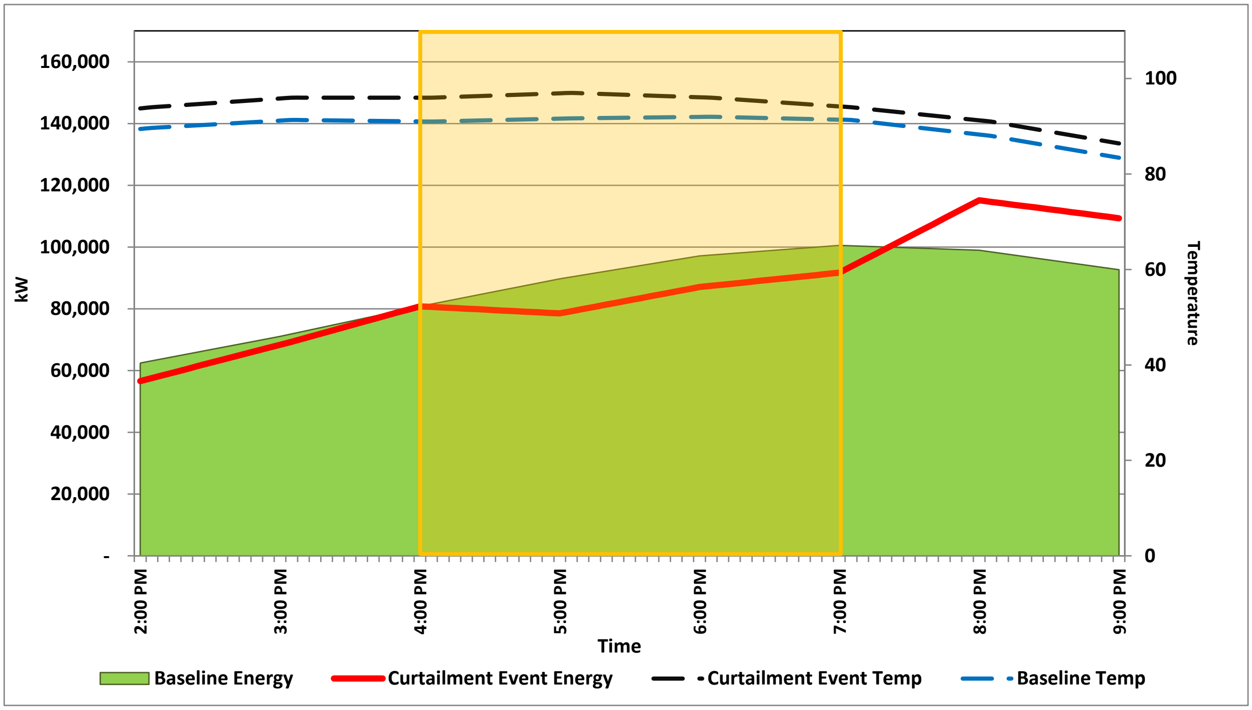


Figure 66. July 25 Curtailment Results: AMI – Twin Falls / Pocatello Region

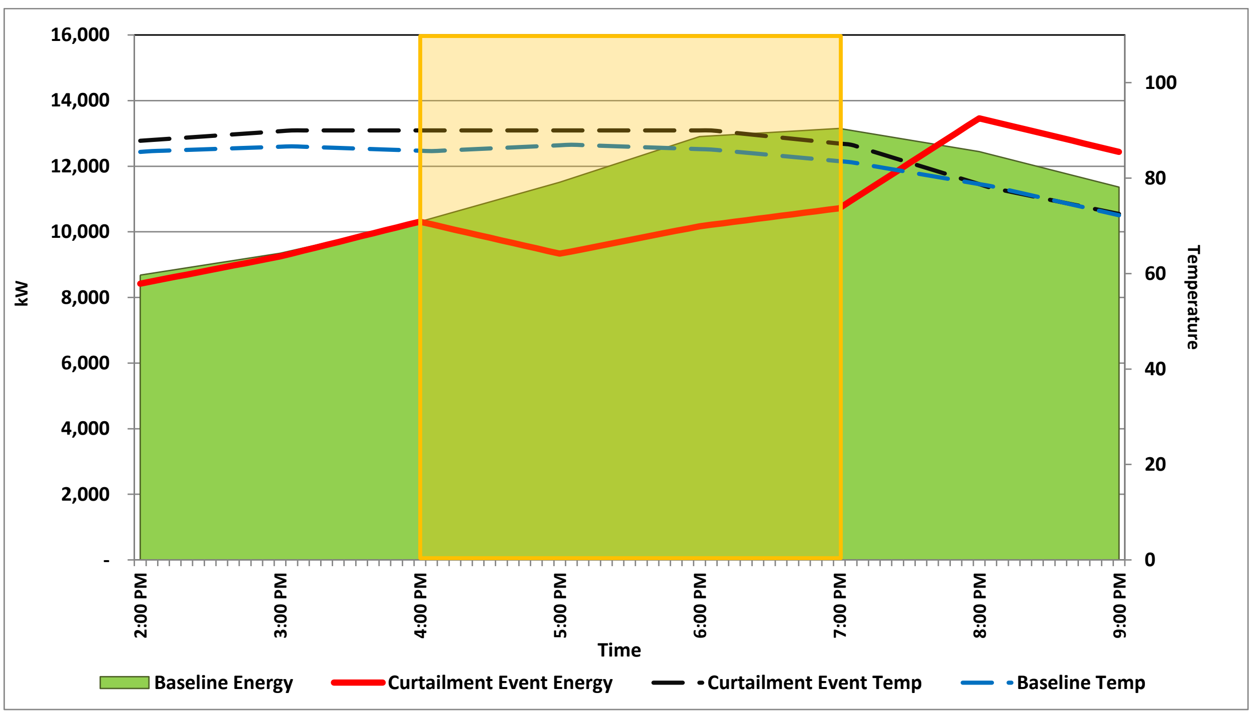


Figure 67. July 25 Curtailment Results: Loggers – Boise Metro Region

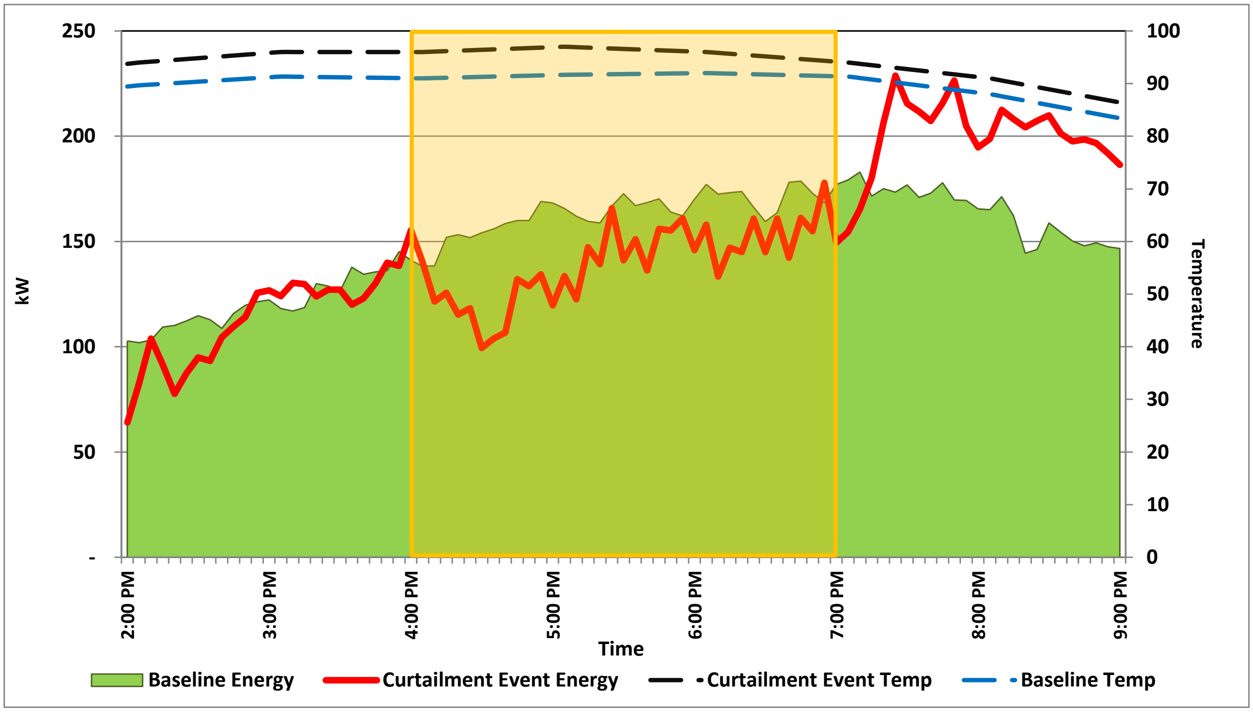


Figure 68. July 25 Curtailment Results: Loggers – Boise Metro Region (DRU Only)

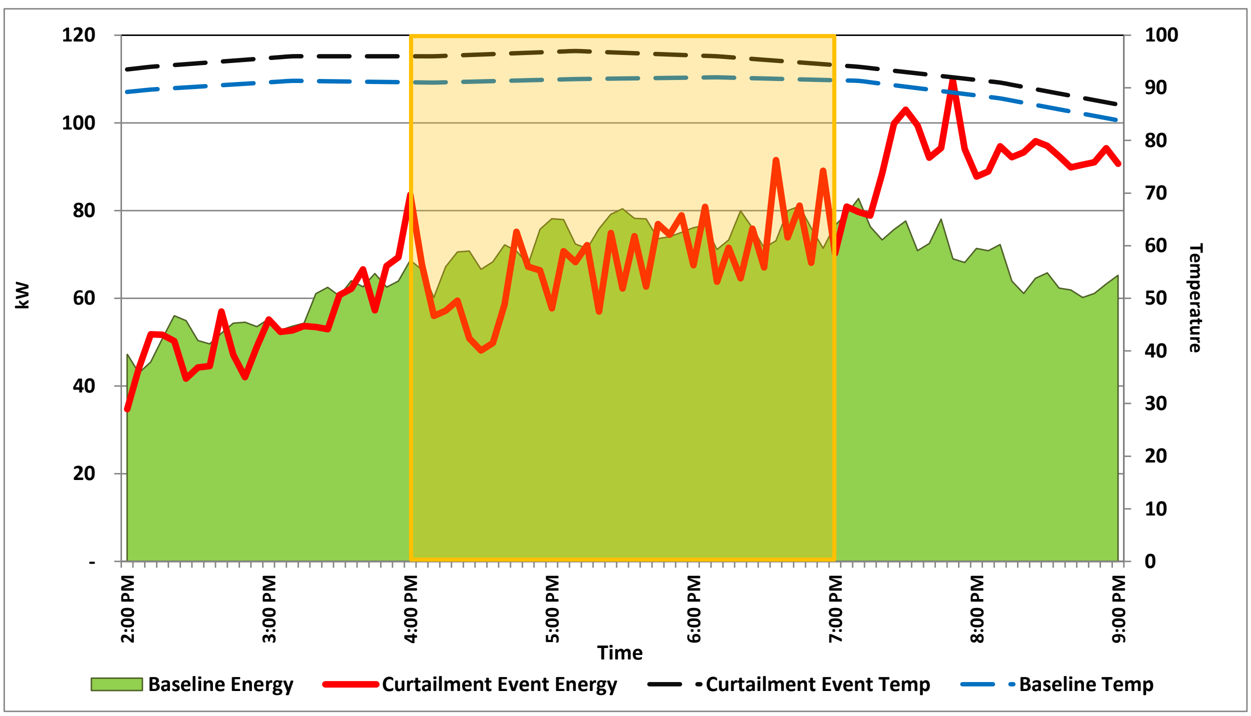


Figure 69. July 25 Curtailment Results: Loggers – Boise Metro Region (LCT Only)

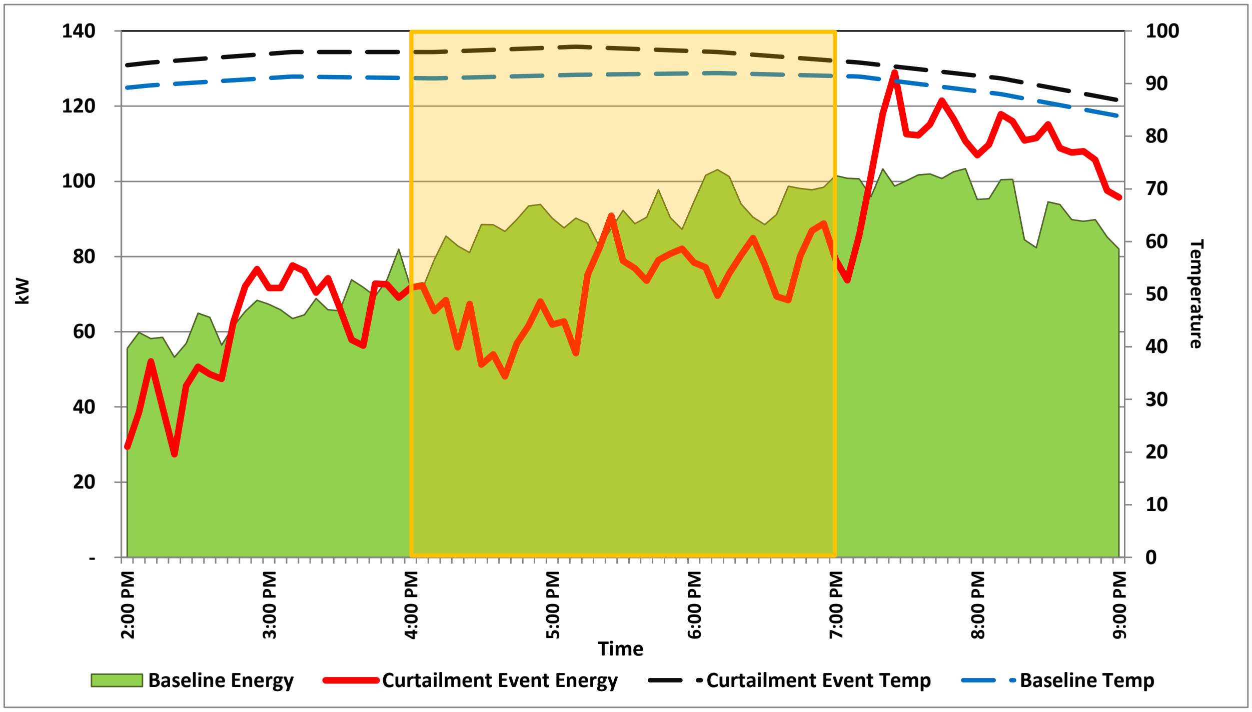
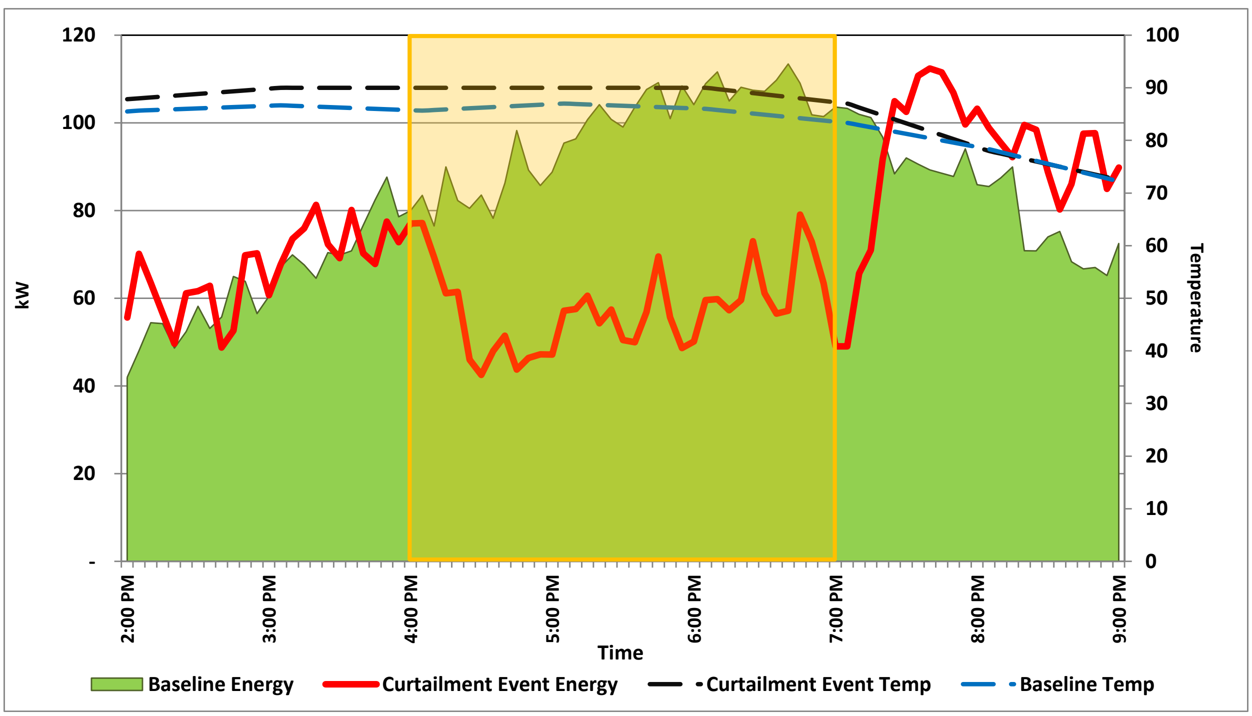


Figure 70. July 25 Curtailment Results: Loggers – Twin Falls / Pocatello Region



July 31 Curtailment

Event Details:
Time: 5-7 pm
Notes: Shortened time frame due to comfort concerns
Curtailment: 70%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	97	0.84	0.89	0.67	0.74
TF/Pocatello	94	0.83	0.90	0.98	1.12
All	97	0.84	0.89	N/A	N/A

Figure 71. July 31 Curtailment Results: AMI – Both Regions

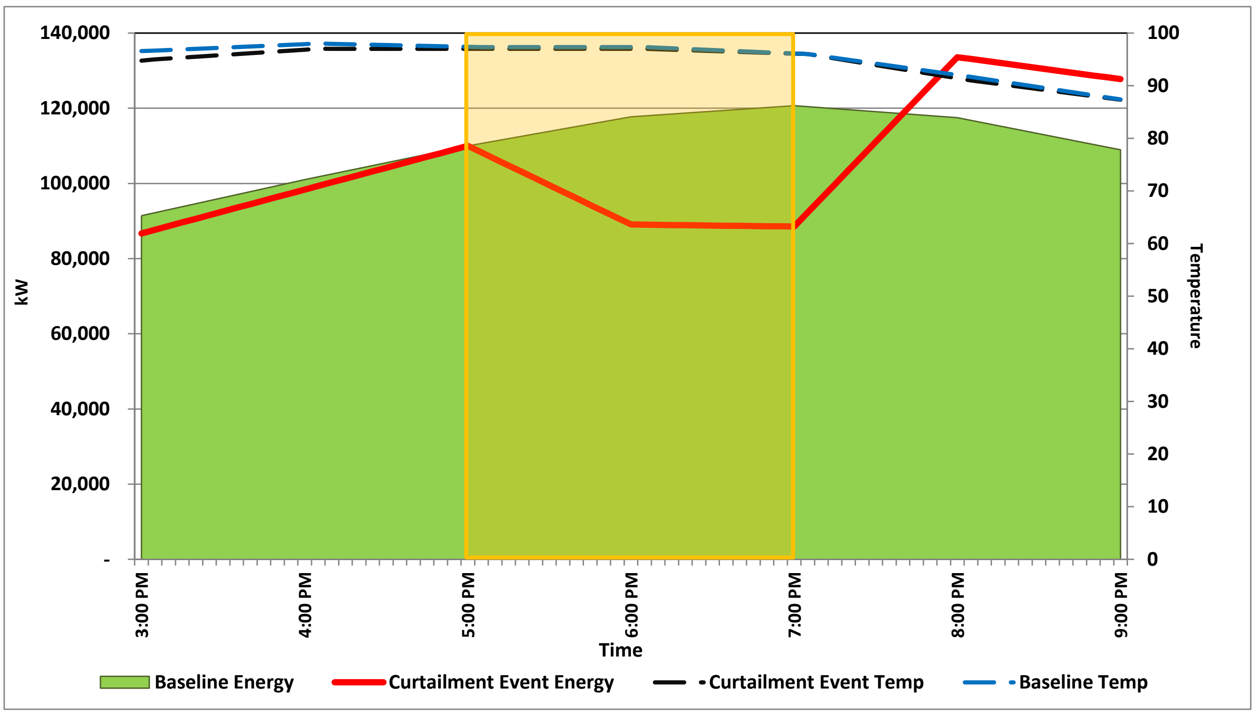


Figure 72. July 31 Curtailment Results: AMI – Boise Metro Region

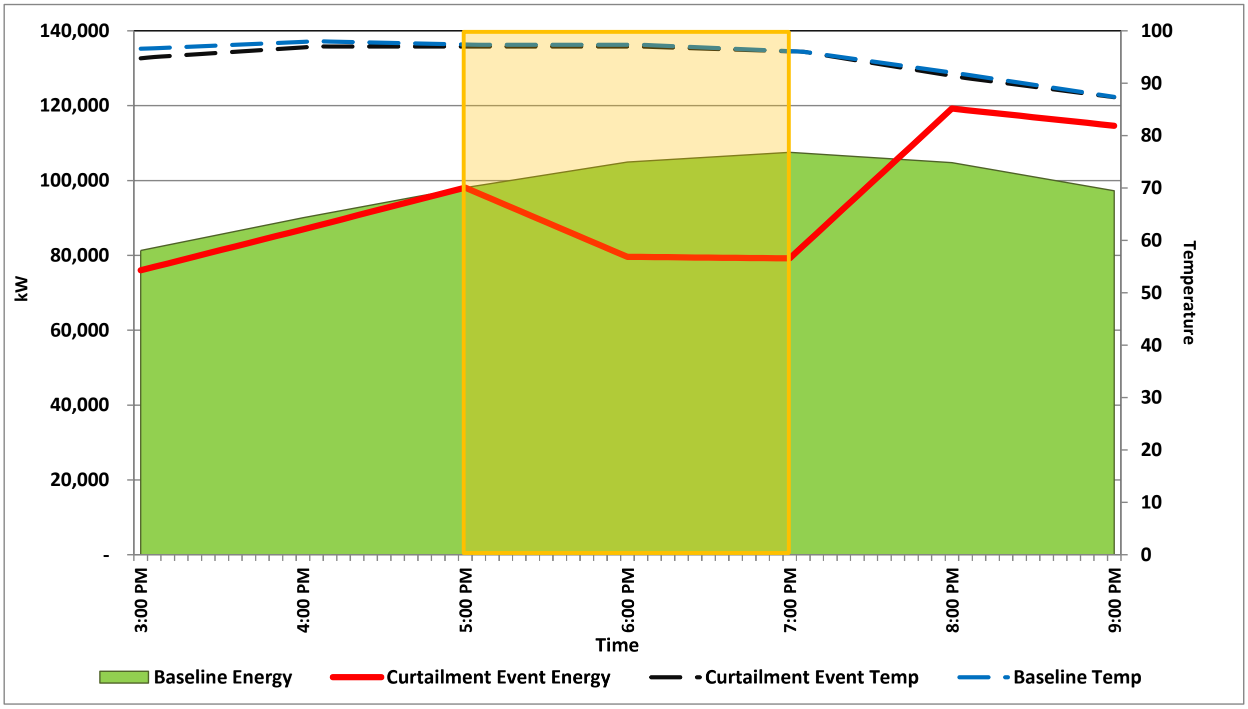


Figure 73. July 31 Curtailment Results: AMI – Twin Falls / Pocatello Region

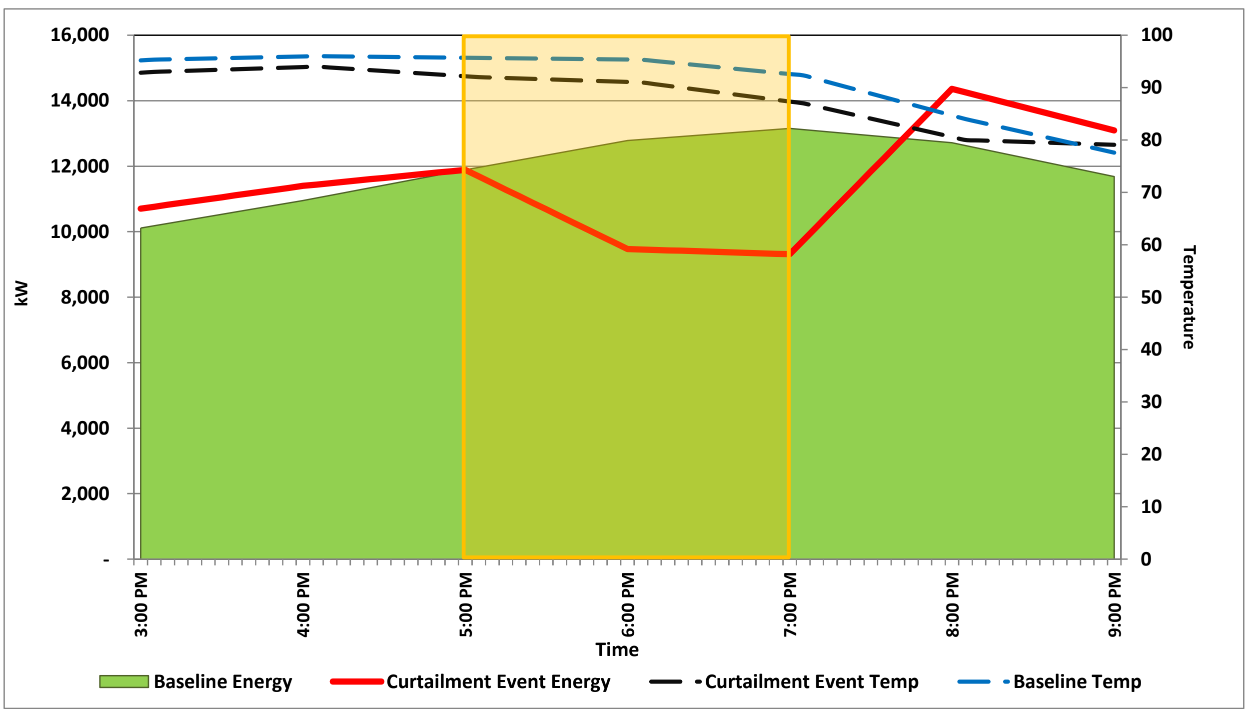


Figure 74. July 31 Curtailment Results: Loggers – Boise Metro Region

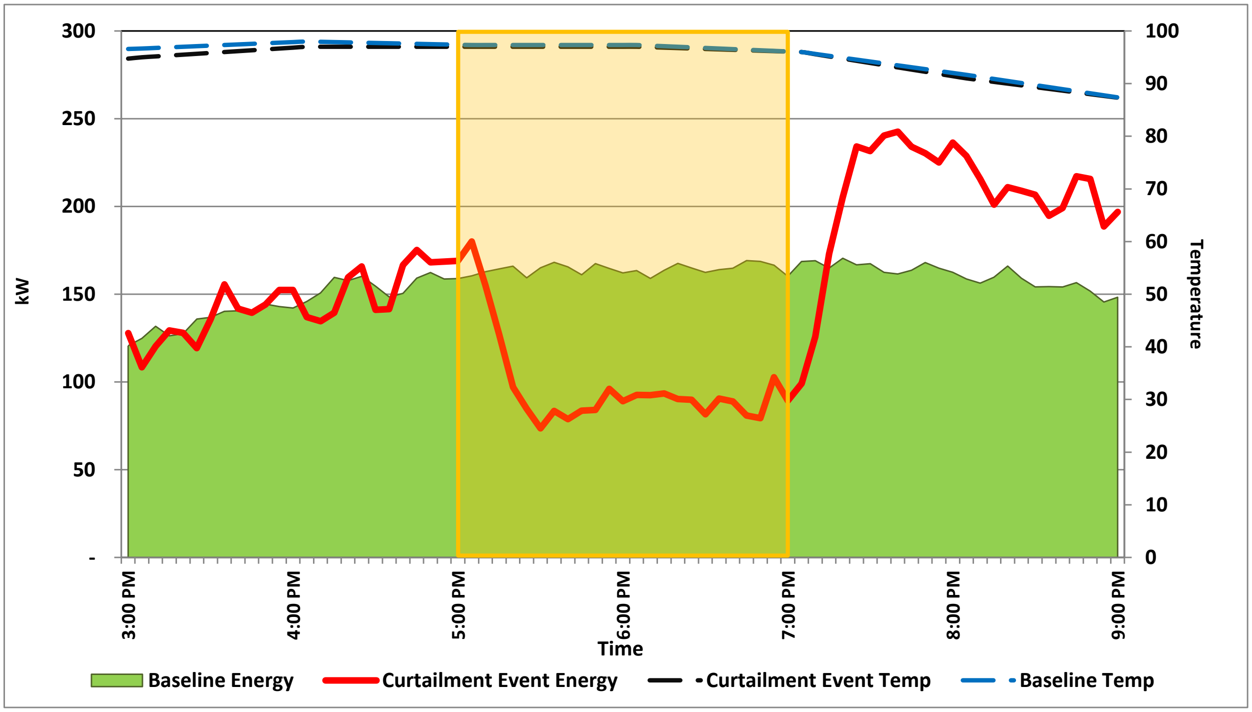
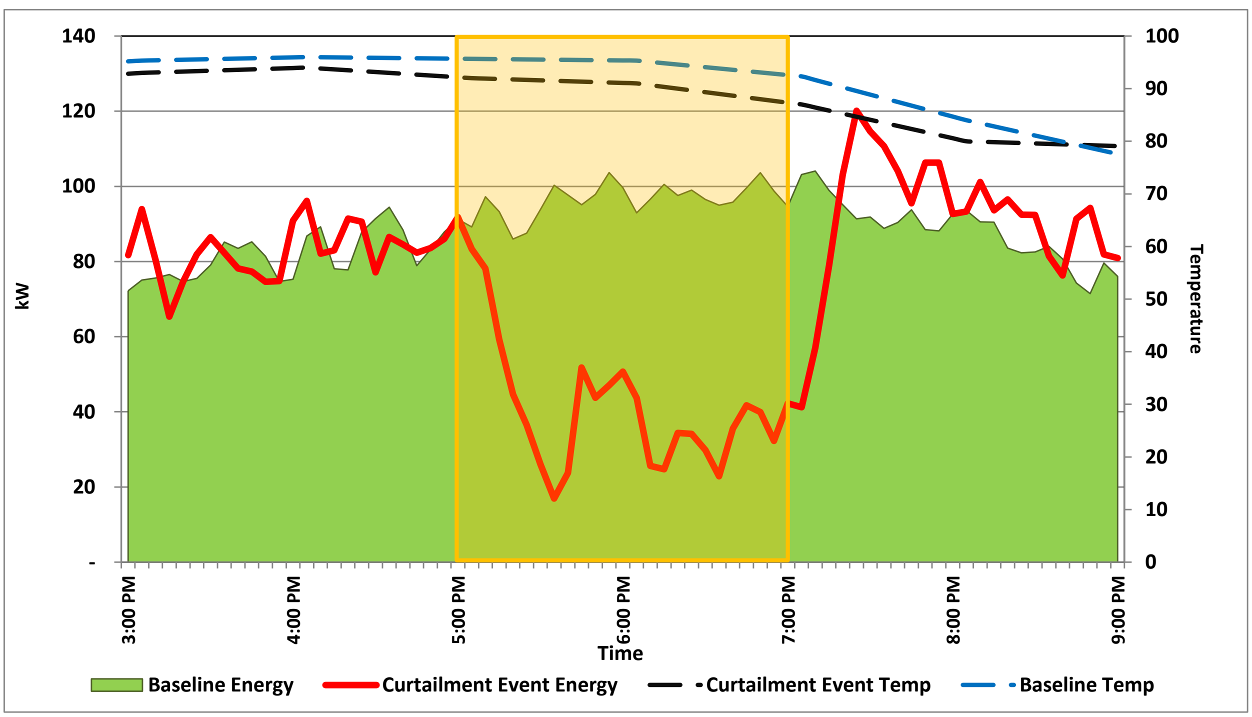


Figure 75. July 31 Curtailment Results: Loggers – Twin Falls / Pocatello Region



August 13 Curtailment

Event Details:
Time: 4-7 pm
Notes: Curtailment: 50%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	97	0.32	0.40	0.35	0.36
TF/Pocatello	93	0.38	0.44	0.37	0.42
All	97	0.33	0.40	N/A	N/A

Figure 76. August 13 Curtailment Results: AMI – Both Regions

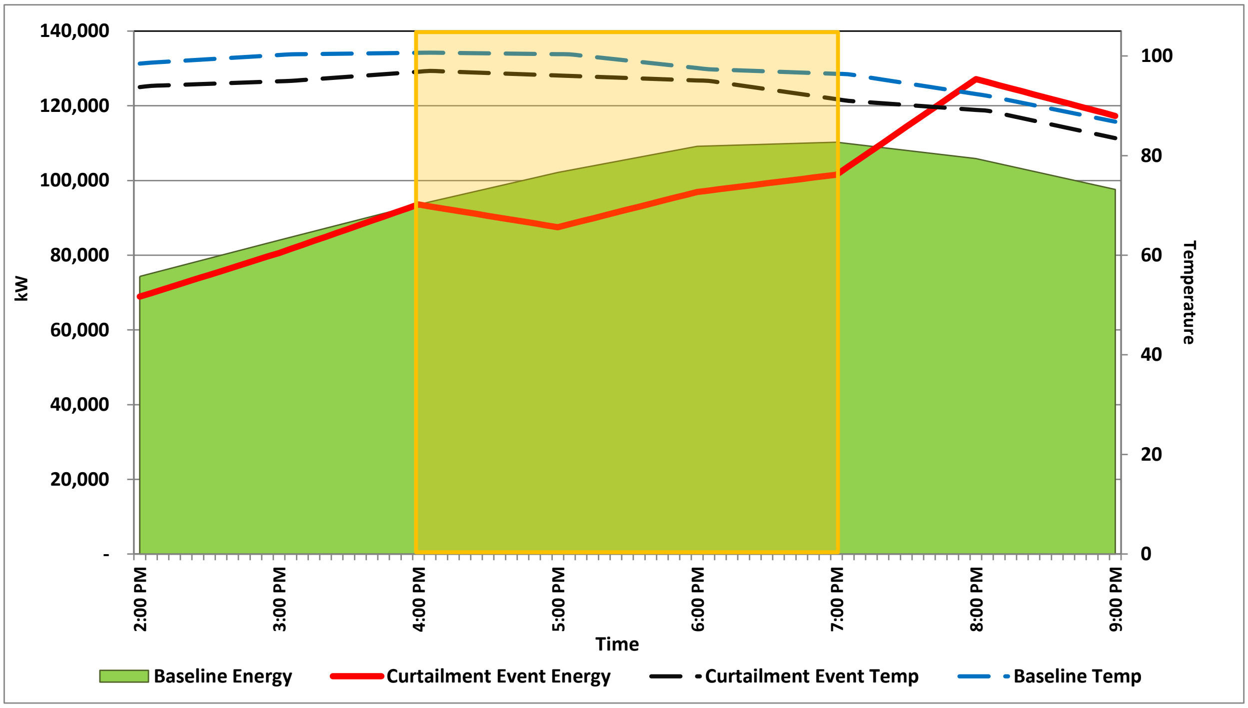


Figure 77. August 13 Curtailment Results: AMI – Boise Metro Region

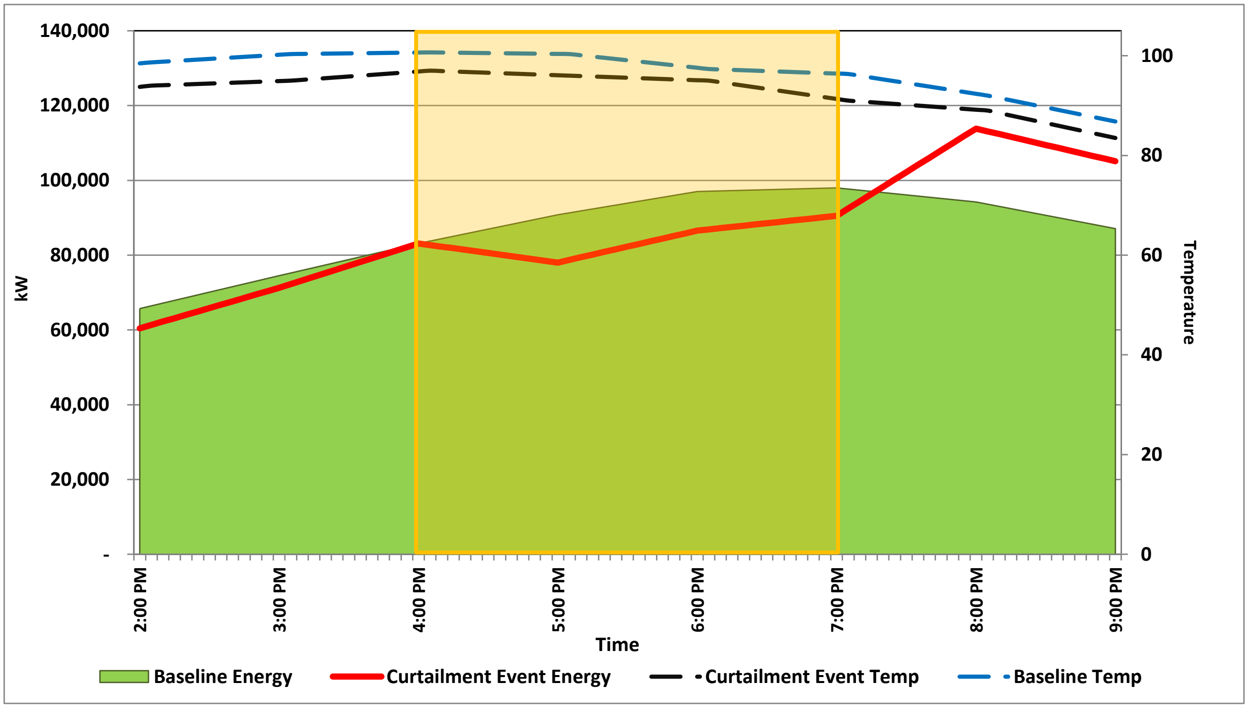


Figure 78. August 13 Curtailment Results: AMI – Twin Falls / Pocatello Region

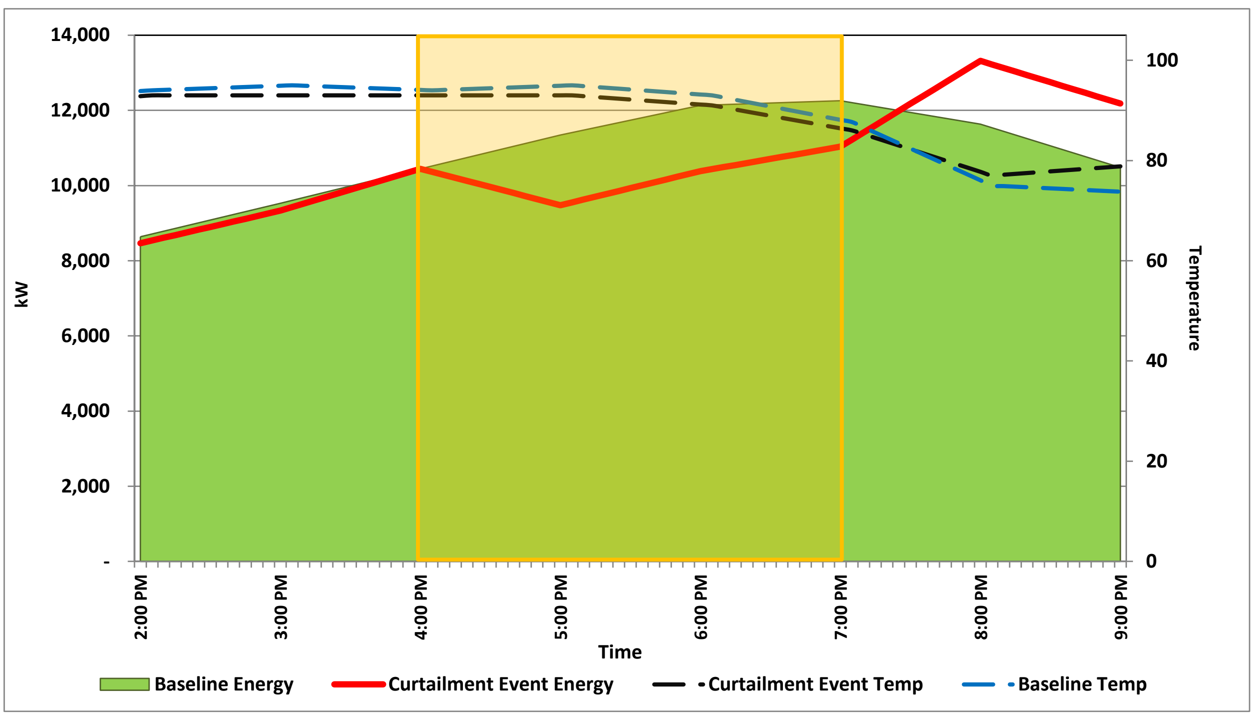


Figure 79. August 13 Curtailment Results: Loggers – Boise Metro Region

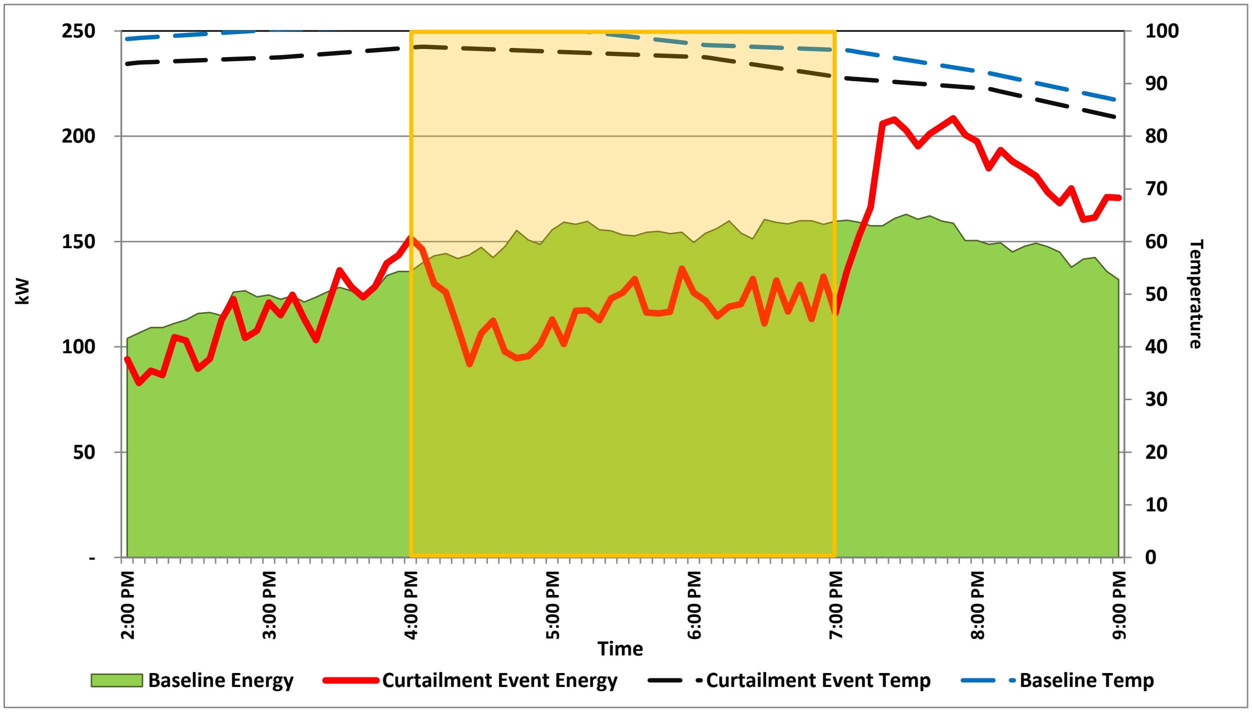
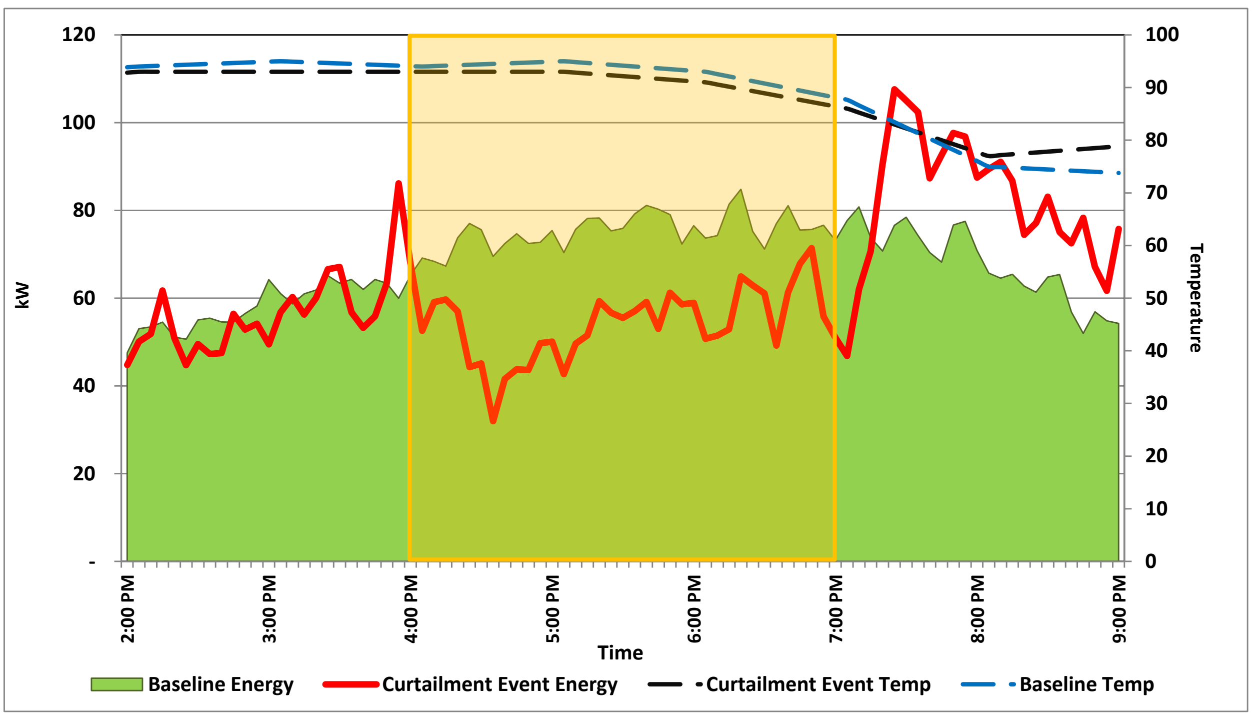


Figure 80. August 13 Curtailment Results: Loggers – Twin Falls / Pocatello Region



August 16 Curtailment

Event Details:
Time: 4-8 pm
Notes:
Curtailment: 75%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	93	0.79	0.83	0.84	0.91
TF/Pocatello	92	0.56	0.59	0.68	0.76
All	93	0.76	0.80	N/A	N/A

Figure 81. August 16 Curtailment Results: AMI – Both Regions

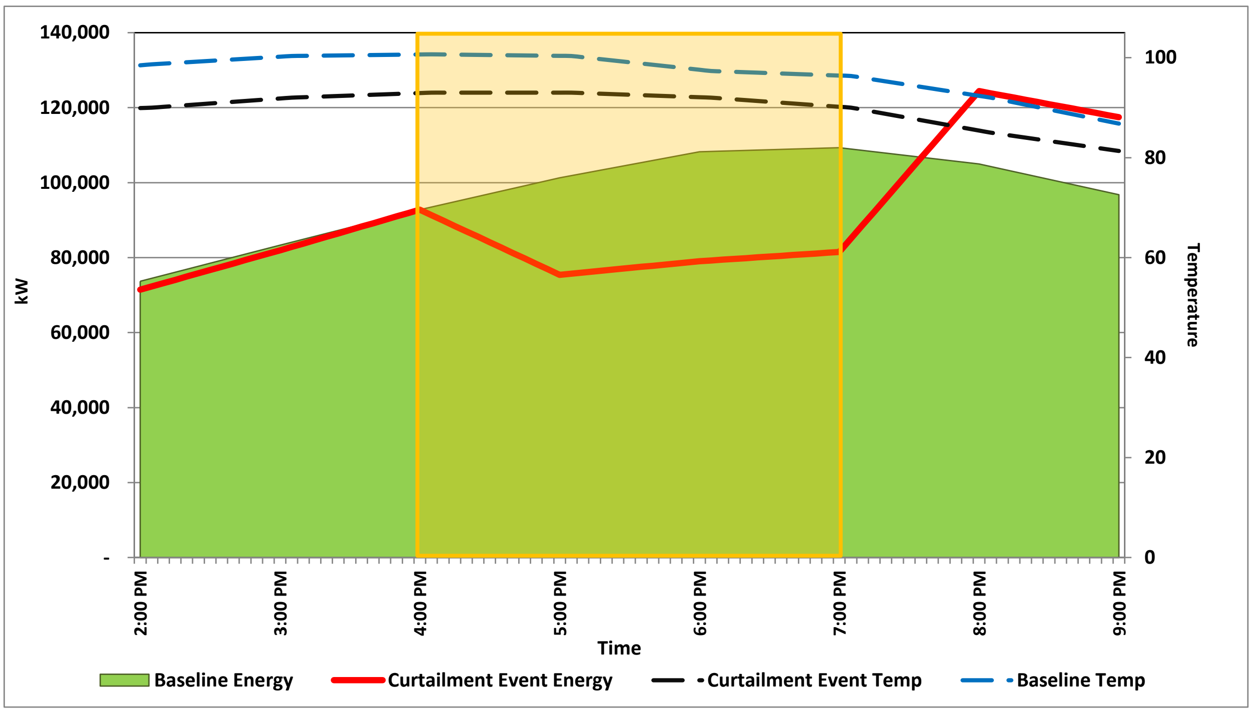


Figure 82. August 16 Curtailment Results: AMI – Boise Metro Region

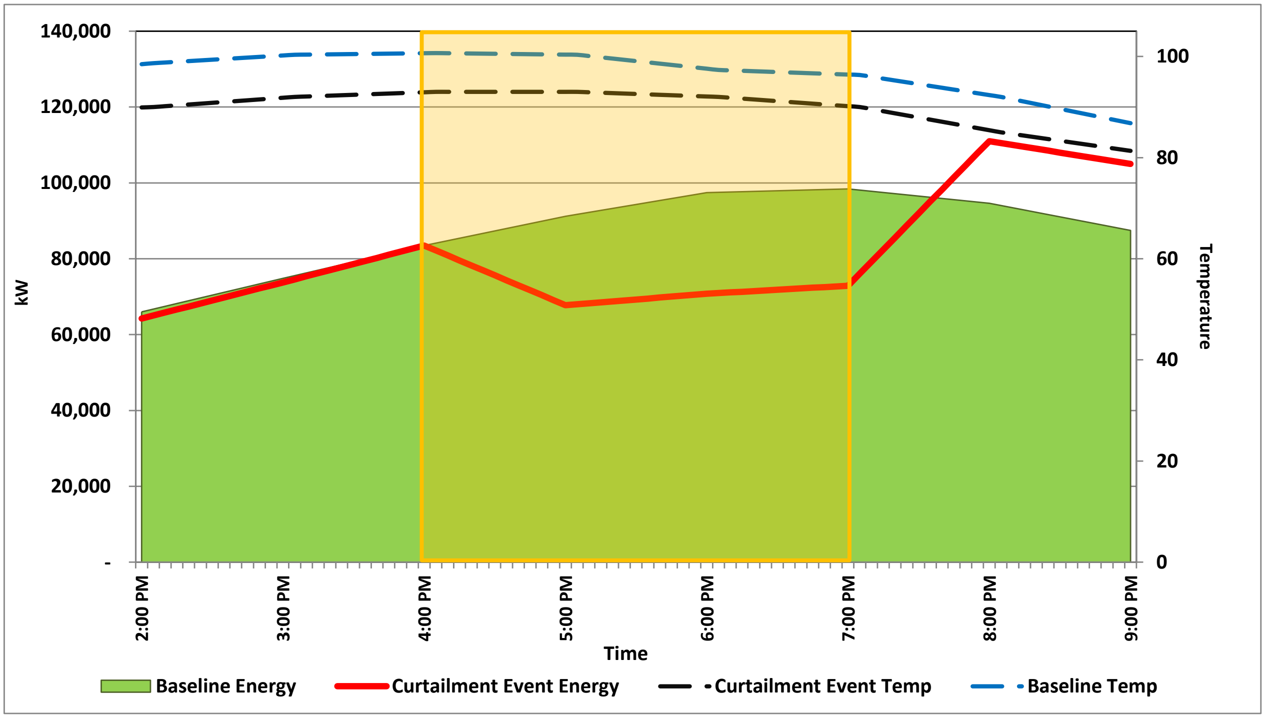


Figure 83. August 16 Curtailment Results: AMI – Twin Falls / Pocatello Region

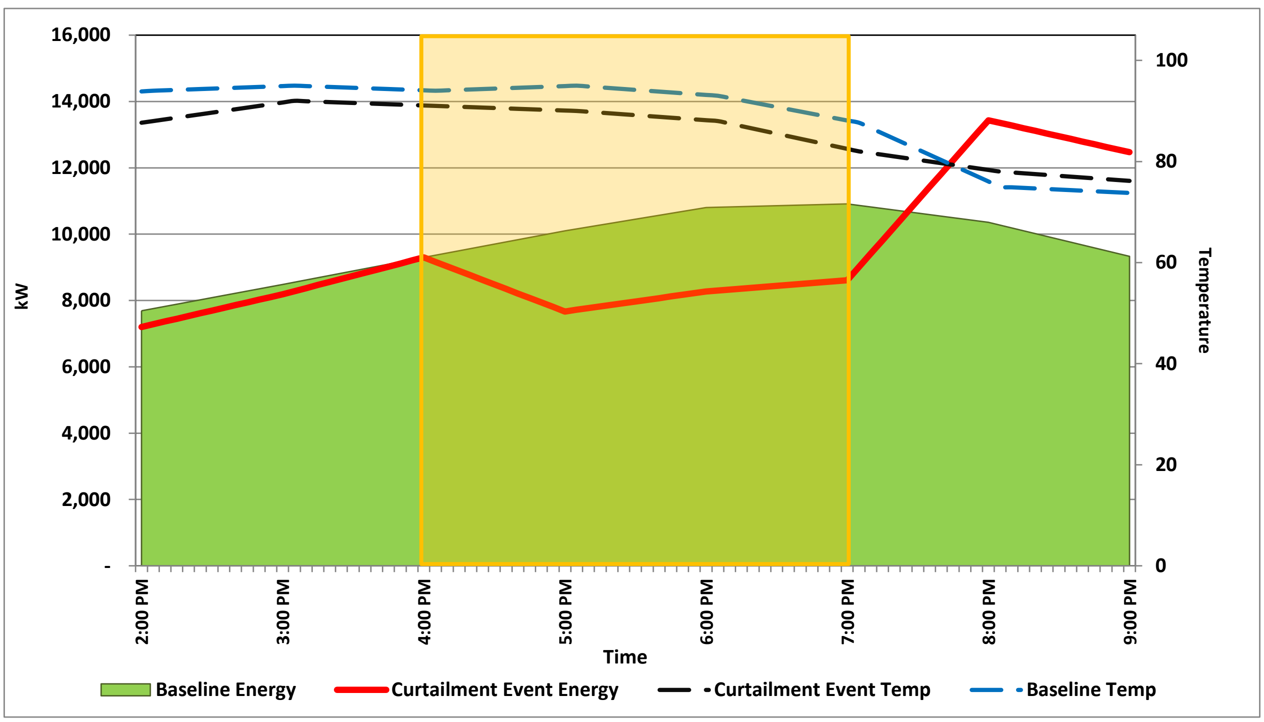


Figure 84. August 16 Curtailment Results: Loggers – Boise Metro Region

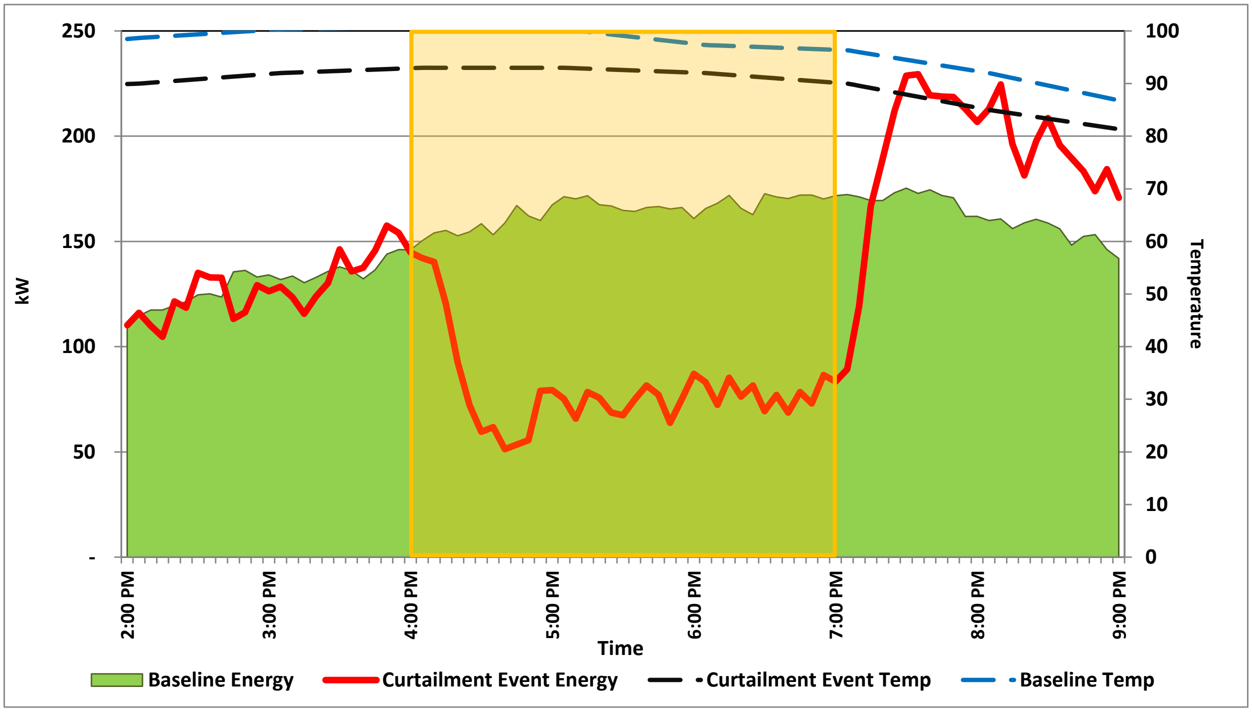
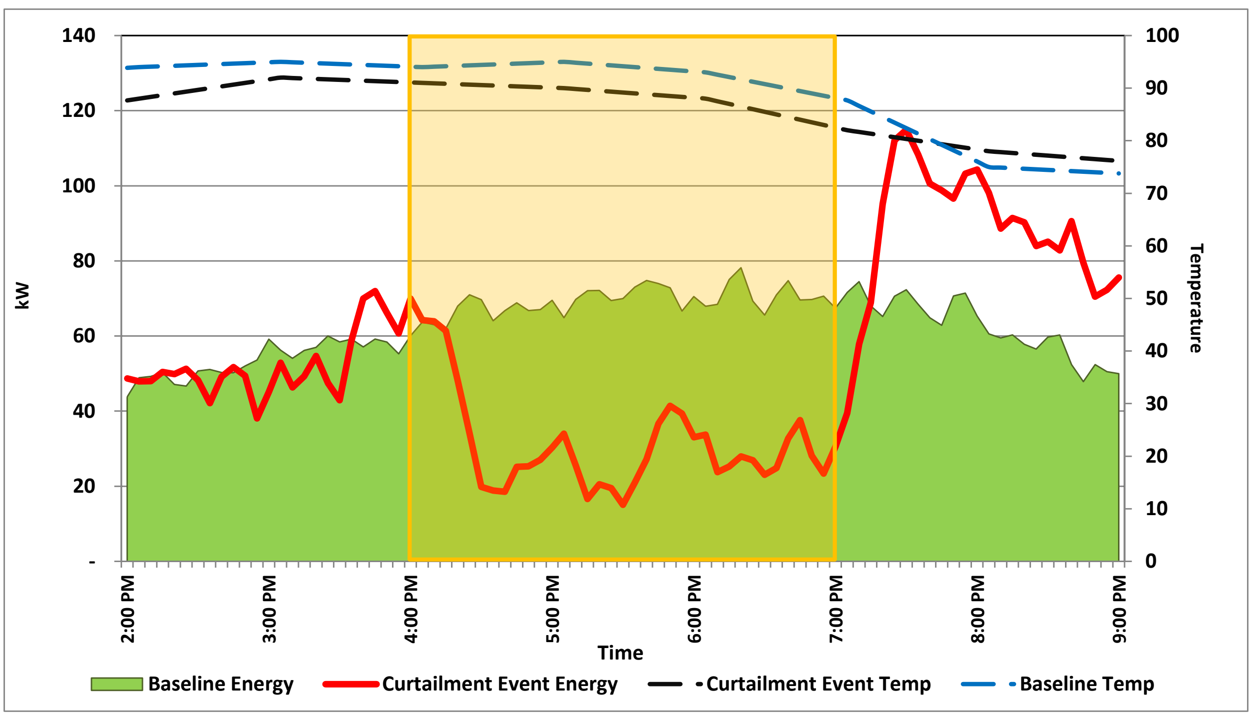


Figure 85. August 16 Curtailment Results: Loggers – Twin Falls / Pocatello Region



August 20 Curtailment

Event Details:
Time: 4-7 pm
Notes:
Curtailment: 65%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	94	0.55	0.58	0.56	0.61
TF/Pocatello	86	0.47	0.52	0.48	0.55
All	94	0.54	.57	N/A	N/A

Figure 86. August 20 Curtailment Results: AMI – Both Regions

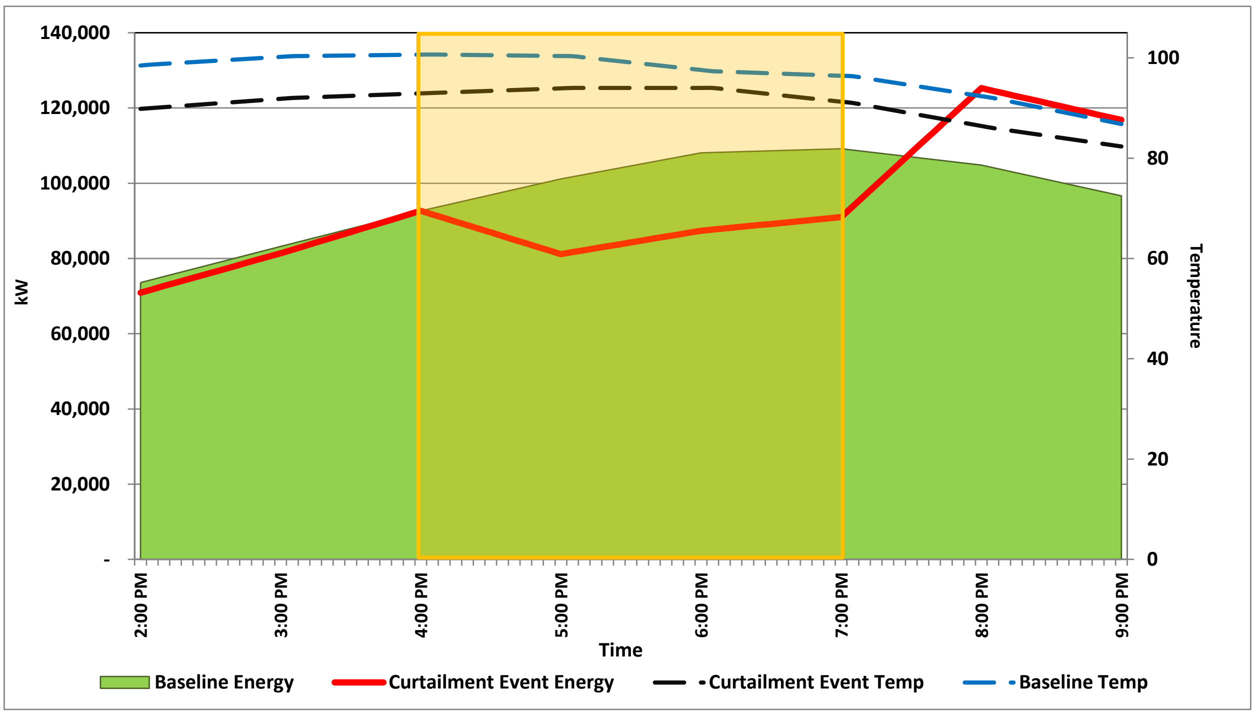


Figure 87. August 20 Curtailment Results: AMI – Boise Metro Region

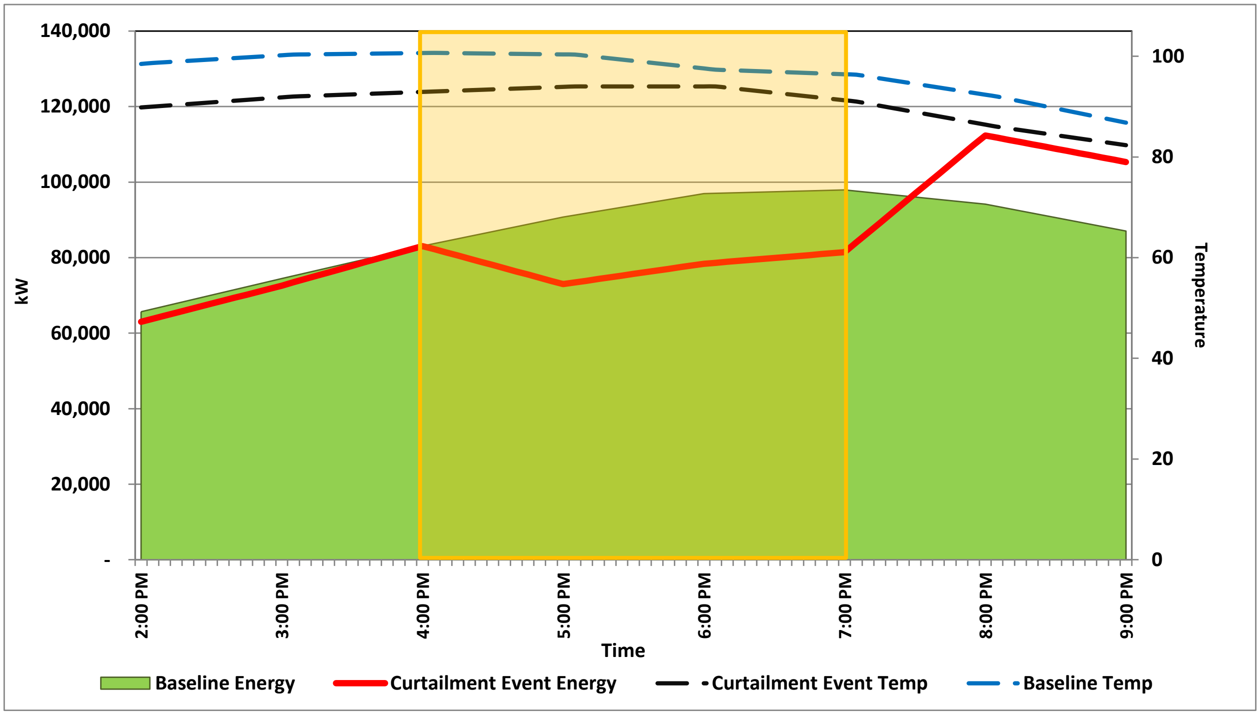


Figure 88. August 20 Curtailment Results: AMI – Twin Falls / Pocatello Region

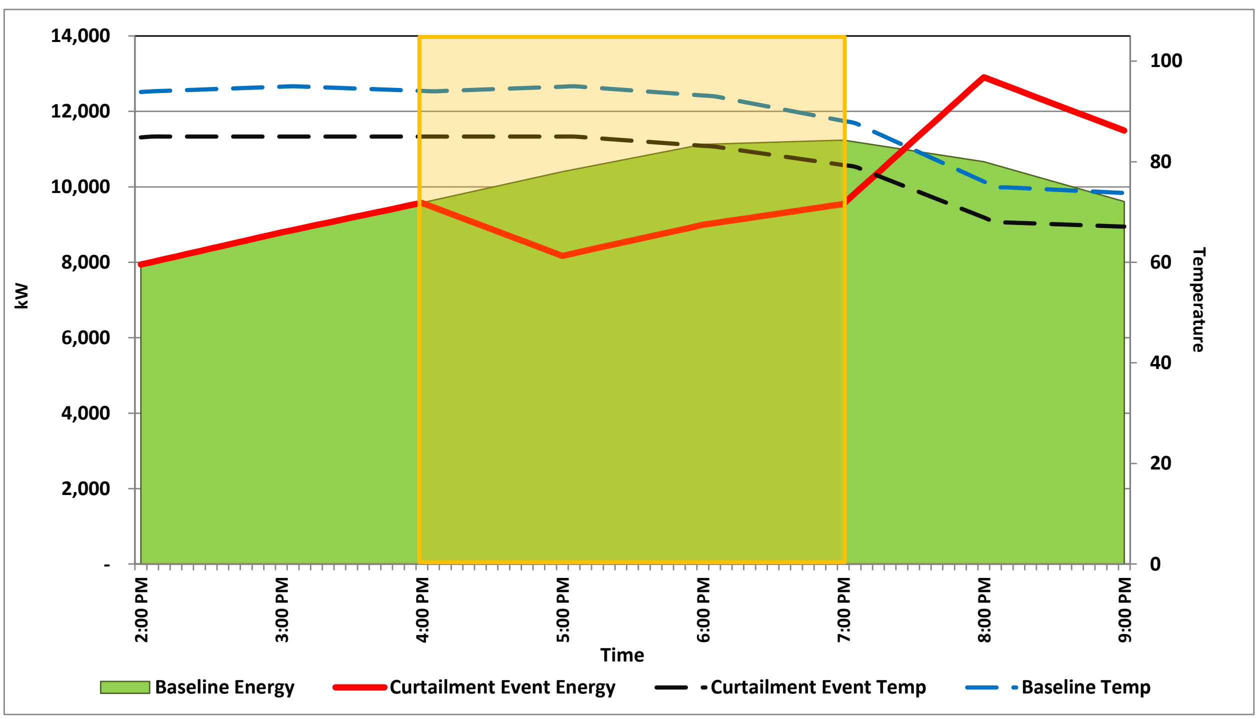


Figure 89. August 20 Curtailment Results: Loggers – Boise Metro Region

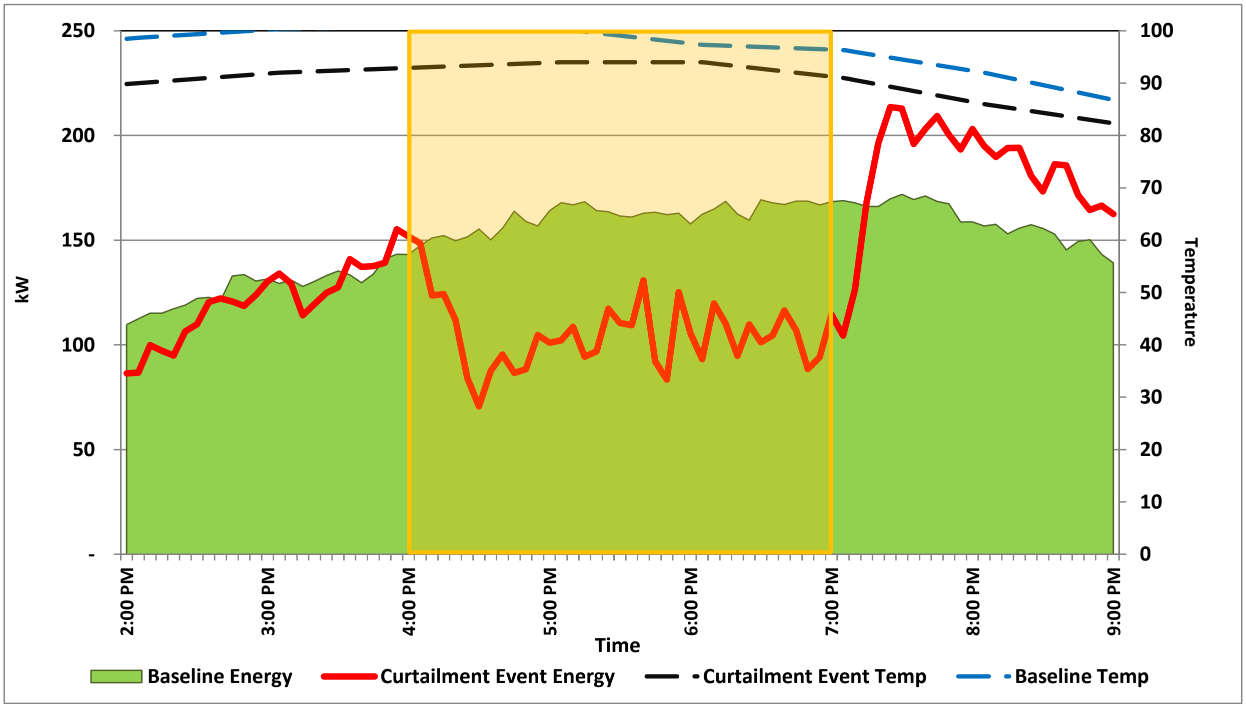
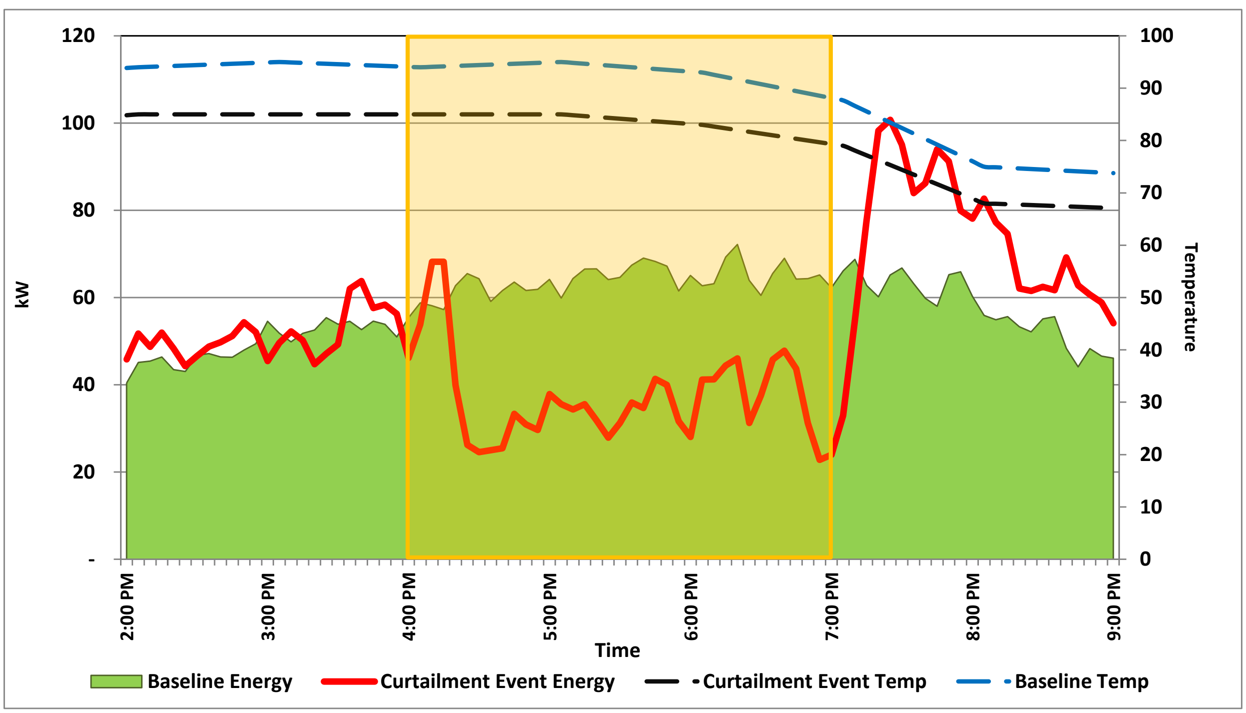


Figure 90. August 20 Curtailment Results: Loggers – Twin Falls / Pocatello Region



August 22 Curtailment

Event Details:
Time: 5-6 pm
Notes:
Curtailment: 100%

Region	Hi Temp	AMI Data		Logger Data	
		Ave. kW Reduction	Max kW Reduction	Ave. kW Reduction	Max kW Reduction
Boise Metro	90	0.86	0.86	0.77	0.77
TF/Pocatello	89	0.75	0.75	0.67	0.67
All	90	0.85	0.85	N/A	N/A

Figure 91. August 22 Curtailment Results: AMI – Both Regions

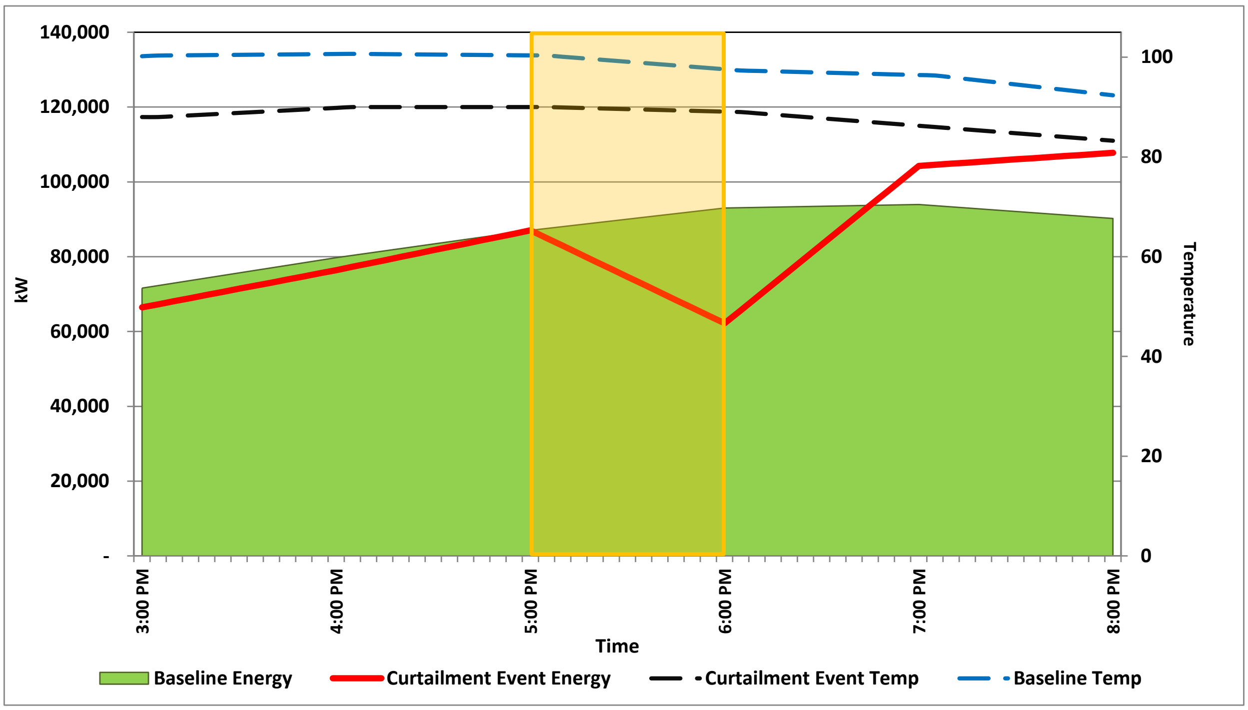


Figure 92. August 22 Curtailment Results: AMI – Boise Metro Region

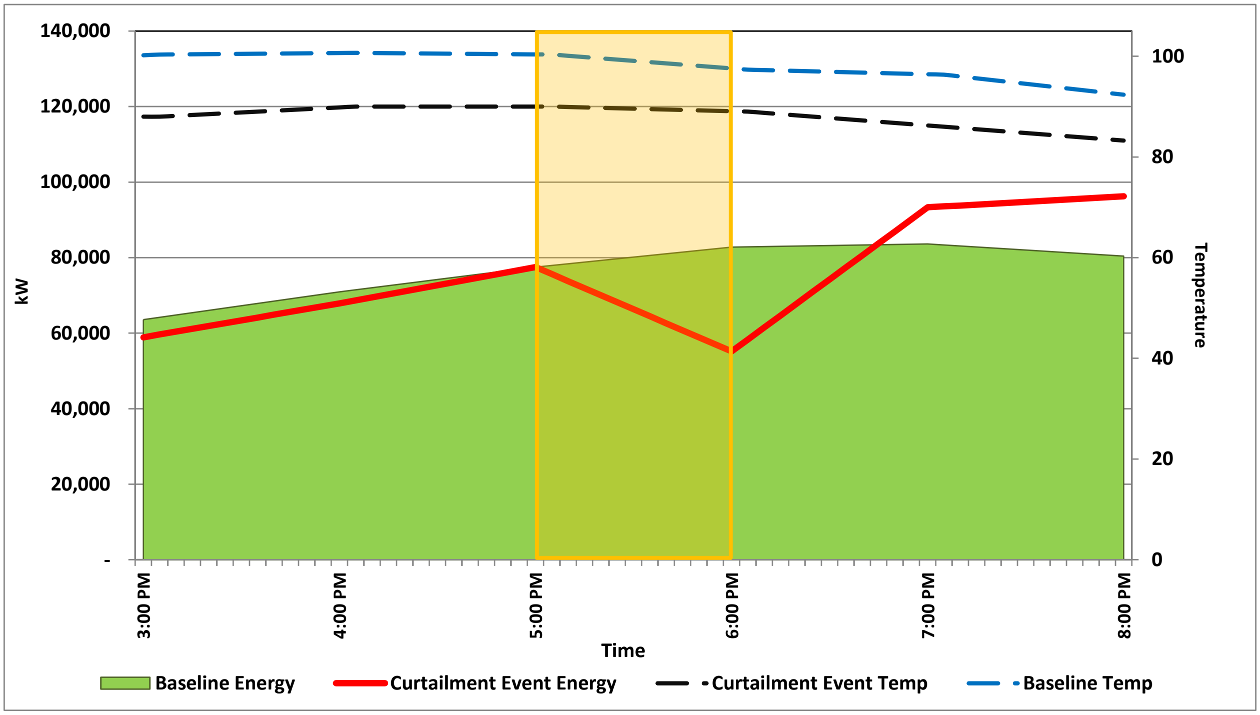


Figure 93. August 22 Curtailment Results: AMI – Twin Falls / Pocatello Region

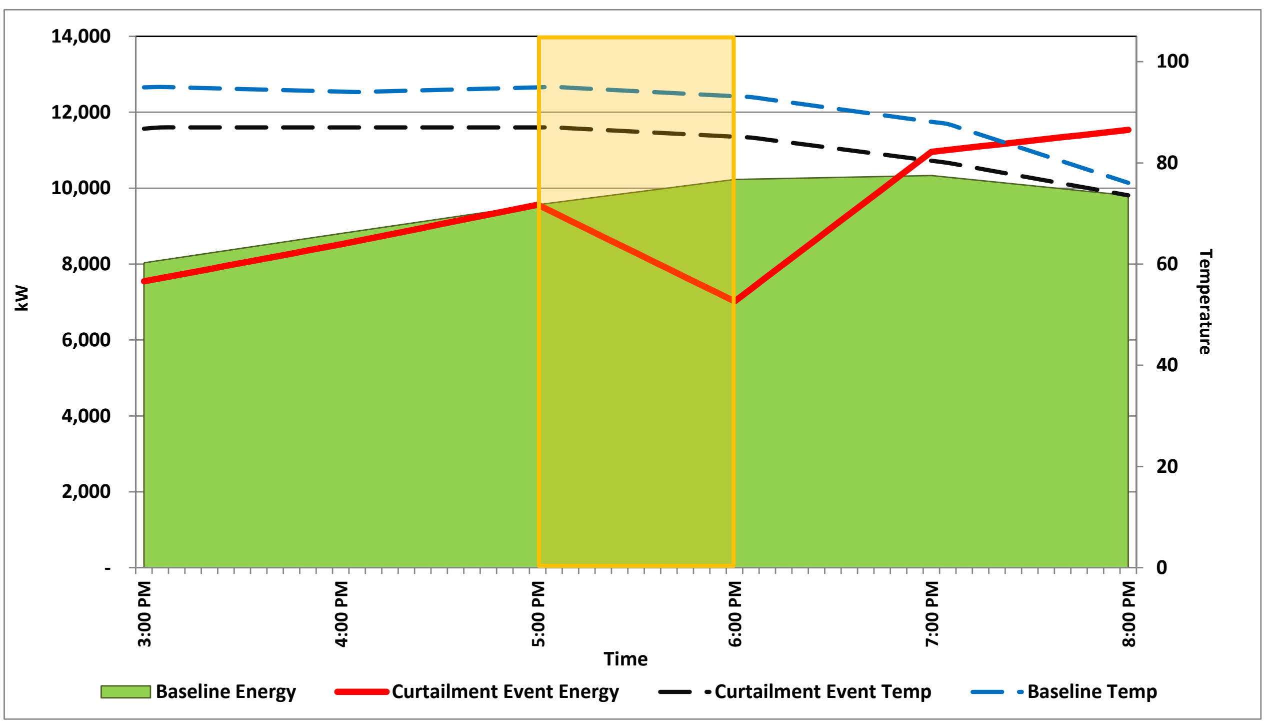


Figure 94. August 22 Curtailment Results: Loggers – Boise Metro Region

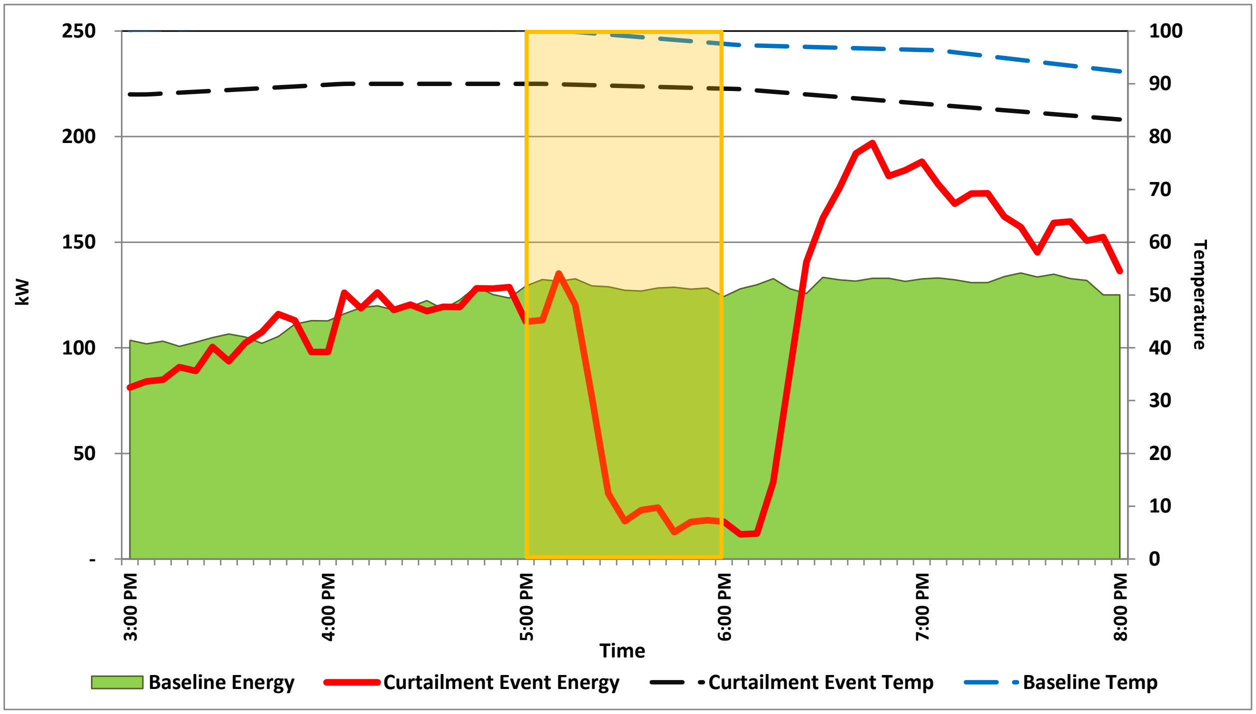
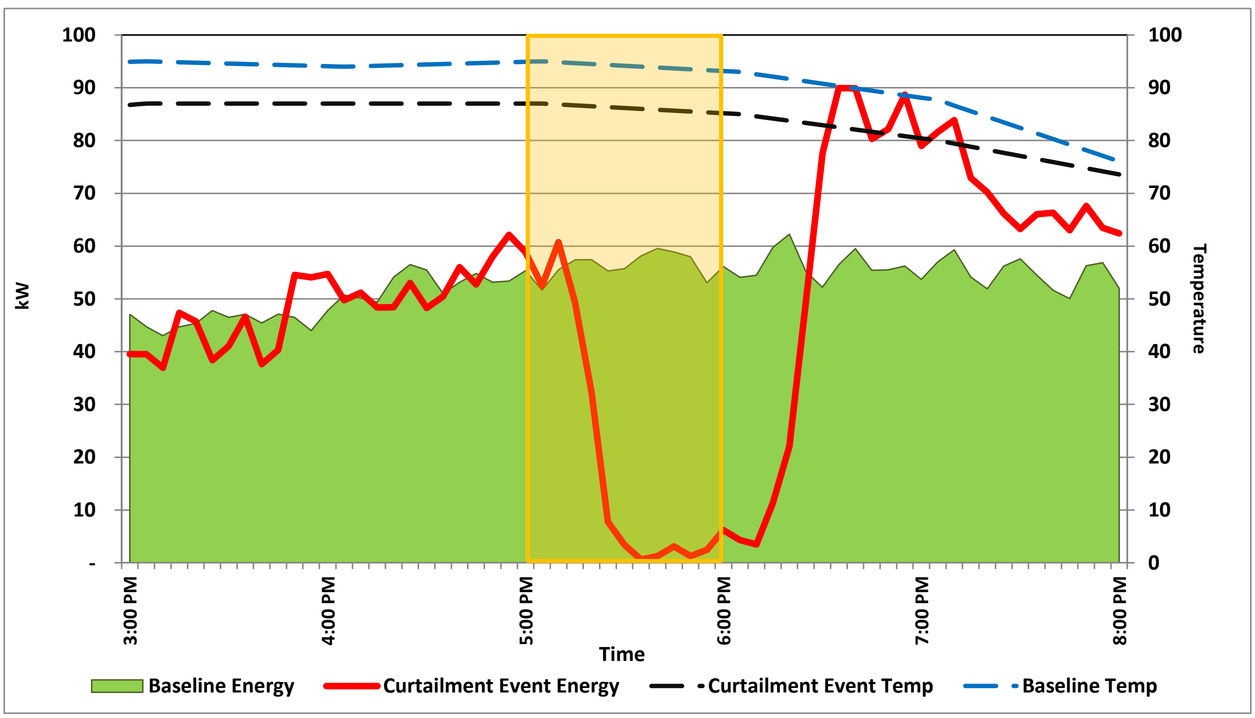


Figure 95. August 22 Curtailment Results: Loggers – Twin Falls / Pocatello Region



IDAHO POWER COMPANY

2013 SMART GRID REPORT

Appendix D-10

Renewable Integration Tool Project Summary

Renewables Integration Tool Project Summary

September 2012

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1. BACKGROUND

1.1. Smart Grid Investment Grant

In August 2009, Idaho Power Company (IPC) applied for and was awarded a Smart Grid Investment Grant (SGIG) from the Department of Energy (DOE) to fund multiple smart-grid projects. One of these projects was the Renewables Integration Tool (RIT) project. The RIT project's intention was to develop tools to allow grid operators and Power Supply transaction specialists to efficiently and reliably integrate variable renewable resources with traditional generation resources.

1.1.1. Increased Wind Generation

Due to the recent increase in stimulus funds and tax credits for renewable-energy projects, there has been a dramatic increase in the wind generation incorporated into IPC's system (figures 1 and 2); developers have been submitting new wind projects under the *Public Utility Regulatory Policies Act of 1978* (PURPA).

Figure 1
Wind-generation capacity: 2004–2013

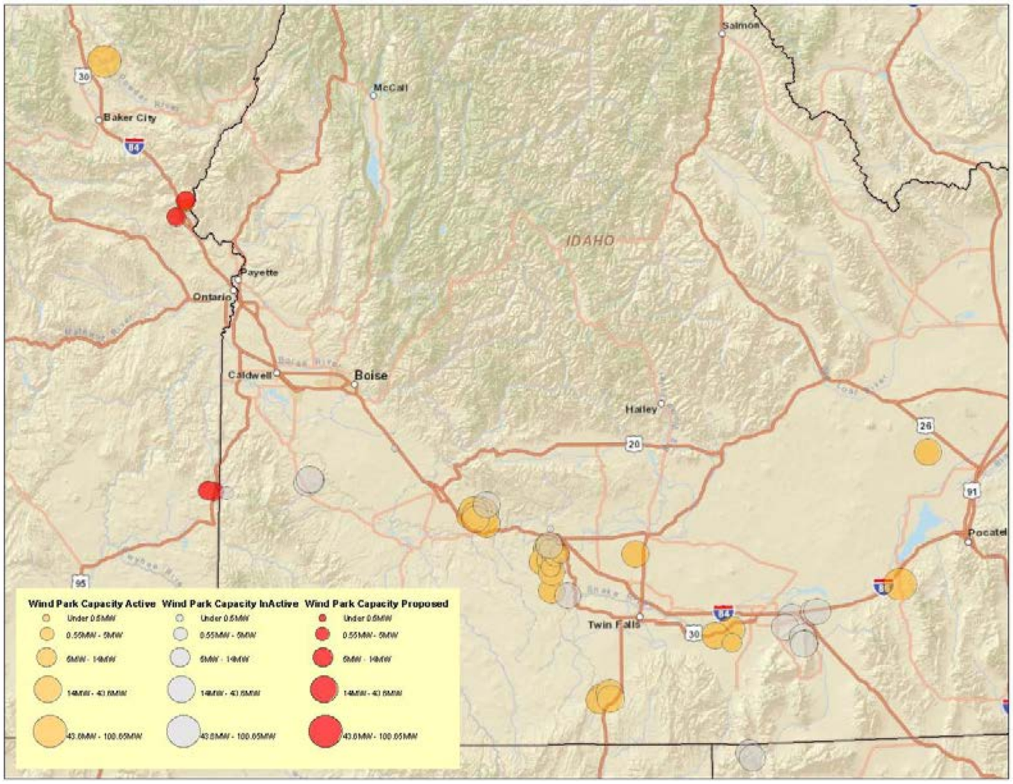


Figure 2
Wind-generation map: existing and proposed sites

However, wind generation is variable, making it difficult for the IPC Operations department (Operations), which balances electrical supply and demand on a long- and short-term basis, to integrate wind generation into IPC's balancing authority in the most reliable and economical manner. For example, wind generation typically comprises about 5.5 percent of IPC's generation capabilities (Figure 3), but it occasionally comprises between 25 to 35 percent of IPC's system load (Figure 4).

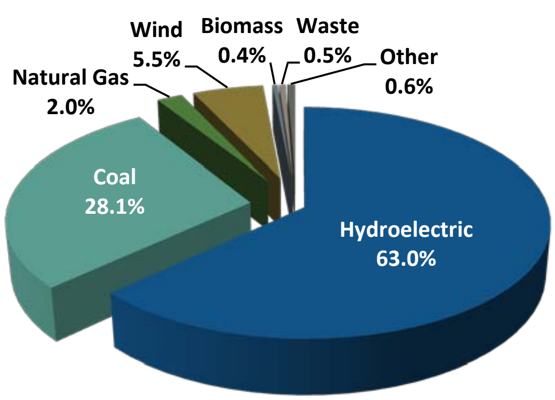


Figure 3
2011 fuel mix

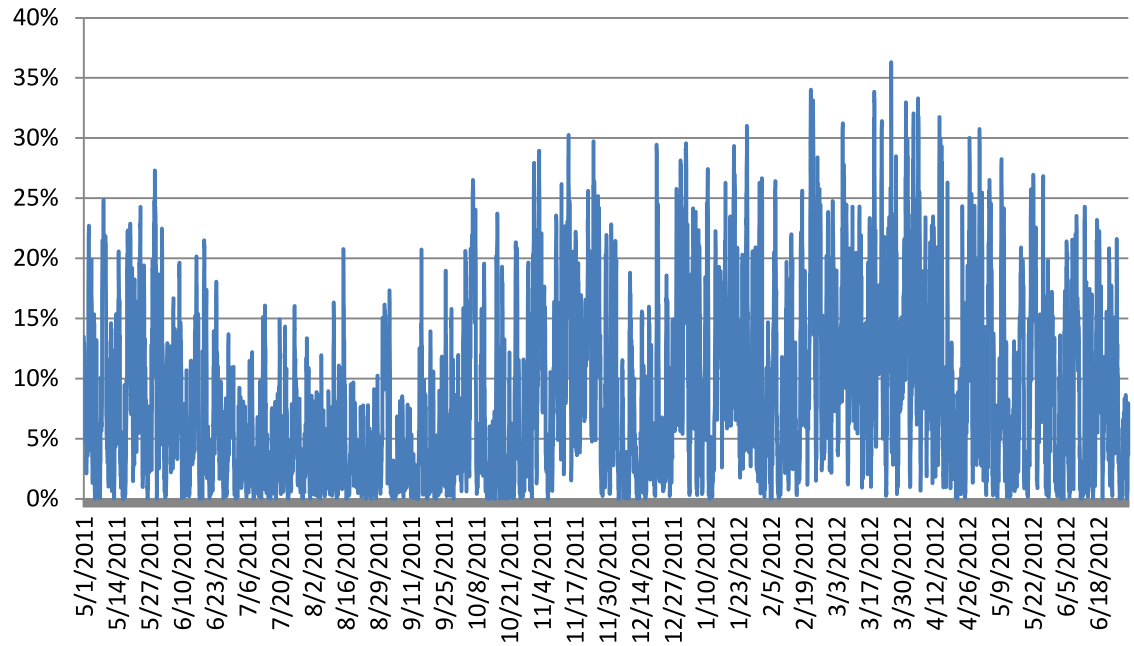


Figure 4
Wind power as a percent of the system load: 5/2011–6/2012

Because of this variability in wind generation, Operations pre-schedule and real-time transaction specialists need a consistent and accurate wind-generation forecasting tool. Without this forecasting tool, transaction specialists are often required to carry additional operating reserves to ensure there is always sufficient generation to cover an unplanned loss of large amounts of wind generation. Carrying such additional operating reserves can be very costly and results in inefficient operating of the generation system.

1.1.2. Project Goal

To account for the variability in generation resources, the RIT project was implemented to develop tools to allow grid operators and Power Supply transaction specialists to efficiently and reliably integrate variable renewable resources from large generation interconnect and PURPA wind projects with traditional generation resources. The project goal was to yield three wind forecast intervals: a short-term demand forecast, an enhanced regulating margin forecast, and a spinning reserve forecast.

1.1.2.1. Wind Forecast Intervals

1.1.2.1.1. Pre-Schedule Wind-Generation Forecast

Developing an accurate pre-schedule wind-generation forecast tool has significant advantages for reliably and efficiently integrating renewable generation; an accurate pre-schedule forecast allows pre-schedulers to more closely match supply and demand prior to the real-time horizon. In other words, a more balanced pre-schedule system helps ensure there is sufficient supply to meet demand. As a result, less energy needs purchased or sold in the real-time market, which typically has a higher risk of adverse price volatility.

1.1.2.1.2. Real-Time Wind-Generation Forecast

Developing an accurate real-time wind-generation forecast tool would also significantly lower costs associated with trading in the real-time market by further reducing the amount of energy that needs purchased or sold to account for unplanned increases/decreases in wind generation. A more accurate real-time wind-generation forecast also improves the reliable operation of the system by helping ensure sufficient operating reserves are maintained to cover forecasted reductions of wind generation and by ensuring there is sufficient generation on-line that can be reduced to cover forecasted increases in wind generation.

1.1.2.1.3. 30/60-Minute Rolling Wind-Generation Forecast

Developing a 30/60-minute rolling wind forecast tool would benefit Generation and Transmission dispatchers, who have similar challenges in balancing supply and demand while operating the system in a safe, reliable, and compliant manner.

1.1.2.2. Short-Term Demand Forecast

By developing a short-term demand forecast, IPC would be able to provide demand forecast values for short intervals (e.g., five minutes) that would be continuously updated every five minutes and give a more accurate idea of the generation required to balance the system.

1.1.2.3. Enhanced Regulating Margin Forecast

Enhancing the regulating margin forecast would provide a more accurate idea of where the balance of the system would be in 10 and 60 minutes, which would allow operators to proactively balance the system.

1.1.2.4. Spinning Reserve Forecast

Developing the spinning reserve forecast would provide a more accurate idea of where the spinning reserve balance would be in 30 and 60 minutes. This would allow operators to proactively know when they have to commit more generating resources to an operational mode for keeping the required spinning reserve number within regulating limits.

1.2. Existing Processes

1.2.1. Wind Forecasting

Prior to the RIT project, IPC developed an in-house wind-generation forecast using coarse National Weather Service data and rating curves developed by the IPC Power Supply Planning department. This system showed potential but needed further research and development to become an operational tool. This project provided the basis for the current RIT wind forecasting tool.

1.2.2. Pre-Scheduling Activity

To determine pre-schedule activity data, a transaction specialist estimated the amount of wind-generation megawatts (MW) on the system for the forecast period. Transaction specialists used many values, including 33 percent of wind-generation nameplate capacity and a three-day rolling average. For the most part, this process did not take into account weather forecasts.

1.2.3. Real-Time Activity/Hourly Activity

To gather real-time and hourly activity data, transaction specialists watched a wind gage or the current wind generation and adjusted as the system changed. A meteorologist provided the operators with a forecast map, and the operators interpreted the MW using a crude chart.

1.2.4. Short-Term Demand Forecast

Prior to the RIT project, the short-term demand forecast provided only hourly intervals and was generated daily.

1.2.5. Regulating Margin Forecast

The regulating margin forecast value was based on one percent of the total system load. This was a guideline based on current load instead of a forecasted future load because IPC lacked a wind forecast tool and a demand with a short-term forecast on which to base future values.

1.2.6. Spinning Reserve Forecast

Prior to the RIT project, only current spinning reserve values were available because IPC lacked a wind forecast tool and a demand with a short-term forecast on which to base future values.

2. METHODS

2.1. Wind Forecast

2.1.1. Investigation of Existing Tools and Processes

In 2010, the Idaho Public Utilities Commission (IPUC) asked IPC to determine if an in-house wind forecast could be developed instead of purchasing wind forecasts from vendors; at that time, 3TIER provided the forecast for the Elkhorn Valley wind park. To determine the best forecast, IPC tested three options: 1) the 3TIER forecast, 2) persistence (using the previous observed condition), and 3) a two-month data set of Weather Research and Forecast (WRF) model forecasts provided by the University of Arizona (UA). The WRF model wind forecast was converted to power forecasts for the wind park using locally developed power curves, and an evaluation was conducted to determine which of the three forecasts was best. Results showed that the WRF forecast was an improvement over the other two forecasts methods. In addition to testing these three forecasts, IPC contacted the Bonneville Power Administration (BPA) to analyze its in-house forecast but determined the BPA's methodology (using an ensemble blend of low-resolution models) was not better than the WRF model. The National Center for Atmospheric Research (NCAR) also briefed IPC on its wind-power forecast software developed for Excel energy, but the initial and ongoing anticipated costs of this software would cost more than developing the WRF forecast in house. During this time, the DOE SGIG funds became available for this project, and IPC proceeded to develop the WRF forecast method using those funds.

2.1.2. Data Used

2.1.2.1. WRF Model

To develop the WRF forecast in house, IPC contracted services from the UA to provide the weather forecast output of the WRF model. IPC selected the UA because its WRF model had similar geographic characteristics, and the UA was able to modify the model for IPC's service area.

The model output consists of wind forecasts derived from weather forecasts. Model forecasts are derived from two models with different initialization files—the WRF-North American Model (NAM) and the WRF-Global Forecast System (GFS). Both models provide weather forecasts for points located at the corners of every square mile of the IPC service area at multiple elevations and for each hour. The WRF-NAM is run four times a day for 72 hours into the future, while the WRF-GFS is run once Monday through Friday for 180 hours into the future. The WRF-NAM is the primary forecast model for real-time and pre-schedule forecasts, and WRF-GFS data is used as a backup in the short-term and as the primary forecast model for time frames past 72 hours.

The UA also provided the large amount of computer-processing capability and data storage needed to create the WRF forecasts. The UA Beowulf cluster supercomputer contains over 900 processors. Two domains are used: the inner 1.8-kilometer (km) domain was designed to cover existing and planned wind parks in Idaho and Oregon, and the outer 5.4-km domain is used to initialize the 1.8-km domain and covers the Horseshoe Bend wind park in Montana.

Another model IPC uses is the rapid refresh model (formerly the rapid update cycle [RUC40]), which forecasts hourly. Other models available but not yet used by IPC include the MRF80, AVN96, GFS96, and SREF.

2.1.2.2. Observation Data

Meteorological towers at the following wind parks provided observation data:

- **Elkhorn Valley.** Two wind towers are located northwest and southeast of a small hill in the center of the wind park. The physical locations reduce the accuracy of the wind speeds.

- **Mountain Air.** The wind park has two wind towers planned, one located on the southwest side and the other on the northeast side of the wind park.

- **Bell Rapids.** One tower is located at Pilgrim Station and another tower will be installed after the High Mesa wind-park turbines are installed (December 2012).

- **Golden Triangle.** One tower is located near the Milner Dam wind park.

- **Rockland.** One tower is located on the northwest side, and the other on the northeast side of the wind park. These locations miss the critical southern part of the wind park.

Wind data is also collected from hubs at wind parks. Currently, data for the Bell Rapids and Golden Triangle wind parks is available.

Surface weather observations are obtained from the Federal Aviation Administration (FAA), Remote Automatic Weather Stations (RAWS), and other agency networks. In addition, a wide variety of weather observation data is available via the MesoWest website.

2.1.3. Building of Analysis Tools

2.1.3.1. Analysis Database

The first step in building IPC's wind-power forecast was to build a database containing weather forecast data, observed weather data, and actual wind-park generation data.

To build this database, forecast data for a large set of geographic points near each wind park being evaluated was extracted. This data was analyzed to determine which points correlated most closely to observed power at the wind park. Only the forecast data that was judged most useful was loaded into the database to reduce data size and increase performance.

The following data was also loaded into the database:

- Multiple forecast types (WRF-NAM, WRF-GFS, and RUC40)

- Data from weather observation stations located near the wind parks that was downloaded from the internet

- Observed power data from existing wind parks that was captured from the internal plant information (PI) system

- Observed data at turbines and owner-operated meteorological observation towers that was downloaded via internet access to wind-park-owner operation sites

The following essential database features were adhered to:

- The database contains a list of geographic points near wind parks that are useful for forecasting.

- Only those parameters useful for forecasting are extracted from the Gridded Binary (GRIB) weather model files and stored in the database (10-meter [m] wind, 80-m wind, etc.).

- The database uses a simple structure with the forecast type, forecast time, event time, and point name used as a key with model parameters contained in columns for efficiency.

- Degribbing of model files—extracting data from points in the GRIB files—is multi-threaded.

- Hash-code is generated in the loading program instead of using database-generated unique IDs.

2.1.3.2. Windalyzer

Along with the analysis database, an analysis tool—Windalyzer—was built simultaneously. Windalyzer's purposes include the following:

- Allows meteorologists to easily select time ranges, weather parameters, geographic locations, and forecast types and export the data to Excel for analysis

- Combines time-series data from multiple types of forecasts, weather observations, and wind-park generation observations

- Graphically shows forecast data, weather observations, and wind-park generation observations

- Allows for quickly spotting variation of parameters between geographic locations

- Enables the identification of relationships between parameters (10-m and 80-m wind speeds)

- Enables the identification of unique weather conditions (abrupt switch of wind direction with corresponding change of wind speed)

2.1.3.3. Wind Mapper

Wind Mapper is a mapping program created to display maps showing the locations of wind parks, turbines, and weather observation stations. Wind Mapper can display various map types, such as roadmaps, satellite imagery, and topographic maps. Its uses include the following:

- Identify terrain features near turbines that affect actual winds.

- Identify terrain features that influence weather forecast models.

- Identify weather-model forecast points useful for forecasting at a particular wind park.

2.1.4. Data Analysis

2.1.4.1. Power-Curve Development

The turbine manufacturer provided 80-m power curves initially used for the Elkhorn Valley wind park. However, forecasting winds with these power curves resulted in larger errors than expected; consequently, IPC built 10- and 80-m power curves for each site based on model wind forecasts and observed power. Building the power curve for each site also addressed air-density issues between sites, as the elevation of IPC's wind parks ranges from 2,800 to 4,800 feet.

Four 10- and 80-m power curves have been developed for the various wind parks. These consist of third and sixth-order equations. Since the development process used limited data (a few months) for many of the sites, the power curves should be revised as more data becomes available.

2.1.4.2. Wind-Rose Diagrams

Wind-rose diagrams were developed for each site to determine primary, secondary, and tertiary wind directions and associated wind speeds.

2.1.4.3. Terrain Analysis

Terrain ranges between very complex mountainous regions to flatter regions along the Snake River basin. Terrain analysis was primarily used to determine the best model point to use in the forecast at any particular site.

2.1.4.4. Power Patterns

An analysis of observed and forecasted wind speeds, as well as observed power, revealed several patterns that were useful in selecting forecast points and developing power-curve algorithms.

2.1.4.4.1. Day/Night Patterns

Generally, the most wind power is produced in the late afternoon as inversions are broken and full mixing of the atmosphere occurs.

2.1.4.4.2. Wind Directions

Winds moving up the valley (generally northwest) occur in the afternoon, and winds moving down the valley (southeast) occur at night.

2.1.4.4.3. Seasonality

The strength and time of the day of peak winds shifts seasonally.

2.1.4.5. High-Speed Cutouts

Wind turbines are turned off during high winds (referred to as a cutout) to prevent damage. Cutouts can result in large power drops, especially if many turbines are affected. A method was developed to alert users if high-speed wind cutouts are expected at a wind park by correlating observed turbine cutout data with forecasted wind speeds.

2.1.4.6. Maintenance Issues

Maintenance usually occurs daily at wind parks, with one or two turbines off-line. Some wind parks report turbine availability, while others do not. However, because of other errors associated with wind forecasting, a few turbines off-line did not greatly contribute to the overall margin of error. Other issues that can bring a whole or part of a wind park off-line, such as maintenance, can be addressed by the wind-park power forecast.

2.1.4.7. Geographic Dispersement of Power Production

Because the wind parks are spread out over 300 miles, error associated with the forecast of total wind is generally lower than for any individual wind park.

2.1.4.8. Regression Analysis

By using power curves, all 10- and 80-m wind forecasts are converted to power. Persistence and wind forecasts from the WRF-GFS, WRF-NAM, and RUC models are used as predictors. Using multiple linear regressions, correlation coefficients were developed for each predictor. The correlation coefficients can, and usually are, different for each wind park.
Regression equations were developed to use all available data to create a power forecast for the wind parks.

2.1.5. Forecast Development

2.1.5.1. Pre-Schedule Forecast

2.1.5.1.1. Data

The pre-schedule forecast uses the WRF-NAM through 72 hours and the WRF-GFS for forecasts out 5 days or more.

Persistence was tested as a predictor, but its contribution to the forecast was insignificant. Generally, the 10- and 80-m winds for the beginning and ending hour of the forecast were used as predictors. Some locations used 10- and 80-m winds for all forecast hours, while others used 10-m winds at night and 80-m winds during the day. The Elkhorn Valley wind park used different forecast points as a function of wind direction.

2.1.5.1.2. Accuracy

The two most used measures of accuracy during the development of pre-schedule and real-time forecasts were as follows:

1. **Mean absolute hourly error.** The mean absolute hourly error = ∑ the absolute value of (observed hourly power average – forecasted hourly power average)/the number of hours forecasted.

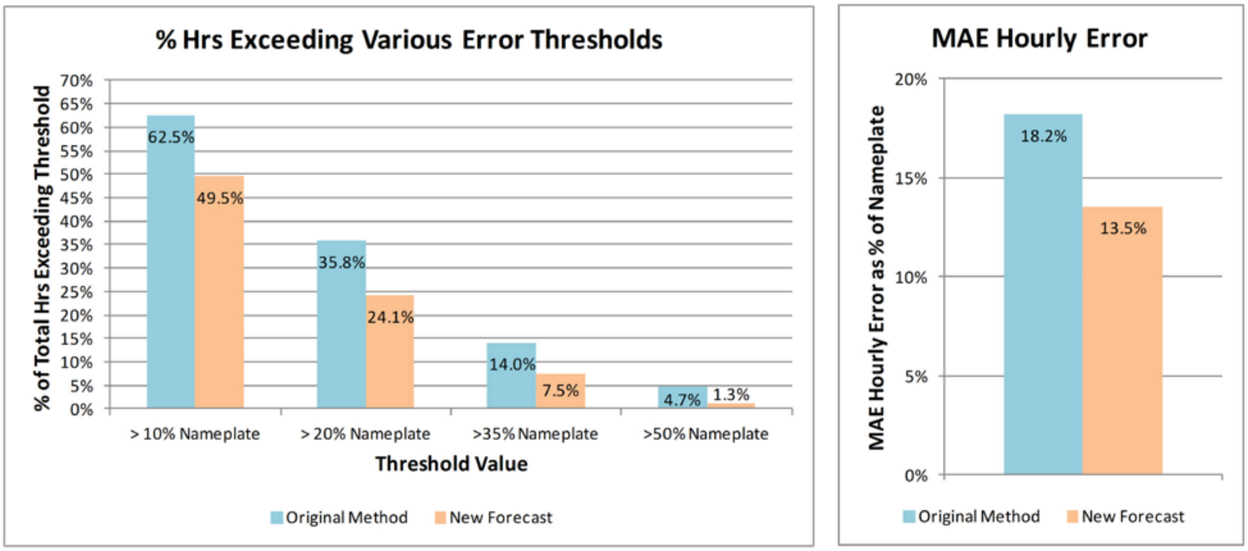
2. **Percent of hours exceeding a specific error threshold.** This measure calculates the percent of hours during a study period where the hourly error is greater than a specific percent of the capacity (i.e., how many times the forecast was off by 50% of capacity).

The mean absolute error (MAE) for all wind parks is about 13 percent (Figure 5). Large errors are mainly due to the timing of the model, although thunderstorm outflows are not well captured by the model.

The new pre-schedule forecast has resulted in the following:

- A significant reduction of the MAE over previous forecasting methods

- A considerable reduction in the number of times the hourly error is large



Original Method evaluated: 4/1/2011 – 10/19/2011 (Through end of use of original method)
New Forecast evaluated: 12/1/2011 – 6/30/2012 (Since full implementation of production forecast)

Original evaluation period includes entire summer season (calm weather) while new evaluation period does not.

Figure 5
Pre-schedule forecast errors

2.1.5.2. Real-Time Forecast

2.1.5.2.1. Data

Forecast details for hours one through six are as follows:

- **First-hour forecast.** If all data was available, this real-time forecast used seven predictors in the regression equation. The predictors included persistence from the previous hour and the model (WRF and RUC) forecast power based on 10- and 80-m wind forecasts for the beginning of the hour and the end of the hour.

- **Second-hour forecast.** This forecast used the same predictors as the first-hour forecast, except it used only the beginning hour forecast from the RUC model.

- **Third- through sixth-hour forecasts.** This forecast used persistence and the WRF beginning- and ending-hour data.

Occasionally, some data may be missing. The program is flexible enough to use a limited set of predictors, older model data, and WRF-GFS data.

2.1.5.2.2. Accuracy

The new real-time forecast has resulted in the following:

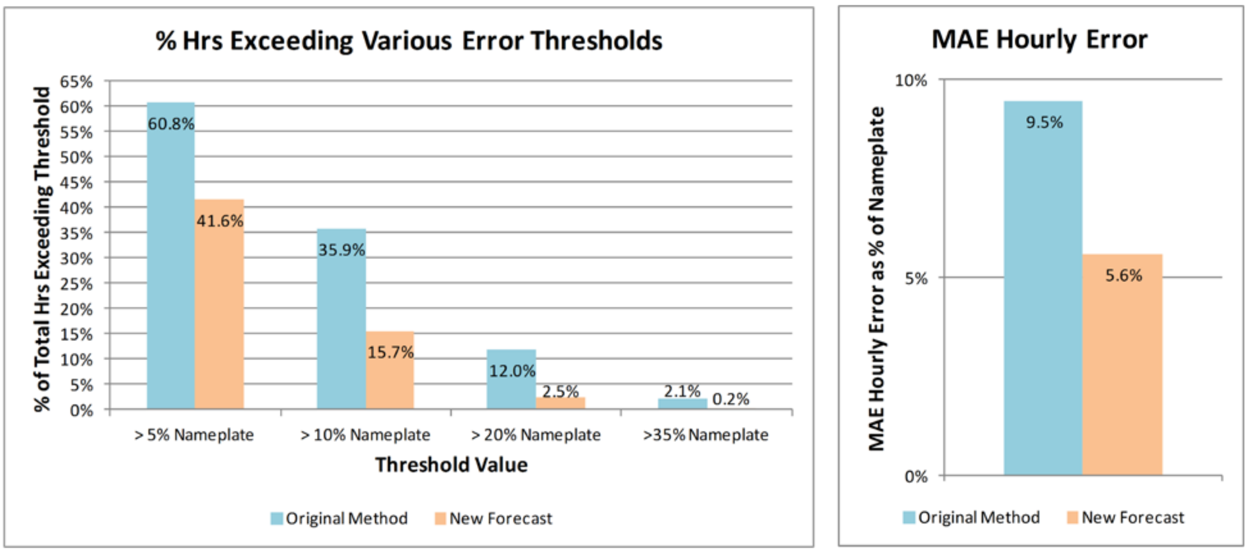
- A reduction in the MAE of approximately 40 percent.

- A drastic reduction in the number of times the hourly error is large.

Figure 6 shows the increase in accuracy over the original method (using the observed generation at the top of the hour).

Figure 7 and Table 1 show the accuracy of the real-time forecast compared to using persistence as a forecast for various wind-park groupings. Progressing from left to right, the error of using persistence for forecasting within the hour is lower than that of the real-time forecast.

Figure 8 displays another study period showing the accuracy of the real-time forecast compared to using persistence as a predictor of future generations.



Evaluation Period: 12/15/2011 – 6/30/2012 (Since full implementation of production forecast)

Original Method = Persistence at top of the hour (Ex: Power @ 2pm forecasts period of 3-4pm)

Figure 6
Real-time forecast errors

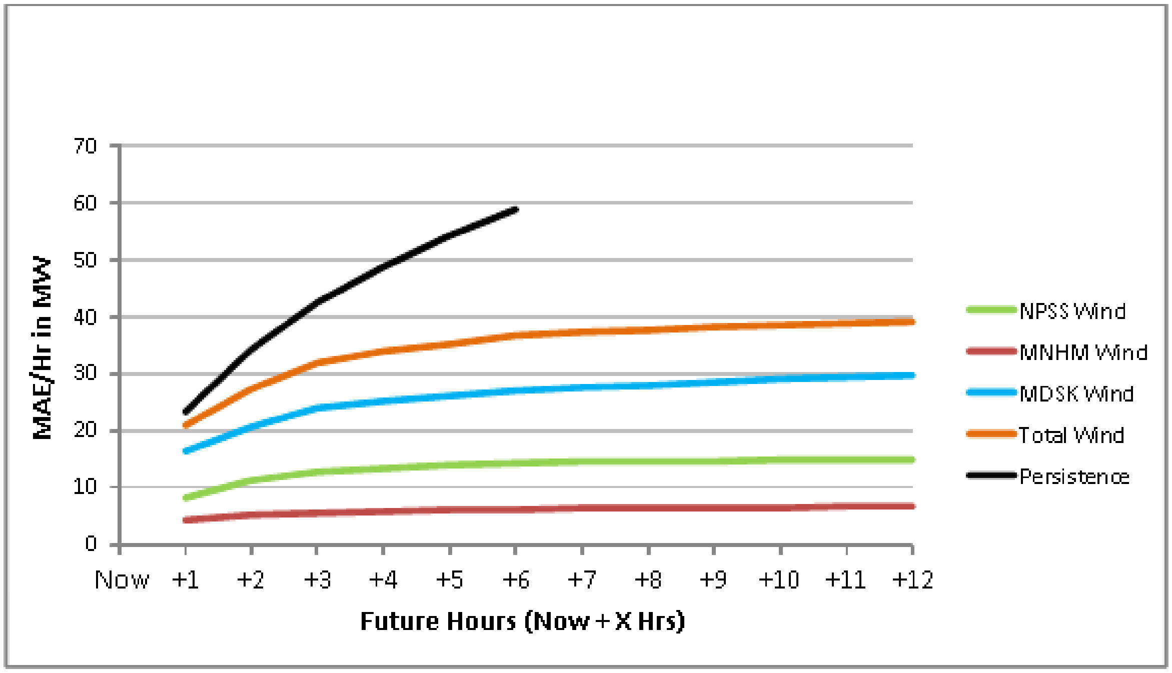


Figure 7
Real-time forecast accuracy versus hours into the future: May 10–September 15

Table 1
Real-time forecast accuracy versus hours into the future: May 10–September 15

	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12
NPSS Wind	8.3	11.4	12.7	13.6	14.1	14.4	14.6	14.7	14.8	14.9	15.0	15.0
MNHM Wind	4.3	5.3	5.7	6.0	6.2	6.3	6.4	6.5	6.5	6.6	6.7	6.7
MDSK Wind	16.4	20.8	23.9	25.3	26.2	27.1	27.6	28.1	28.6	29.0	29.4	29.8
Total Wind	21.1	27.4	31.8	33.9	35.2	36.6	37.2	37.6	38.1	38.5	38.9	39.2
Persistence	23.4	34.2	42.4	48.7	54.1	58.6	–	–	–	–	–	–

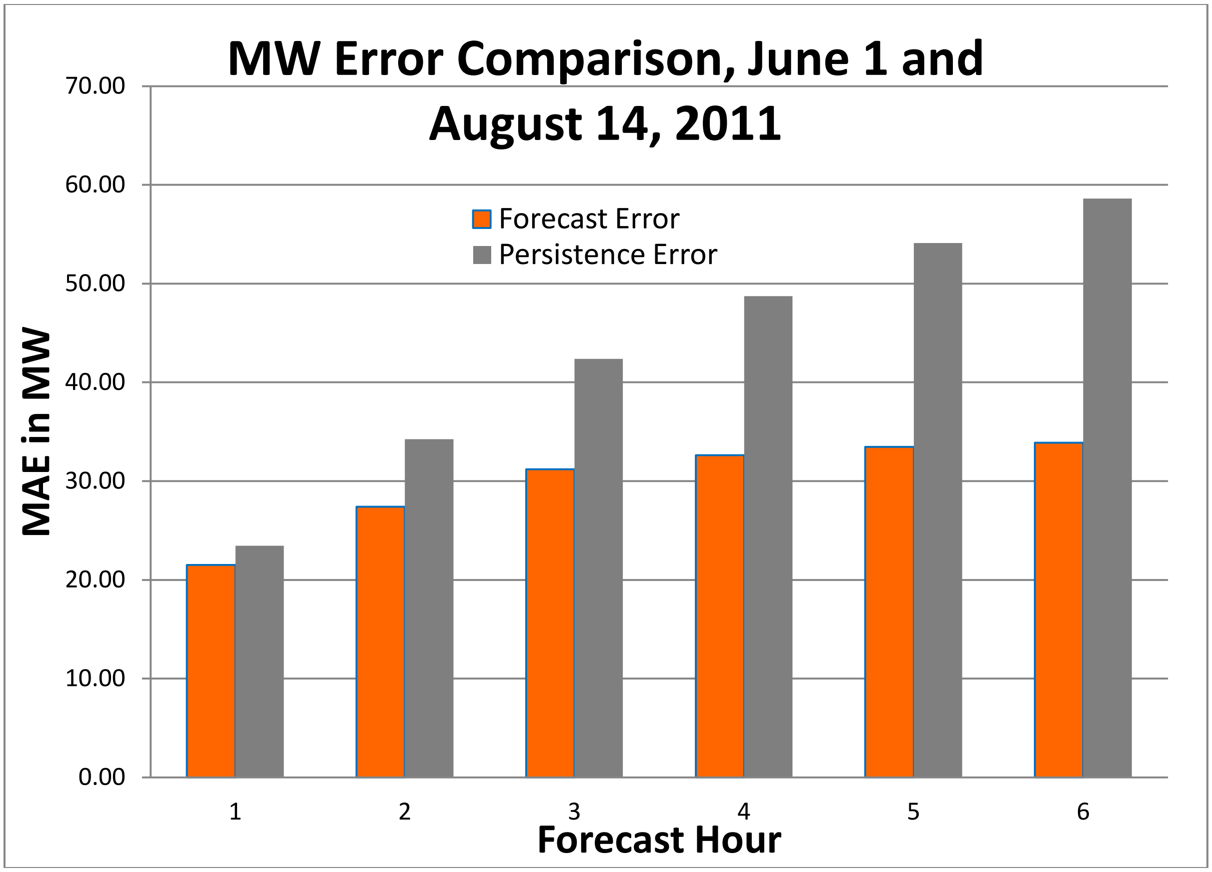


Figure 8
MW error comparison: June 1 and August 14, 2011

2.1.5.3. 30/60-Minute Rolling Forecast

IPC attempted to develop a wind-generation forecast for 30 and 60 minutes into the future. This forecast would be updated every five minutes. Current generation values—the slope of recent generation changes and weather forecast data—were incorporated to predict generation 30 and 60 minutes out. Methods tested to incorporate recent generation changes included the following:

- Using the most recent 5-, 10-, 30-, 60-, and 90-minute averages of generation
- Using a slope determined by the two most recent 5-, 10-, 15-, 30-, 60-, and 90-minute averages of generation
- Limiting the amount a slope could change the current generation value by 10, 50, or 100 percent of the current generation value
- Limiting the amount a slope could change the current generation value by 10 or 50 percent of the maximum generation possible

Incorporating weather data resulted in the following:

- An average absolute hourly error of 2 to 3 MW worse on a 30-minute forecast using existing real-time forecast data versus a 10-minute average of generation.
- An improvement of 3 MW hourly error over a 10-minute persistence method at Bell Rapids (100-MW capacity) by incorporating a simplified hour-ahead weather forecast for a study period of June 2011 to September 2011.
- A reduction in the number of large hourly errors at Bell Rapids (370 occurrences of error > 25 MW using simplified hour-ahead weather forecast versus 420 using a 10-minute persistence method) for a 30-minute-ahead forecast. Also, the number of 50+ MW errors was reduced from 44 to 34.

IPC briefly investigated whether curve fitting could be used, but this revealed no significant outcome.

Tables 2 and 3 show sample results from the 30- and 60-minute forecast studies. In this particular attempt, the use of a 10-minute generation average was more accurate than all but one of the other attempted methods and had the added advantage of using a simpler calculation.

Table 2
Thirty-minute forecast study (maximum generation approximately 490 MW)

Results					Forecast Method	
Average Absolute Error (MW)	**Number of Hours with 50+ MW Errors**	**Percent of Hours with 50+ MW Errors**	**Number of Hours with 100+ MW Errors**	**Percent of Hours with 100+ MW Errors**	**Slopes Based on Two Consecutive Period Averages of Generation**	**Max. Influence by Slope Limited to:**
17.0	564.0	5.8	42.0	0.4	5-minute periods	100% of persistence or 50% of nameplate
16.7	559.0	5.7	44.0	0.5	10-minute periods	No limit on slope influence
13.4	284.0	2.9	26.0	0.3	10-minute periods	10% of persistence or 10% of nameplate
15.1	396.0	4.1	27.0	0.3	15-minute periods	50% of persistence or 50% of nameplate
16.7	558.0	5.7	44.0	0.5	30-minute periods	100% of persistence or 50% of nameplate
18.2	701.0	7.2	72.0	0.7	60-minute periods	100% of persistence or 50% of nameplate
19.5	837.0	8.6%	75.0	0.8	90-minute periods	100% of persistence or 50% of nameplate
13.6	314.0	3.2	27.0	0.3	10-minute persistence—no slope	–

Table 3
Sixty-minute forecast study (maximum generation approximately 490 MW)

Results					Forecast Method	
Average Absolute Error (MW)	**Number of Hours with 50+ MW Errors**	**Percent of Hours with 50+ MW Errors**	**Number of Hours with 100+ MW Errors**	**Percent of Hours with 100+ MW Errors**	**Slopes Based on Two Consecutive Period Averages of Generation**	**Max. Influence by Slope Limited to:**
24.8	1,392.0	14.2	190.0	1.9	30-minute periods	100% of persistence or 50% of nameplate
25.0	1,411.0	14.4	212.0	2.2	60-minute periods	100% of persistence or 50% of nameplate
20.7	947.0	**9.7**	114.0	**1.2**	10-minute persistence—no slope	

The final outcome for the 30/60-minute rolling forecast was using the average of the last 5 minutes of generation to predict generation 30 and 60 minutes later.

IPC's overall assessment is that it should be possible to make small improvements in the accuracy of various measures for 30- and 60-minute-ahead forecasts (over a persistence-based method), but the complexity of achieving such improvements is high.

2.1.5.4. High-Speed Cutout Forecast

The high-speed cutout forecast was created to predict when turbines may be shut down to protect against physical damages during high-wind-speed events. An analysis of existing data showed that only two wind parks experienced enough of these events to provide a significant amount of data for analysis. The Elkhorn and Rockland wind parks were used to develop the methodology. As more cutout data becomes available and as other wind parks come on-line, the data should be re-analyzed to determine if the forecast can be applied at other parks and if the accuracy of the Elkhorn and Rockland forecasts can be improved.

2.1.5.4.1. Accuracy

A study of the high-speed cutout forecast for the Rockland wind park from January 1, 2012, to September 22, 2012, revealed the following:

- When the forecast indicated yellow or red conditions, an actual turbine-out event occurred within the next 3 hours 27.1 percent of the time.
- When actual turbine-out events occurred, the forecast warned of the possibility 78 percent of the time.
- For the Rockland wind park, there is a high false-forecast rate, but when events do occur, the forecast provides warning 78 percent of the time.

A study of the high-speed cutout forecast for the Elkhorn wind park from April 1, 2011, to September 22, 2012, revealed the following:

- When the forecast indicated yellow or red conditions, an actual turbine-out event occurred within the next 3 hours 62.1 percent of the time.
- When actual turbine-out events occurred, the forecast warned of the possibility 83 percent of the time.
- For the Elkhorn wind park, the forecast quality is significantly higher than for the Rockland wind park. However, this is not unexpected given the significantly higher amount of data available from Elkhorn for the development of the forecast versus Rockland's limited set of data.

Figures 9 and 10 are graphical representations of the study periods for the Rockland and Elkhorn wind parks. Bars in the negative y direction indicate forecasted yellow/red conditions, and green bars in the positive y direction indicate actual turbine outages. The y values are based on the average number of turbines out for a given hour period but are binned in groups of 0 to 5, 5.1 to 10, etc., to make the display readable.

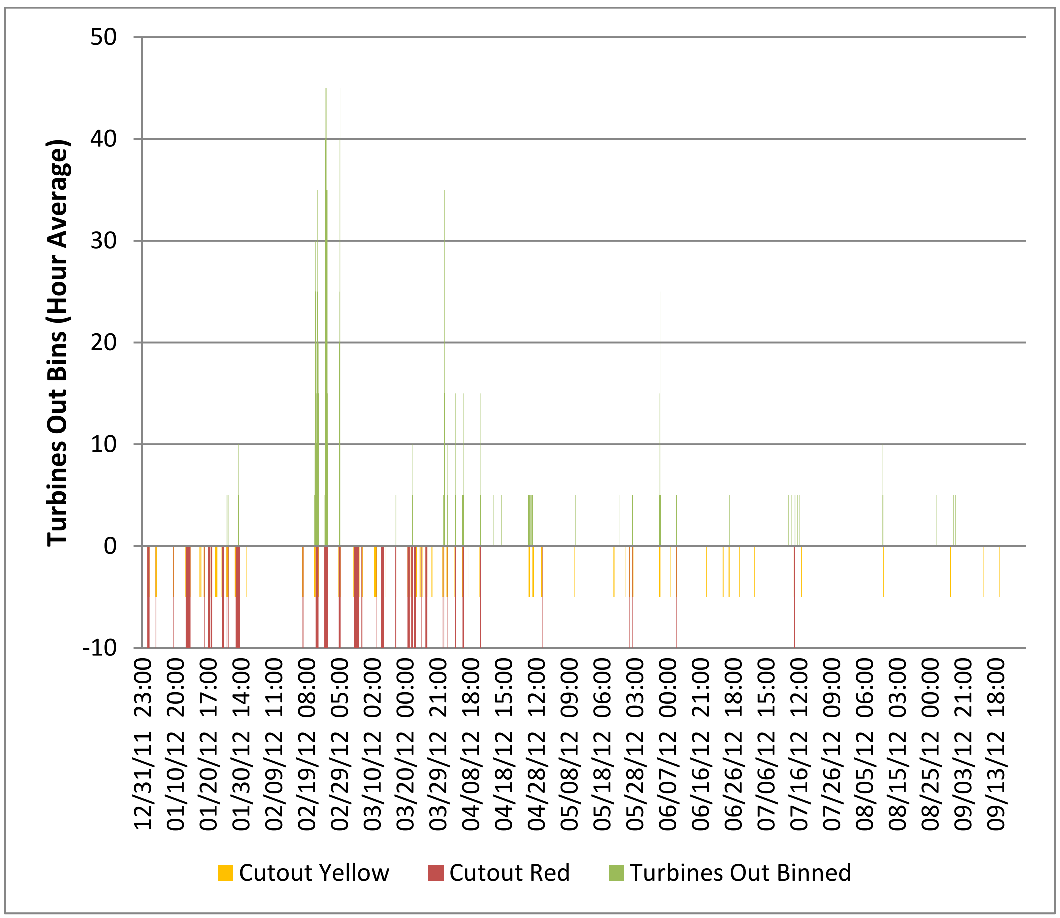


Figure 9
Rockland wind-park high-speed cutout forecast

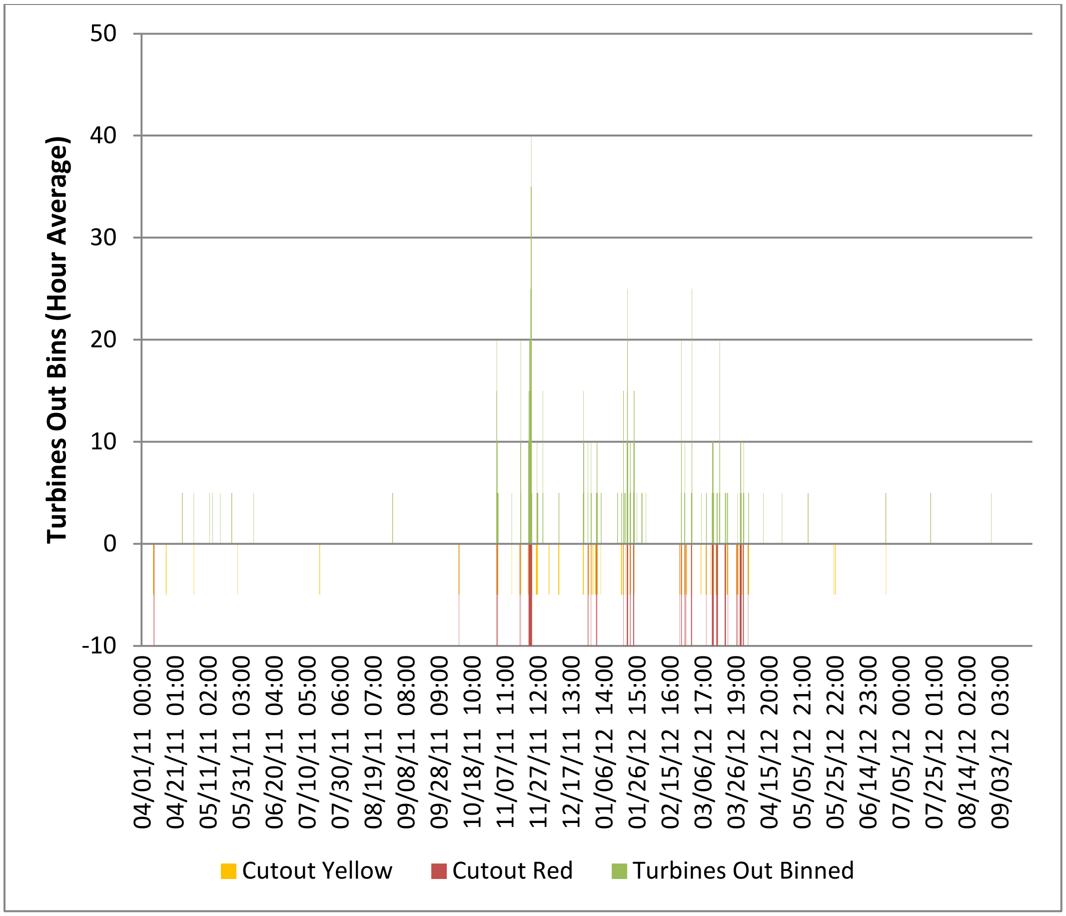


Figure 10
Elkhorn wind-park high-speed cutout forecast

2.1.6. System Design

2.1.6.1. Wind-Generation Forecast Tool

Figure 11 is a design diagram of the wind-generation forecast tool.

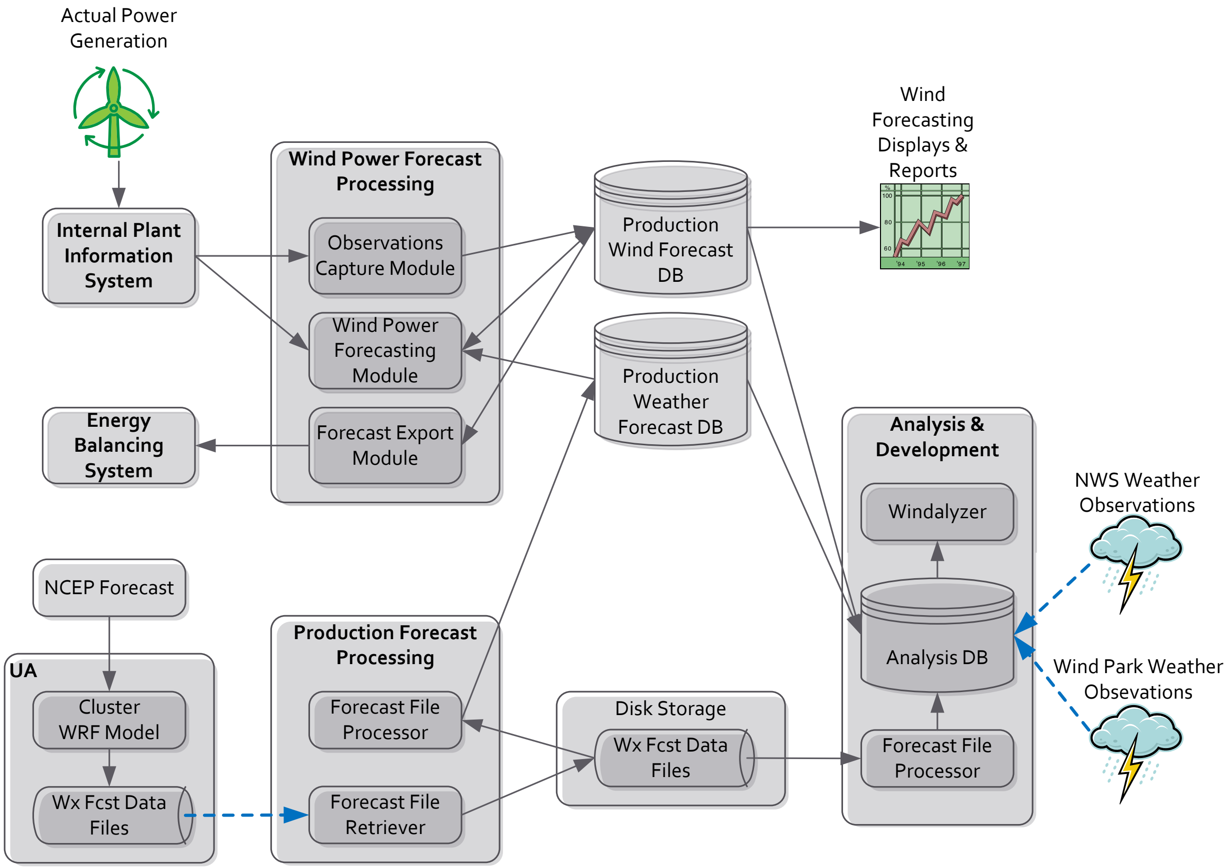


Figure 11
Design diagram

2.1.6.2. Pre-Schedule Wind-Generation Forecast Display

The pre-schedule wind-generation forecast displays the following information:

- Full days (single or multiple)
- Data for a single wind park or multiple wind parks rolled into various groupings
- Hourly information
  - A pre-schedule calculation forecasted one or more days out (graph)
  - Actual wind-power generation (graph)
  - Older forecasting methods for comparison (graph)
  - Hourly data and variance information (table)
- Park and area information

- Contributions of individual parks or areas to the total forecast and observed wind-power generation (graph)

- Variances of individual parks or areas that contribute to the total variance (graph)

- Accuracy metrics
- Screenshots (see figures 12 and 13 for examples)

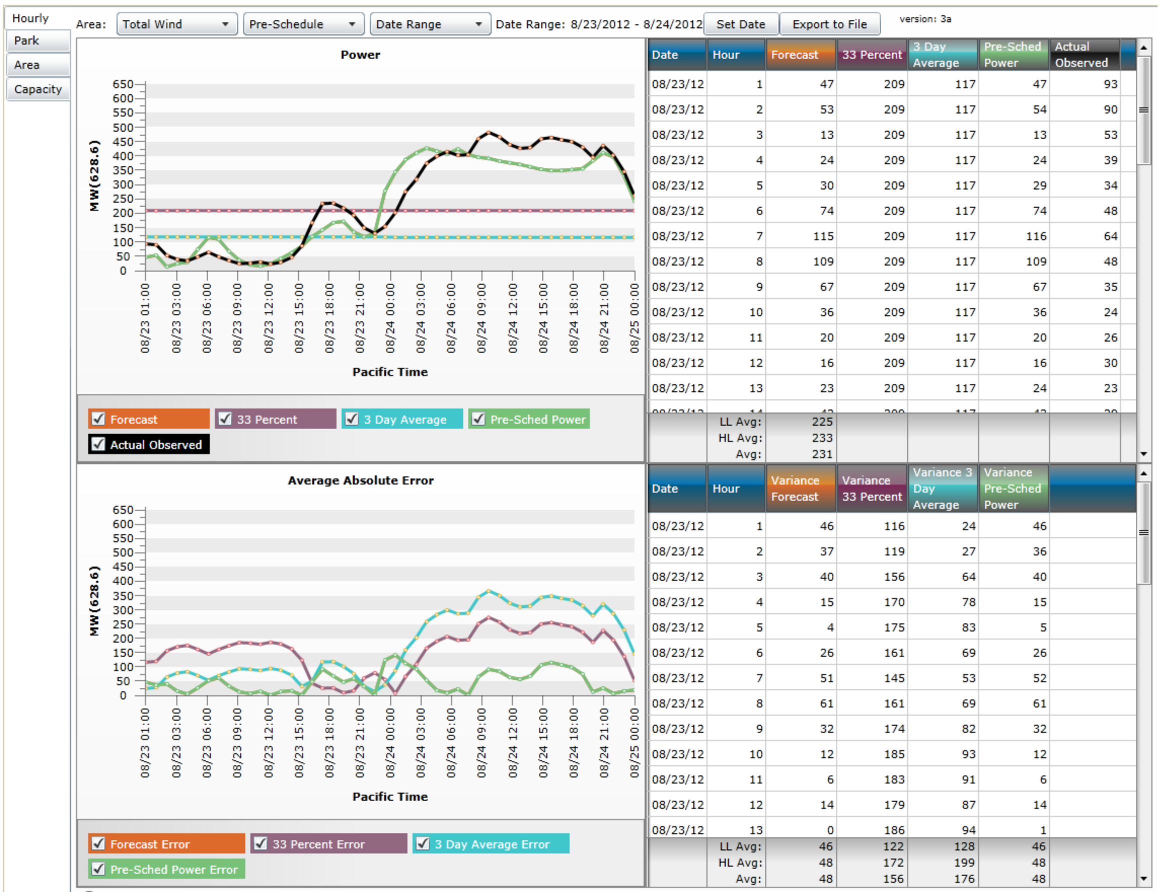


Figure 12
Main screen of the pre-schedule forecast display showing new and previous forecast curves for comparison in the top graph and table and hourly error values in the bottom graph and table

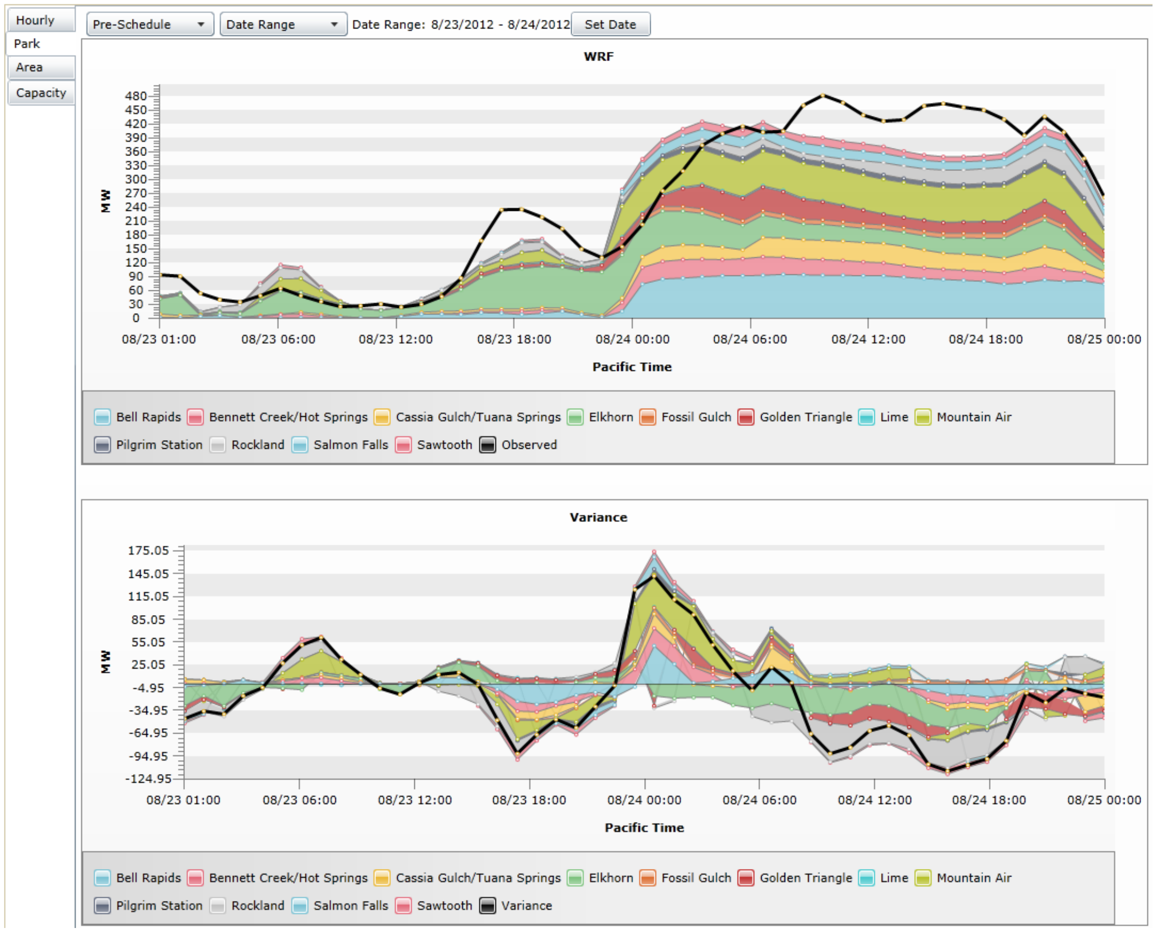


Figure 13
Park screen showing stacked contributions of individual wind parks to the total forecast in the top graph and stacked hourly error contributions in the bottom graph

2.1.6.3. Real-Time Wind-Generation Forecast Display

The real-time wind-generation forecast displays the following information:

- Hourly data for up to 42 hours
- Data for a single wind park or multiple wind parks rolled into various groupings
- Hourly information
  - A pre-schedule calculation forecasted one or more days out (graph)
  - Hourly calculations forecasted up to 12 hours out (graph)
  - Actual wind-power generation (graph)
  - Hourly data and variance information (table)

- Park and area information
    - Contributions of individual parks or areas to the total forecast and observed wind-power generation (graph)
    - Variances of individual parks or areas that contribute to the total variance (graph)
- Map
    - A quick overview of conditions across all wind parks
    - Sparklines show six hours of past forecast and observed generation plus three hours of future forecast
- Cutout information
    - The probability of turbines experiencing high-speed cutout conditions at individual parks
- Accuracy metrics
- Screenshots (see figures 14, 15, and 16 for examples)

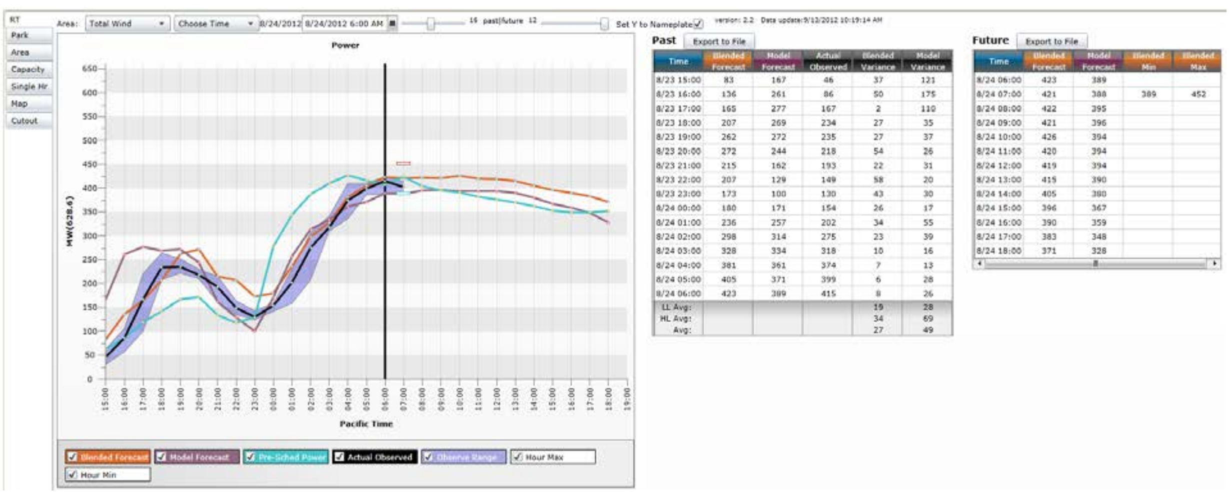


Figure 14
Main screen of the real-time forecast display

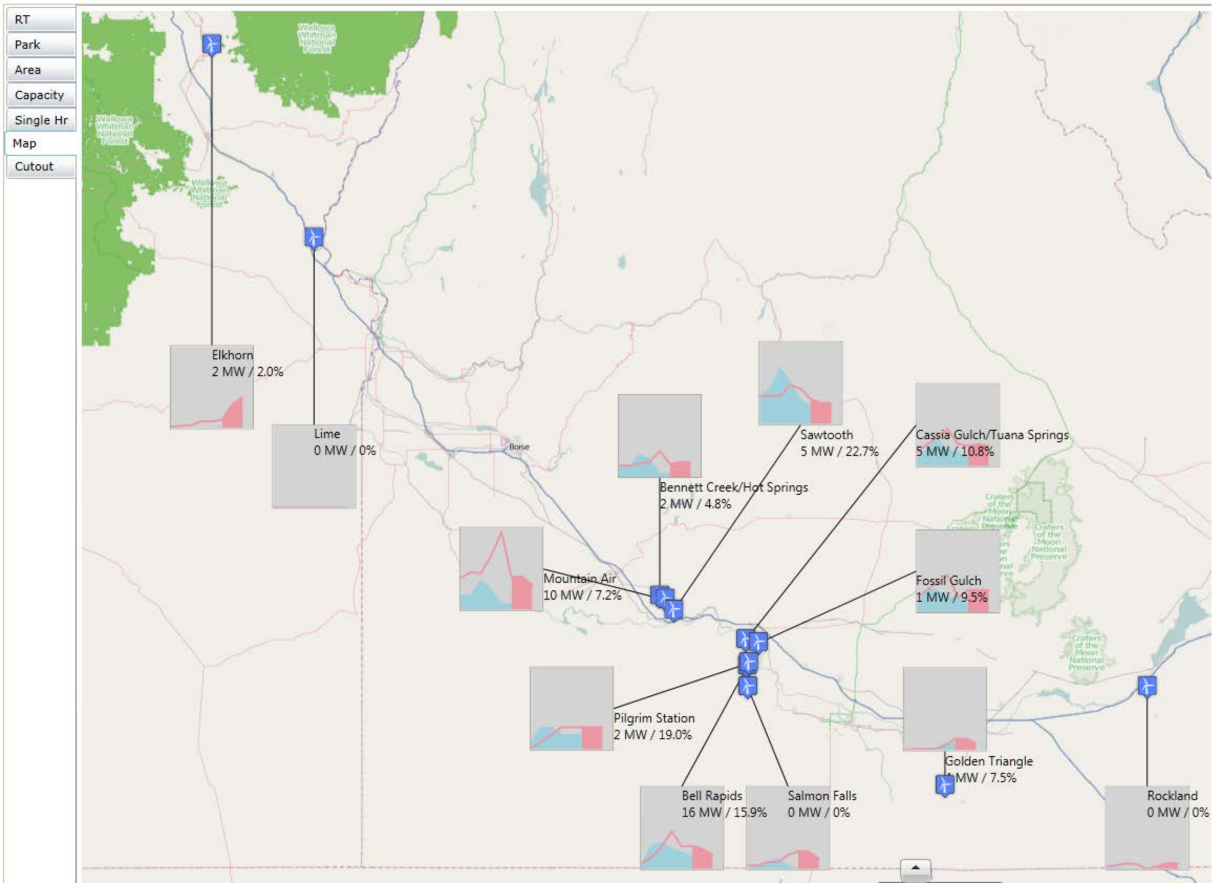


Figure 15
Map portion of the real-time forecast display

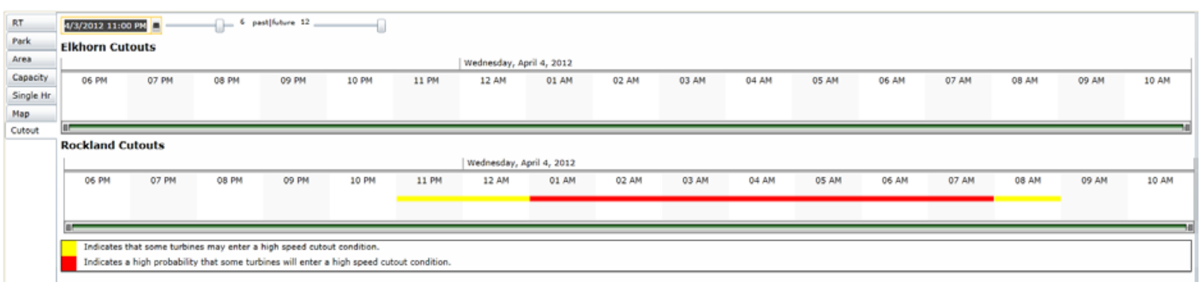


Figure 16
High-speed cutout forecast portion of the real-time forecast display

2.1.6.4. 30/60-Minute Rolling Wind-Generation Forecast

The 30/60-minute rolling wind-generation forecast was meant to display values for 30 and 60 minutes into the future, as well as hourly real-time wind-generation forecasts, short-term load forecasts, and observed wind-generation at 5-minute intervals.

During the development of the 30- and 60-minute forecast algorithms, IPC discovered that combining currently available weather forecast data with observed wind generation did not have any noticeable improvement in accuracy over using persistence as a 30- and 60-minute generation predictor. Because current generation is available in other existing displays, the main purpose for this display was invalidated. The value of displaying short-term load-forecast data alongside wind forecast data is still undetermined.

The rolling wind-generation forecast displays the following information:

- Hourly forecast data for up to 42 hours
- Short-term load forecasted 15, 30, 45, and 60 minutes into the future
- Observed wind-power generation every five minutes
- Data for a single wind park or multiple wind parks rolled into various groupings
- Accuracy metrics
- Screenshots (see Figure 17 for an example)

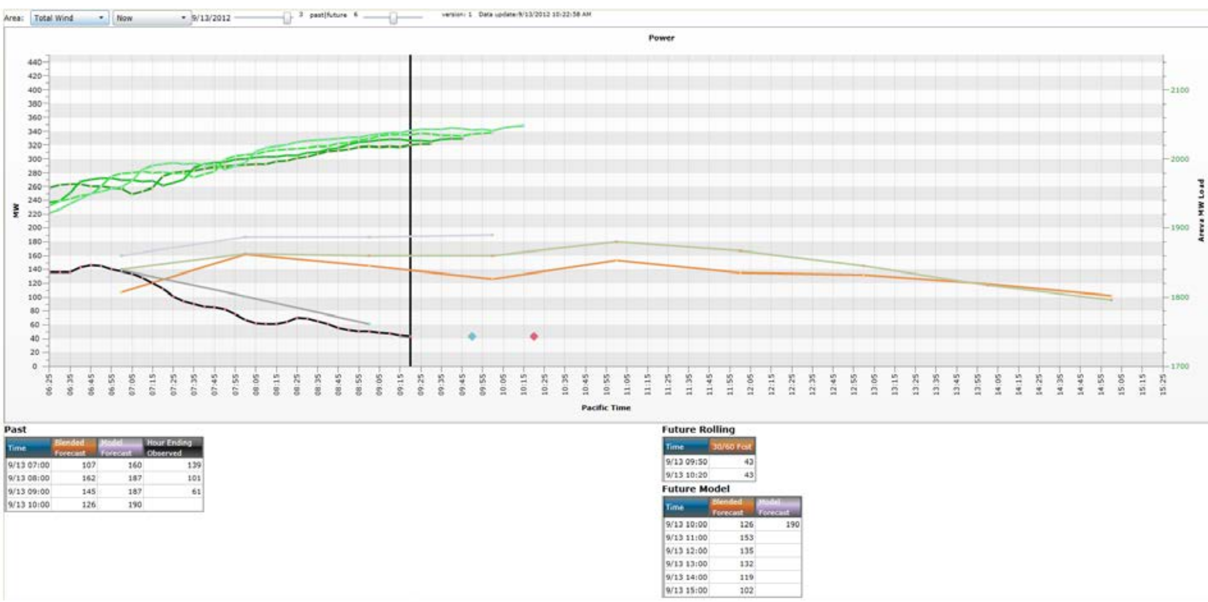


Figure 17
Proposed display for the rolling 30/60-minute ahead forecast.

2.2. Demand Forecast

2.2.1. Leveraging Existing Tools

The project implemented IPC's Energy Management System (EMS) vendor short-term load forecast, which provides a high-frequency refresh rate that allows for a more accurate demand forecast. The software module was a component of an existing tool already owned by IPC, but it had never been implemented due to a lack of resources. The tool provides demand-forecast values for every five-minute interval for zero to four hours into the future and is refreshed every five minutes. The ability to refresh at a more frequent interval allows the model to be more accurate, as it can take into account real-time weather and load data into each refreshed forecast.

2.2.2. Data Used

The equations within the tool are proprietary, but the main inputs are historical-load data, current load, and forecasted temperatures.

2.2.3. Configuration of the Tool

Although the tool was part of an existing licensed software, when the load-forecast configuration began, IPC discovered the tool had not been fully developed to be operational for the IPC usage model. There were 22 issues, of which 15 were system problem report (SPR)-type related items and 7 were database configuration items. IPC worked with the software provider to identify and resolve the issues, which lead to the enhancement of the load-forecast product.

2.2.4. Accuracy

The mean average percentage errors (MAPE) were as follows:

- 5-minute MAPE percent → 0.32 percent for a 12-day history
- 10-minute MAPE percent → 0.58 percent for a 1-day history
- 30-minute MAPE percent → 0.81 percent for a 1-day history
- 60-minute MAPE percent → 1.95 percent for a 1-day history

Figure 18 is a snapshot of the load-forecast history for 10, 30, and 60 minutes versus the actual area load.

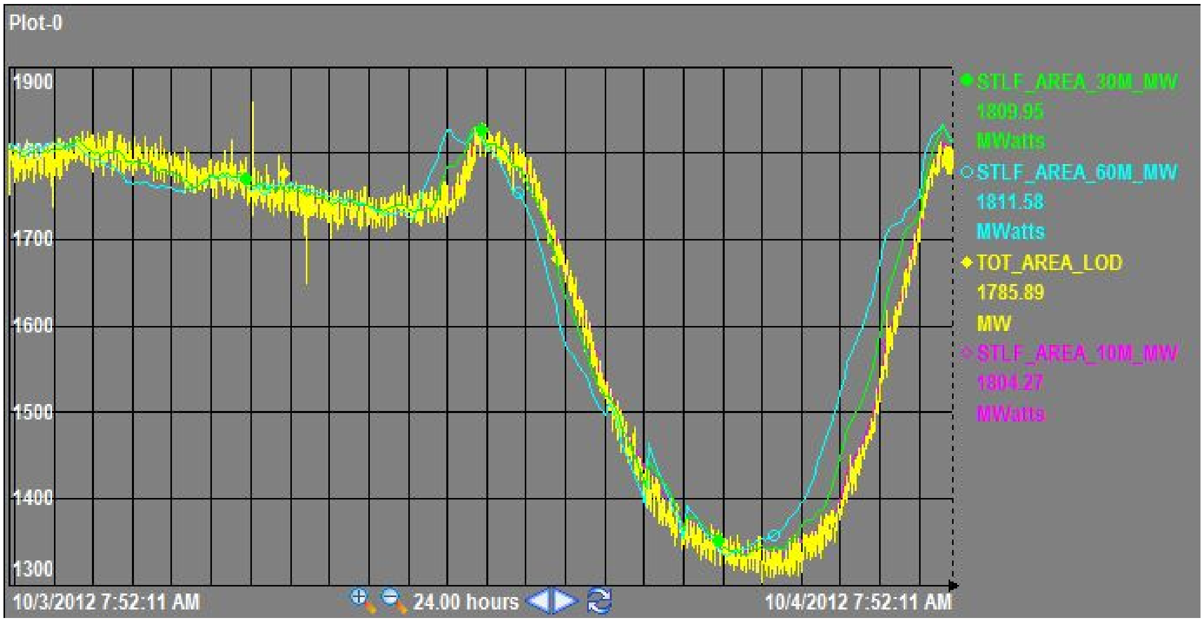
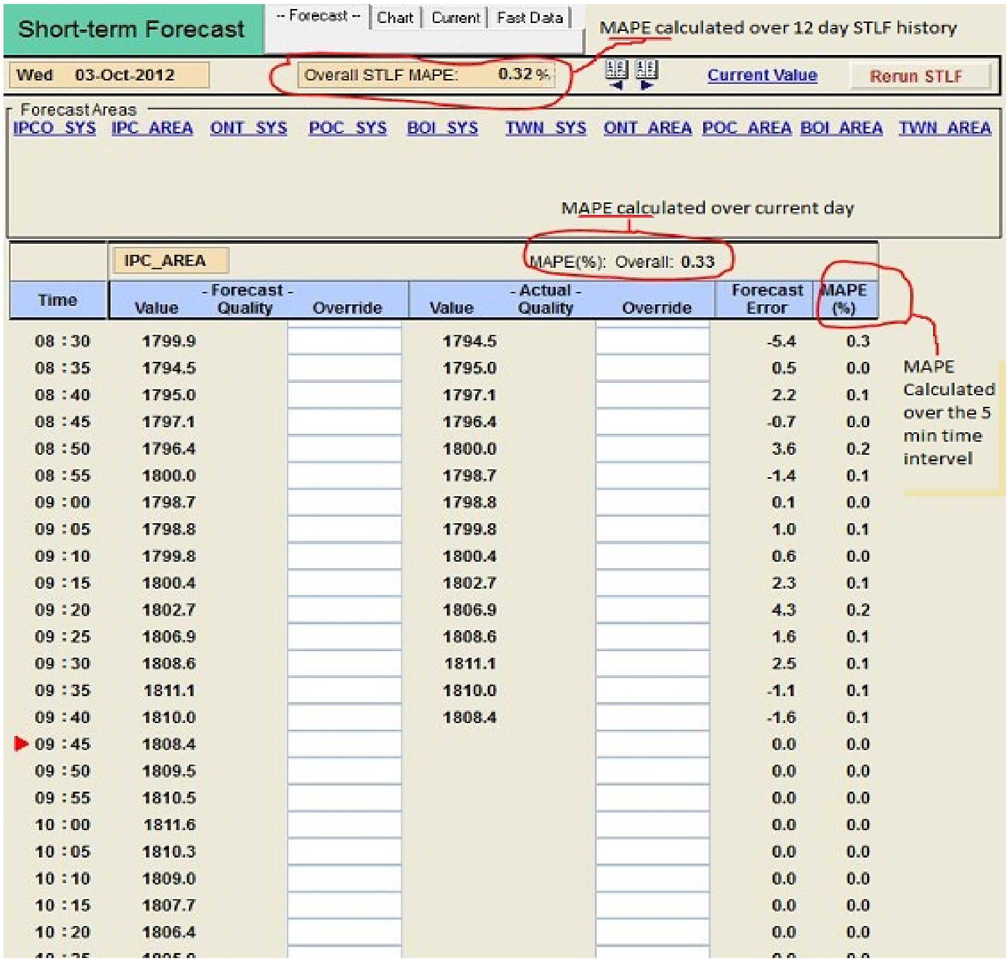


Figure 18
Example screenshot

2.2.5. Short-Term Demand Load Forecast

The short-term load forecast (Figure 19) displays the following information:

- Five-minute forecast versus actual values
- IPC_AREA load as the selected forecast area
- The various MAPE calculations (circled in red)



Time	Forecast Value	Forecast Quality	Forecast Override	Actual Value	Actual Quality	Actual Override	Forecast Error	MAPE (%)
08 :30	1799.9			1794.5			-5.4	0.3
08 :35	1794.5			1795.0			0.5	0.0
08 :40	1795.0			1797.1			2.2	0.1
08 :45	1797.1			1796.4			-0.7	0.0
08 :50	1796.4			1800.0			3.6	0.2
08 :55	1800.0			1798.7			-1.4	0.1
09 :00	1798.7			1798.8			0.1	0.0
09 :05	1798.8			1799.8			1.0	0.1
09 :10	1799.8			1800.4			0.6	0.0
09 :15	1800.4			1802.7			2.3	0.1
09 :20	1802.7			1806.9			4.3	0.2
09 :25	1806.9			1808.6			1.6	0.1
09 :30	1808.6			1811.1			2.5	0.1
09 :35	1811.1			1810.0			-1.1	0.1
09 :40	1810.0			1808.4			-1.6	0.1
09 :45	1808.4						0.0	0.0
09 :50	1809.5						0.0	0.0
09 :55	1810.5						0.0	0.0
10 :00	1811.6						0.0	0.0
10 :05	1810.3						0.0	0.0
10 :10	1809.0						0.0	0.0
10 :15	1807.7						0.0	0.0
10 :20	1806.4						0.0	0.0

Figure 19
Short-term load forecast MAPE values

2.2.6. Short-Term Demand Forecast Display

The short-term demand forecast graphical screenshot (Figure 20) displays the following information:

- Forecast areas—IPC_AREA LOAD selected
- Short-term demand forecast values out to four hours ahead
- Daily plot of actual load versus forecasted load in five-minute increments

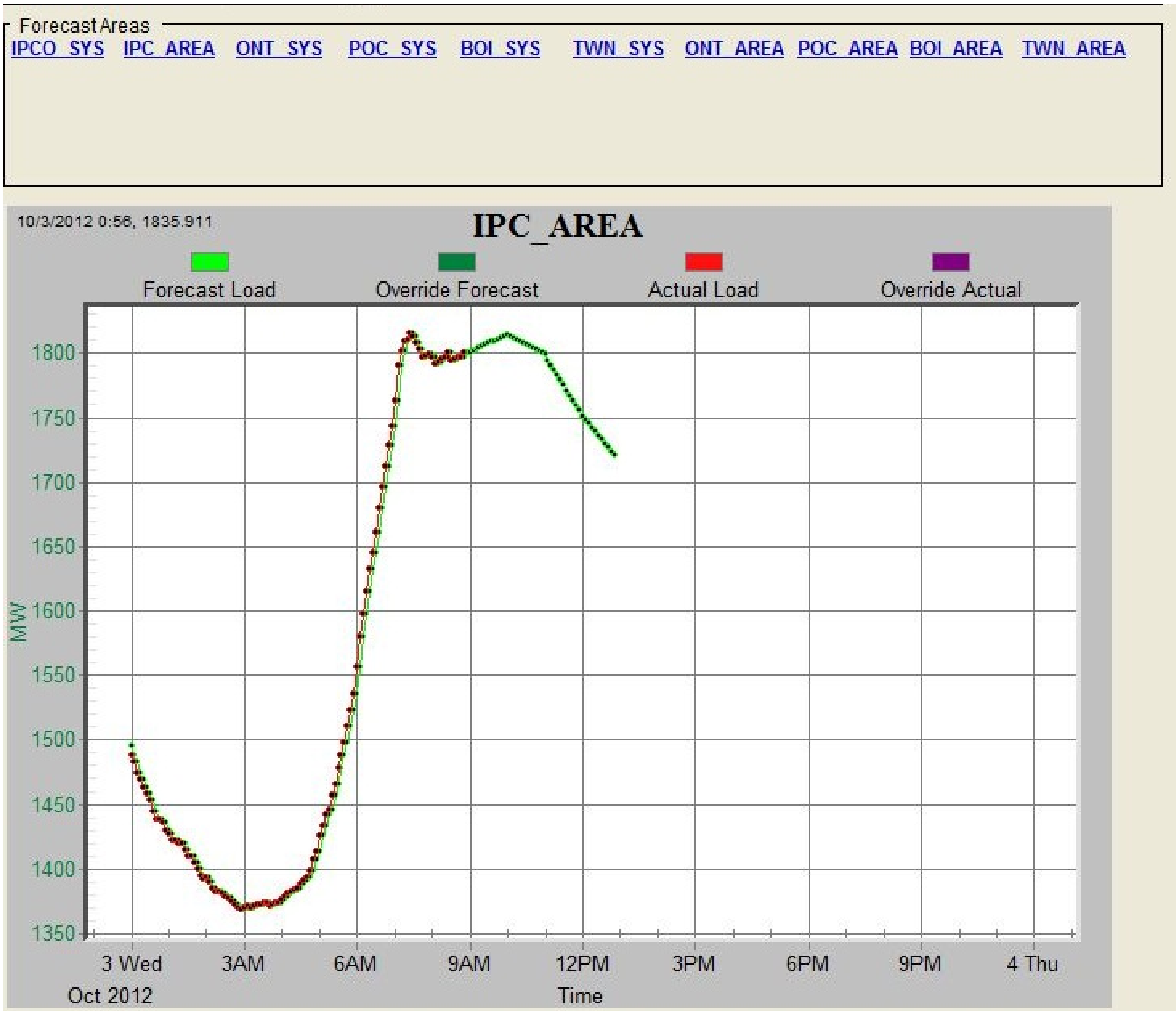


Figure 20
Short-term demand forecast graphical screenshot

2.2.7. Additional Benefit—Mid-Term Demand Forecast

As part of implementing the demand forecast tool, IPC also configured the mid-term demand forecast module, which provides forecast values for hourly intervals for 30 days into the future and is refreshed hourly. The tool is under evaluation to determine if a recommendation can be made to replace the manually intensive pre-schedule demand forecast used currently.

2.3. Regulating Margin Forecast

2.3.1. Summary

The implementation of the short-term demand forecast enabled the calculation of the regulating margin forecast to be based on 10- and 60-minute forecasted values. Prior to the tool, the regulating margin forecast was based on 1 percent of the load value. Enhancing the regulating margin forecast provides a more accurate idea of where the balance of the system will be in 10 and 60 minutes, which allows operators to proactively balance the system.

2.3.2. Calculation

The calculations for deriving the 10- and 60-minute expected regulation margins are the same, with the exception of the time period: wind regulation obligation + 10 or 60-minute ramp change + (projected load 10 or 60 minutes − actual load) = 10- or 60-minute expected regulating margin.

The reserve status forecast (Figure 21) displays the following information:

- Ten-minute regulating margin (circled in blue)
- Sixty-minute regulating margin (circled in red)
- General calculations for IPC's regulating reserves

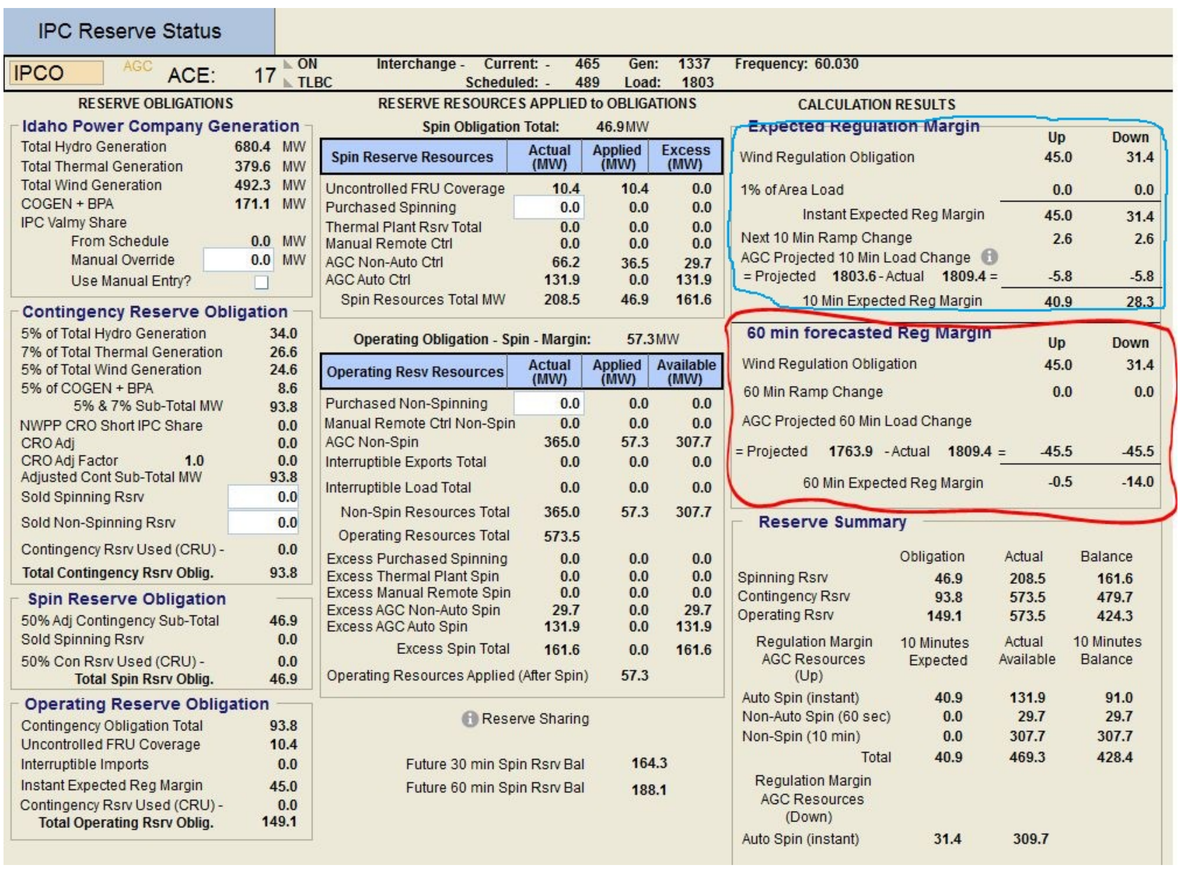


Figure 21
Ten- and sixty-minute regulating margins

2.4. Spinning Reserve Forecast

2.4.1. Summary

The implementation of the short-term demand forecast enabled calculations based on it to generate a 30- and 60-minute spinning reserve forecast. IPC aimed to develop a tool to consolidate the wind MW forecast and short-term load forecasts to derive a more accurate estimate of the required reserve needed for wind variations.

2.4.2. Display

The spinning reserve forecast (Figure 22) displays the following information:

- Spinning reserve 30/60-minute current and balance (circled in red)

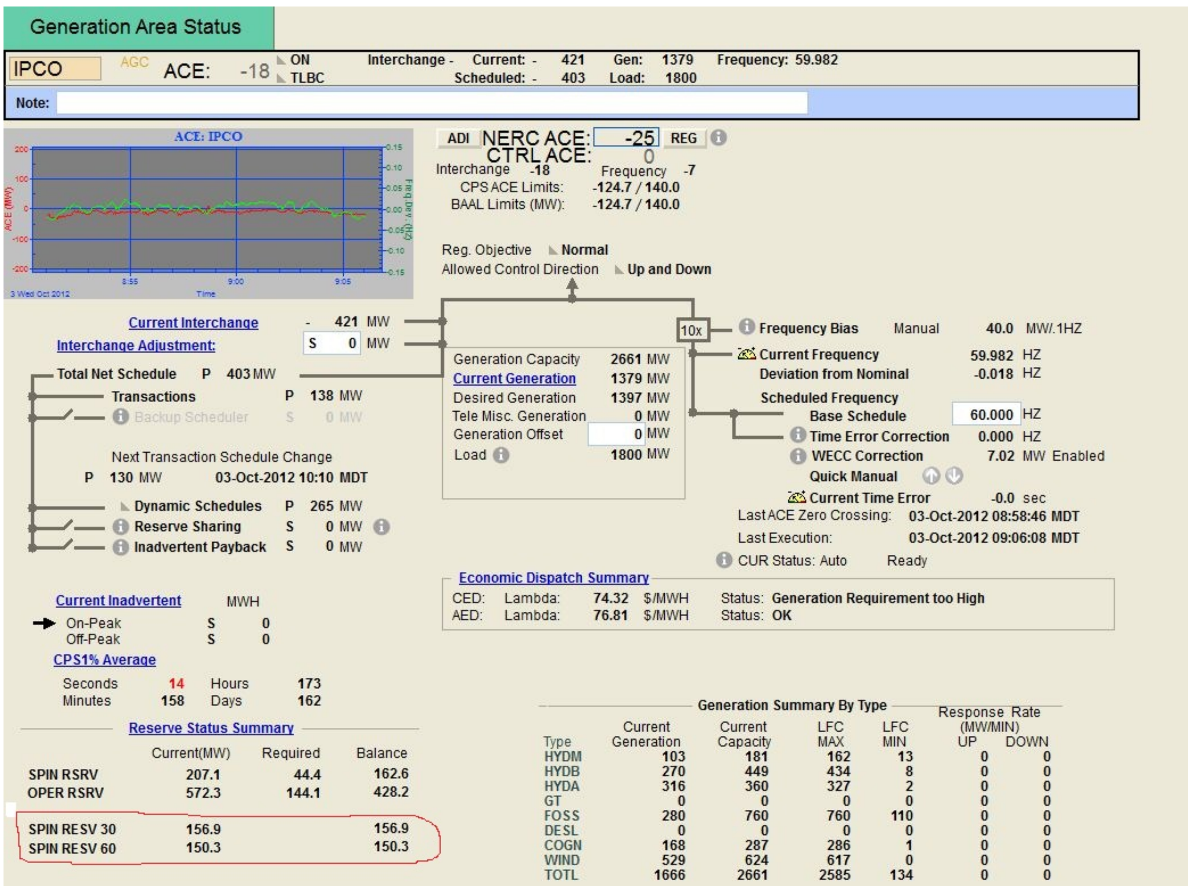


Figure 22
Spinning reserve 30/60-minute forecast

3. SUMMARY OF RESULTS

3.1. Evolution of the Scope

The initial plan for the RIT project was to purchase an off-the-shelf variable generation balancing tool that required an external wind forecast. However, IPC determined that an internally produced forecast was more accurate than third-party forecasts. After discussing options with other utilities and research facilities, IPC created its own forecast tool using WRF data from the UA.

3.2. Forecasts

Overall, IPC developed tools to more accurately forecast variable generation and demand to operate the system in a safe, economical, and reliable manner.

3.2.1. Pre-Schedule and Real-Time Forecasts

The pre-schedule and real-time forecasts were successfully implemented and are providing forecast values that more accurately predict wind generation.

3.2.2. 30/60-Minute Rolling Forecast

After analyzing the forecasts created, IPC determined that the one-hour wind forecast was unable to forecast more accurately than persistence without large additional effort. Slope projections of various time durations and spacings were tried but were unsuccessful. An option for the future may be curve fitting.

3.2.3. Short-Term Demand Forecast

The short-term demand forecast was successfully implemented and is providing forecast values at intervals not previously available.

3.2.4. Regulating Margin and Spinning Reserve Forecasts

Calculations for the regulating margin and spinning reserve forecasts were implemented that incorporated the more accurate short-term demand forecast; however, because efforts to develop a wind forecast for intervals of less than one hour were unsuccessful in improving on persistence, the full capabilities of this tool were not realized. If a short-term wind forecast is developed in the future, this tool is already in place, so the value can easily be incorporated into the equation.

3.3. Challenges

The following were determined significant challenges to the project:

- **Lack of observed weather data at surface and hub height.** There was a lack of meteorological towers near wind parks, and measured wind speeds at existing towers did not correlate well to observed power generation.

- **Lack of observed power data except at interconnections.** The power generated at each wind park is not always readily available, as the metered value available is the sum of generation feeding into the point of connection to IPC's network. For example, the Mountain Air wind park has six individual parks but only one metered power value, and therefore IPC is unable to correlate power at each geographic location to wind speeds.

- **Terrain.**

  - The existing high resolution of 1.8-km does not accurately model winds of turbine locations on mountainous terrain.

  - High-frequency updates (RUC40) are at 40-km resolution, but wind speeds forecasted for each point available are influenced by terrain that is typically very different from the terrain where the turbines are located.

  - Observed power production and weather forecast patterns in locations like Rockland wind park are not well understood.

  - Because of the proximity to the coast and the resulting limited observation data, forecasts are more than one day out and it is difficult to time weather events.

- **Model timing.** The existence of ramps and drops in power can generally be forecasted, but forecasting the timing of events greater than 24 hours out is more difficult.

- **Data volume and speed.**

  - The WRF-NAM and WRF-GFS forecasts start outputs two to three hours after the forecast execution starts.

  - The use of 1.8-km resolution negates the need for 5.4-km resolution when applied to wind-power forecasting.

- **Contracts.** Power purchase contracts with wind parks were created before the needs of accurate wind-power forecasting were known or considered; therefore, some of the contracts lacked requirements to provide data that would be beneficial to generating more accurate forecasts for the wind parks.

3.4. Timeline & Budget

The baseline timeline for the project was 18 months, and it was completed in 18 months.

The baseline budget for the project was $576,000, and it was completed for approximately $470,000.

4. Future Activities

4.1. Wind Forecast

4.1.1. Incorporating New Forecasting Model Types

IPC is continuously looking for improvements to the current weather model, new weather models, and techniques to improve the wind forecast.

4.1.2. Early Warning System Based on Physical Indicators

IPC plans to detect approaching changes in wind speeds through the use of observations upstream of wind parks or other real-time meteorological gages and create an early warning system based on these observations.

4.1.3. Additional High-Speed Cutout Warnings

IPC plans to develop an algorithm to apply to all the wind parks that would use reasonable high-speed cutout indicators.

4.1.4. Forecast Refinements

The following actions have been identified to refine the forecasts:

- Investigate several other weather parameters to determine correlations to wind power. Some of these correlations are directed at detecting ramps or weather fronts, and others are related to generation accuracy.
- Because a larger dataset is available, recalculate power curves and regression coefficients and possibly divide them on a seasonal basis.
- Discriminate by the time of day or model forecast wind direction.
- Quality control (QC) the model data and discard questionable data.
- Improve the model performance. Research to do so is already being conducted by the UA.

4.1.5. Thunderstorm Detection

IPC has identified that thunderstorms moving through the system cause rapid spikes in system generation; however, exact thunderstorm prediction is difficult. To mitigate this, IPC plans to create a warning system that will let operators know when thunderstorms and resulting generation spikes are possible.

4.1.6. Interactive User Forecast Adjustments

IPC operators may manually adjust the real-time forecast to match the current state of the system and correct errors.

4.1.7. Missed Forecast Analysis

Developing a forecast-analysis log is key to identifying missed forecast events and determining how to create better future forecasts. IPC plans to develop this log.

4.1.8. Real-Time Turbine Availability and Known Maintenance Schedules

IPC plans to better incorporate real-time turbine availability and known maintenance schedules into the wind forecast.

4.1.9. Streamlining the Addition of New Wind Parks

The addition of new parks, although better, is still a tedious process. Because the addition of new parks appears to be diminishing, streamlining this process will be evaluated as needed.

4.2. Short-Term Demand Forecast

The mid- and short-term demand forecasting tool will improve over time as other weather variables are added to the model. The improvements in the neural net equations will also help improve the overall performance of the future load forecasts.

4.3. Reserve Calculations

If a short-term wind forecast method becomes available, the values would be included in regulating margin and reserve calculations, which would provide a more accurate up and down regulation setting from movements in wind generation.

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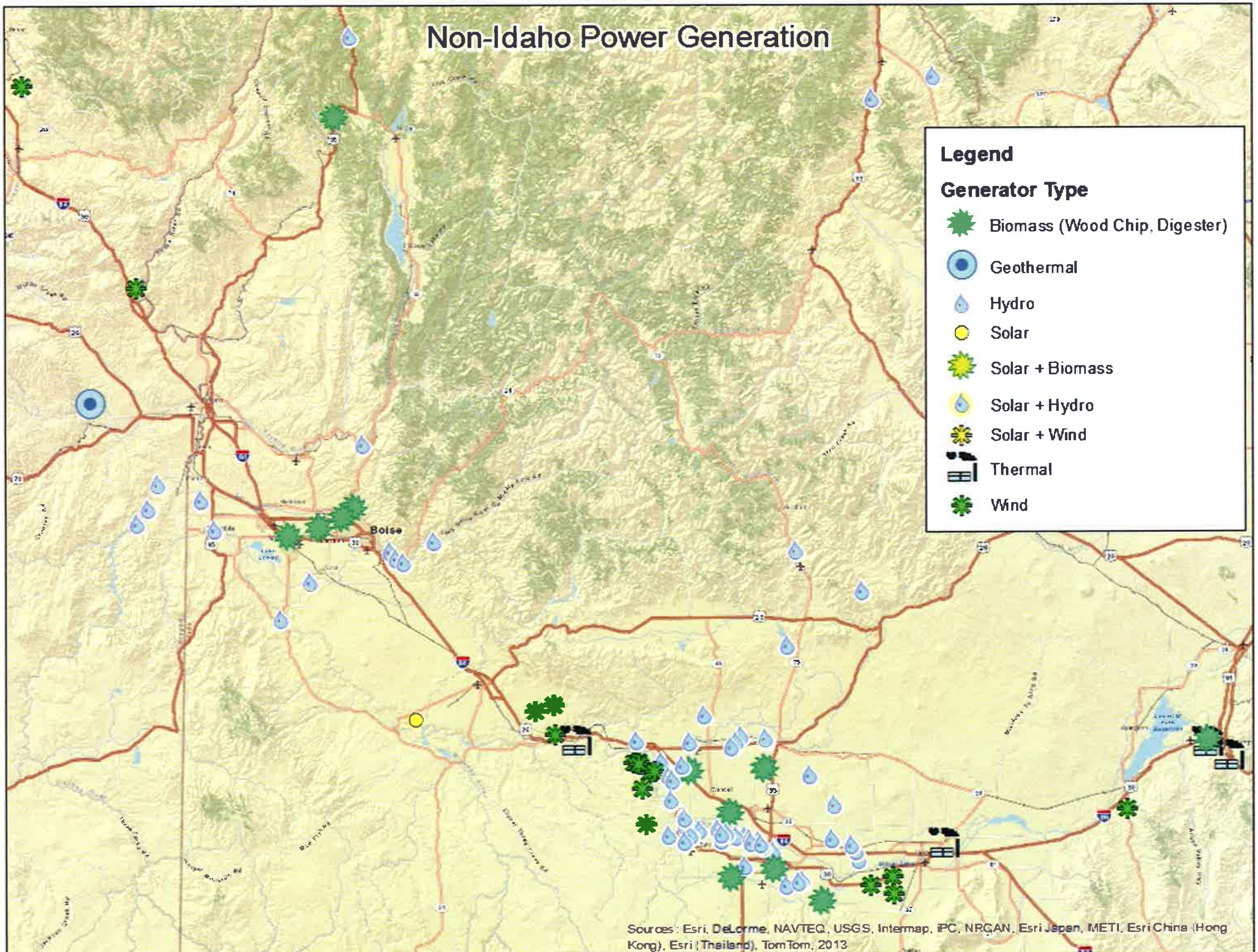
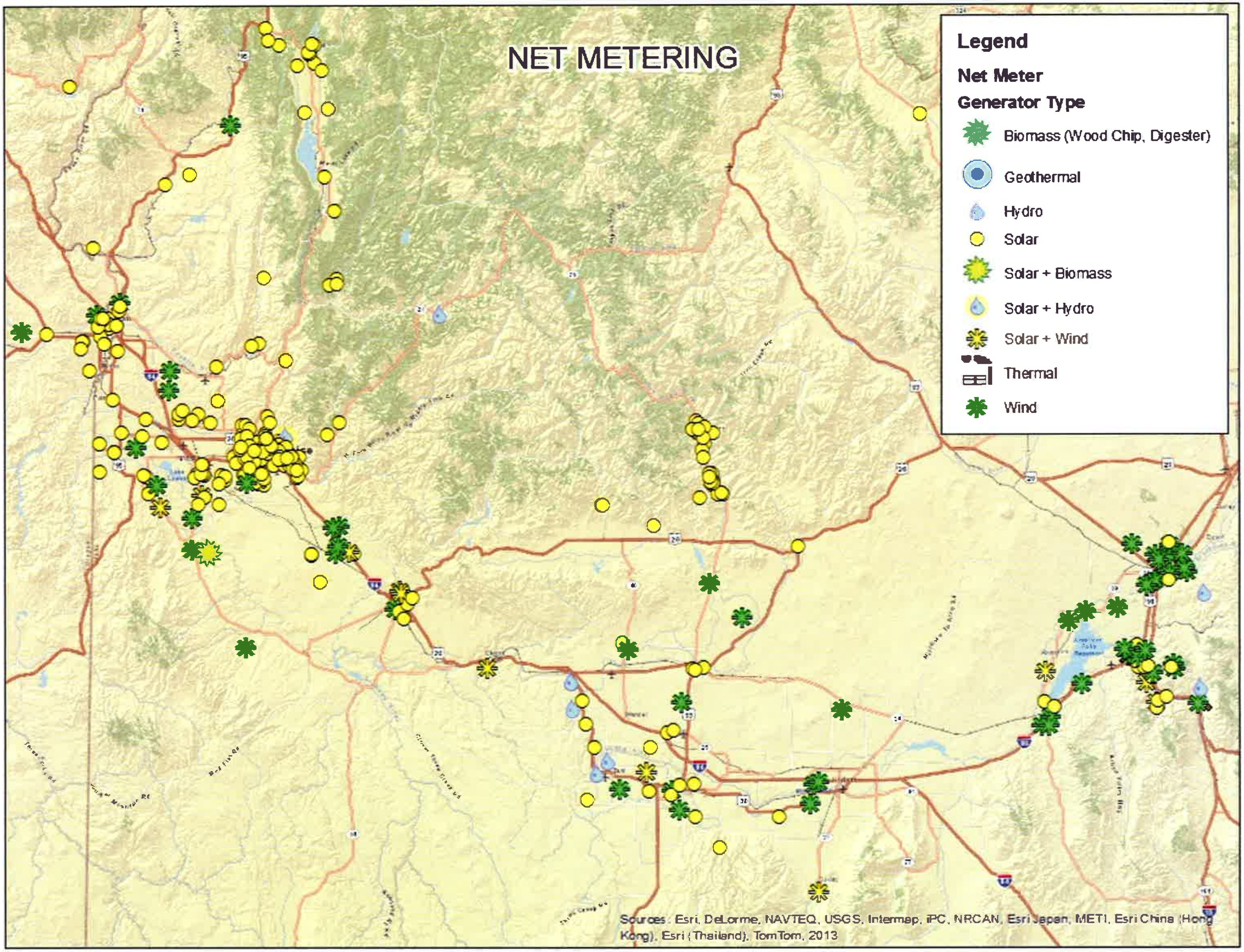
2013 SMART GRID REPORT

Appendix D-11

Maps showing Non-Idaho Generation and Net Metering Projects


Non-Idaho Power Generation
Legend
Generator Type
Biomass (Wood Chip, Digester)
Geothermal
Hydro
Solar
Solar + Biomass
Solar + Hydro
Solar + Wind
Thermal
Wind
Boise
Sources: Esri, DeLorme, NAVTEQ, USGS, Intermap, iPC, NRCAN, Esri Japan, METI, Esri China (Hong Kong), Esri (Thailand), TomTom, 2013


NET METERING
Legend
Net Meter
Generator Type
Biomass (Wood Chip, Digester)
Geothermal
Hydro
Solar
Solar + Biomass
Solar + Hydro
Solar + Wind
Thermal
Wind
Sources: Esri, DeLorme, NAVTEQ, USGS, Intermap, iPC, NRCAN, Esri Japan, METI, Esri China (Hong Kong), Esri (Thailand), TomTom, 2013

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Appendix D-12

Summary of OMS Results
from August 1, 2013 through August 14, 2013

Summary of OMS Results from August 1, 2013 through August 14, 2013

Lily Wu and Mani Venkatasubramanian

Washington State University, Pullman, WA 99164-2752

Email: tianying.wu@email.wsu.edu and mani@eecs.wsu.edu

OMS Parameters:

Window length = 300 seconds

Refresh Rate = 10 seconds

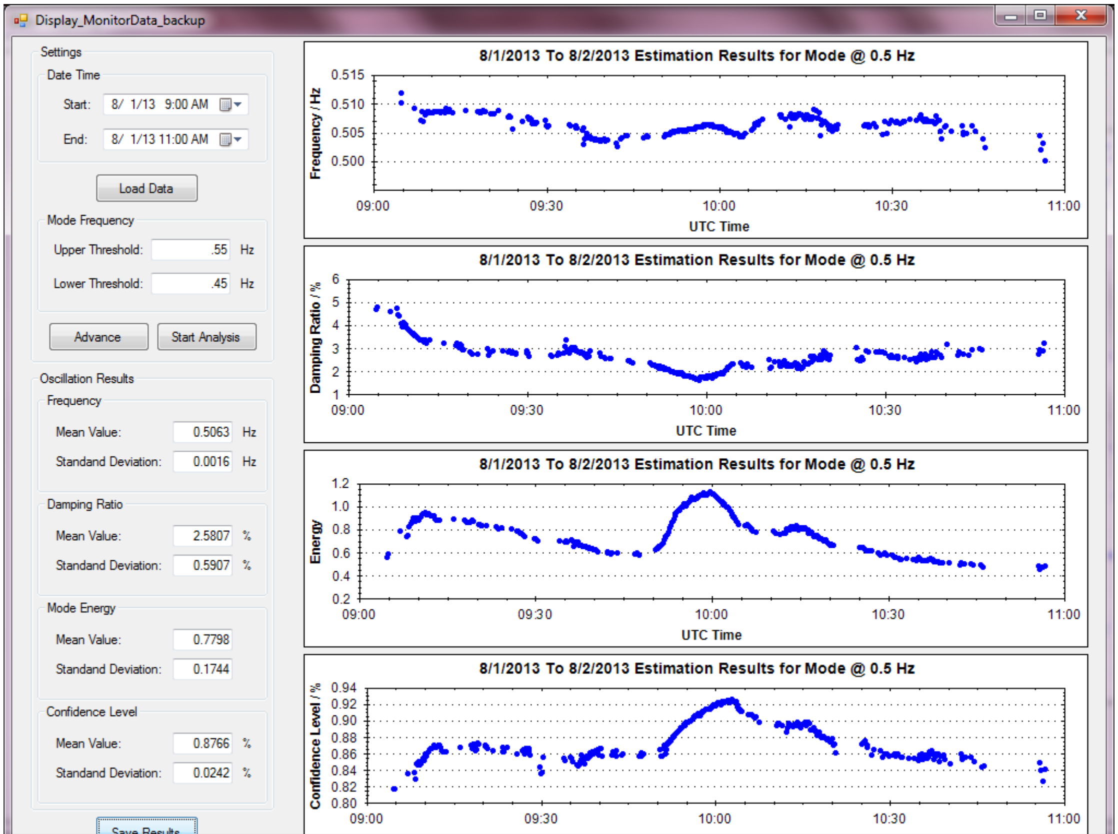
PMUs = 10

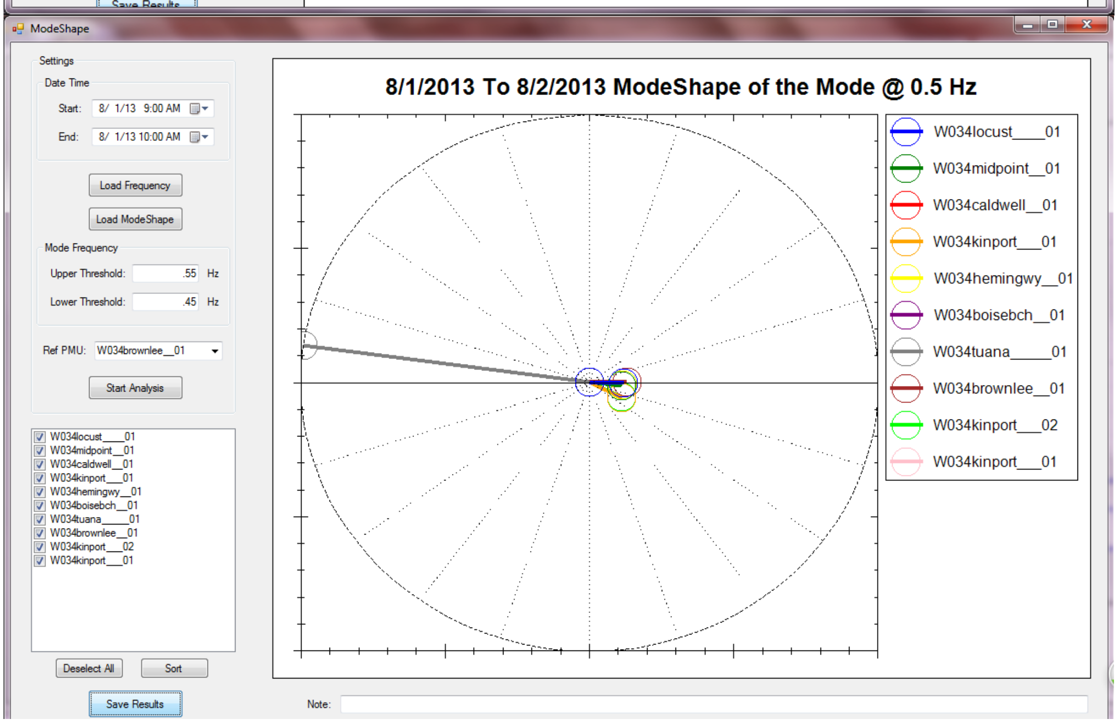
Four modes have been found at around 0.2 Hz, 0.5 Hz, 0.6 Hz and 1.4 Hz. No clear mode found on August 2, August 4 to7 & August 10 to 14.

All the modes were shown occasionally during the testing time. The 0.2 Hz mode was well damped. The 0.5 Hz, 0.6 Hz and 1.4 Hz mode appeared to be poorly damped but their energy and confidence level were low. Recommend to monitor them.

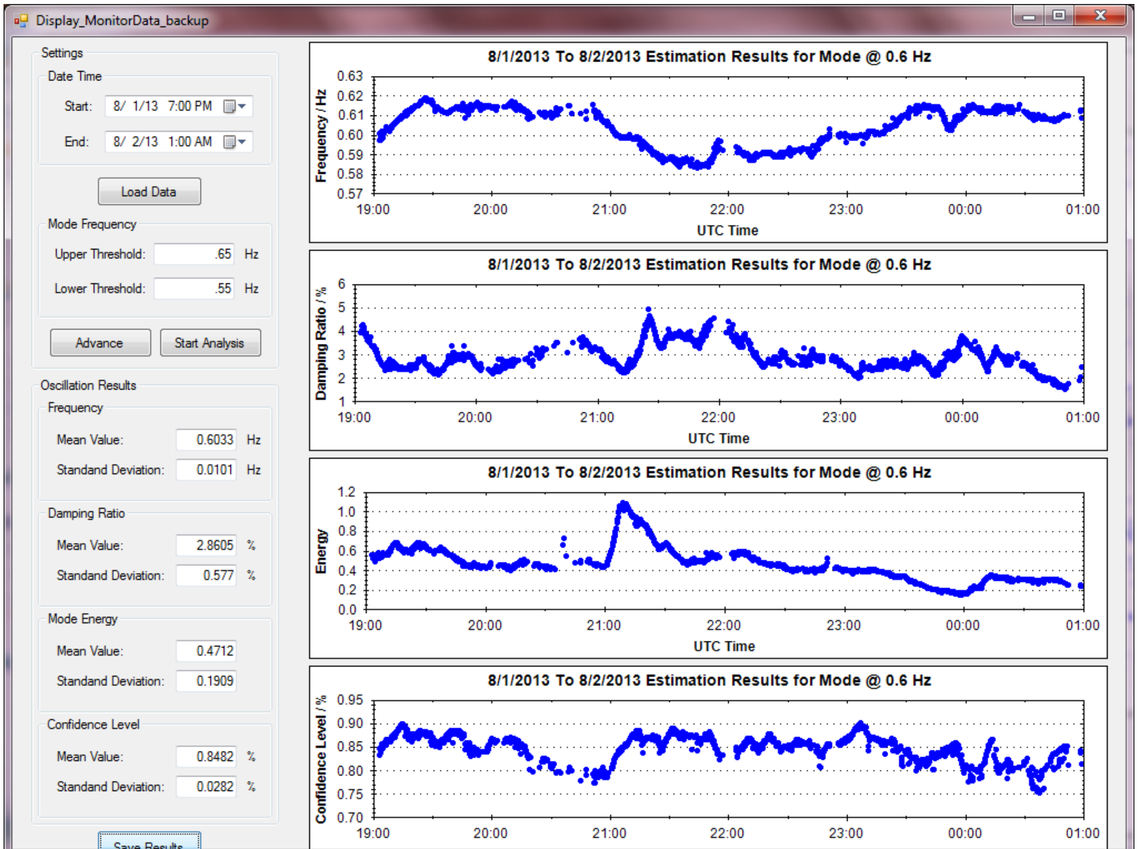
Using UTC time in this report.

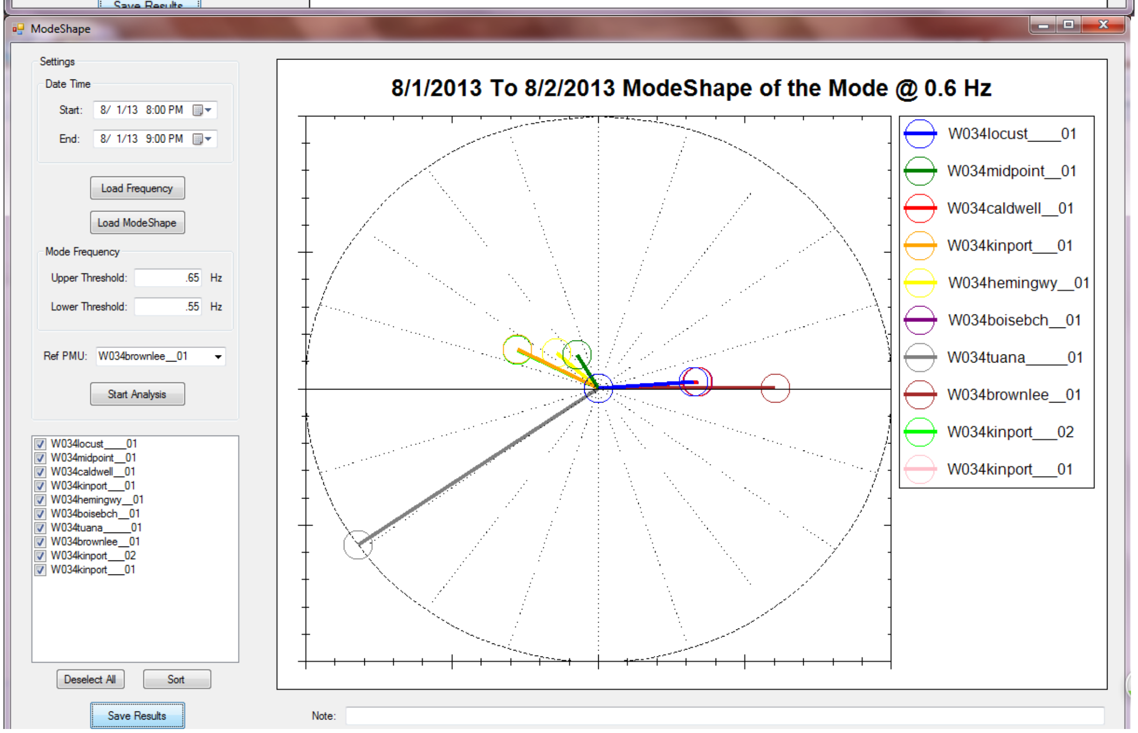
August 1, 2013:





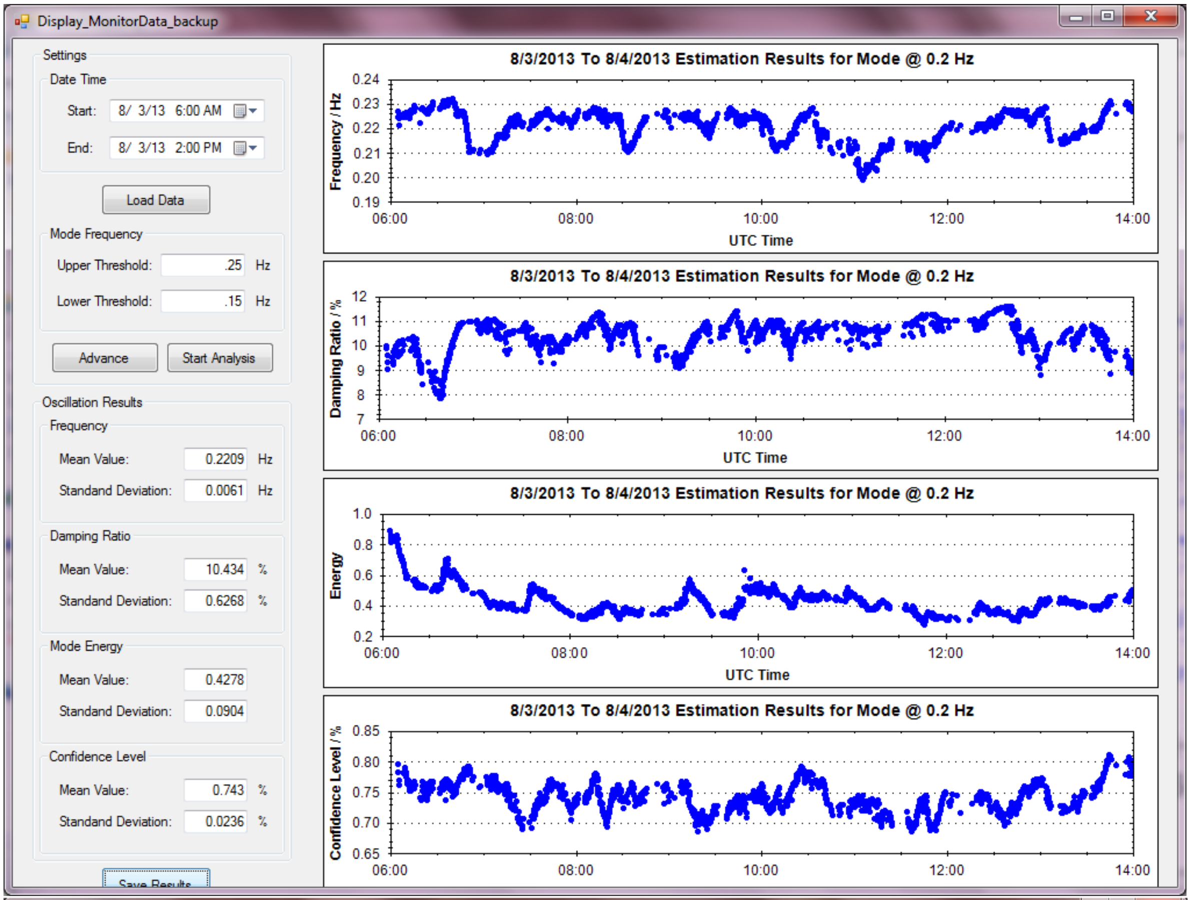
0.5 Hz mode was shown clearly from 9am to 11am, and it appeared to be poorly damped but the confidence level was too low. Recommend to monitor it.

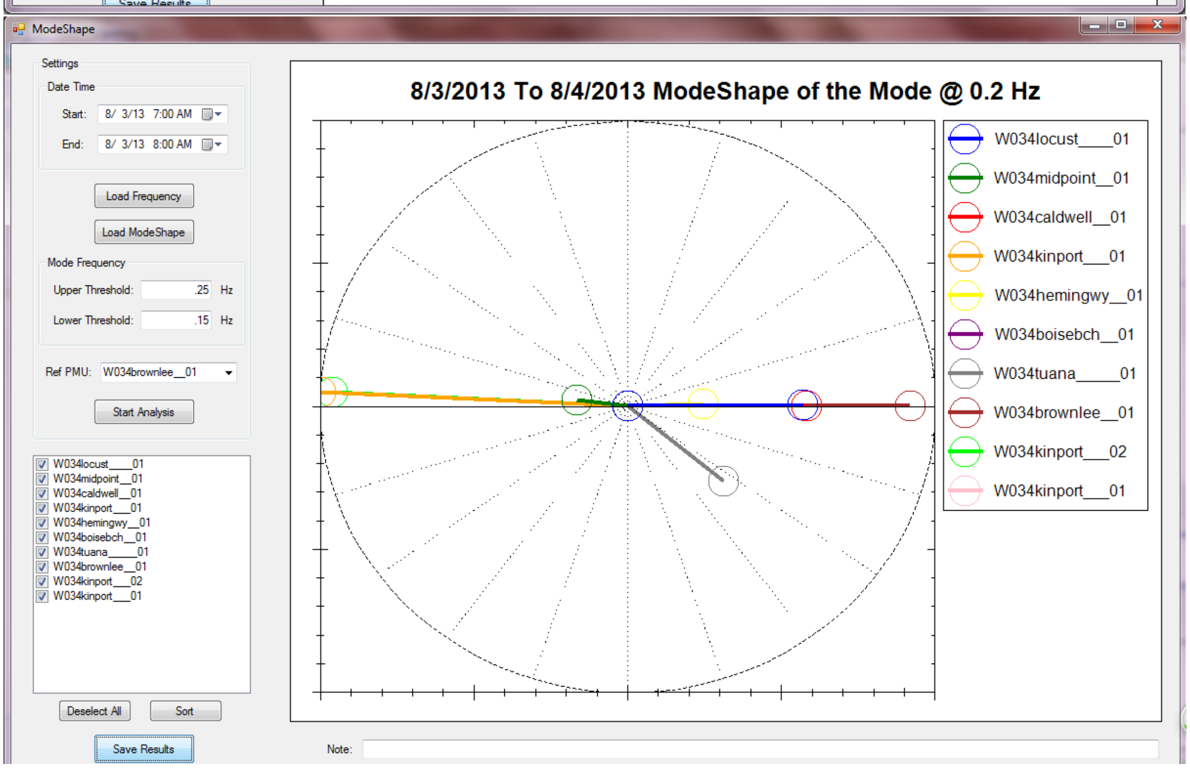


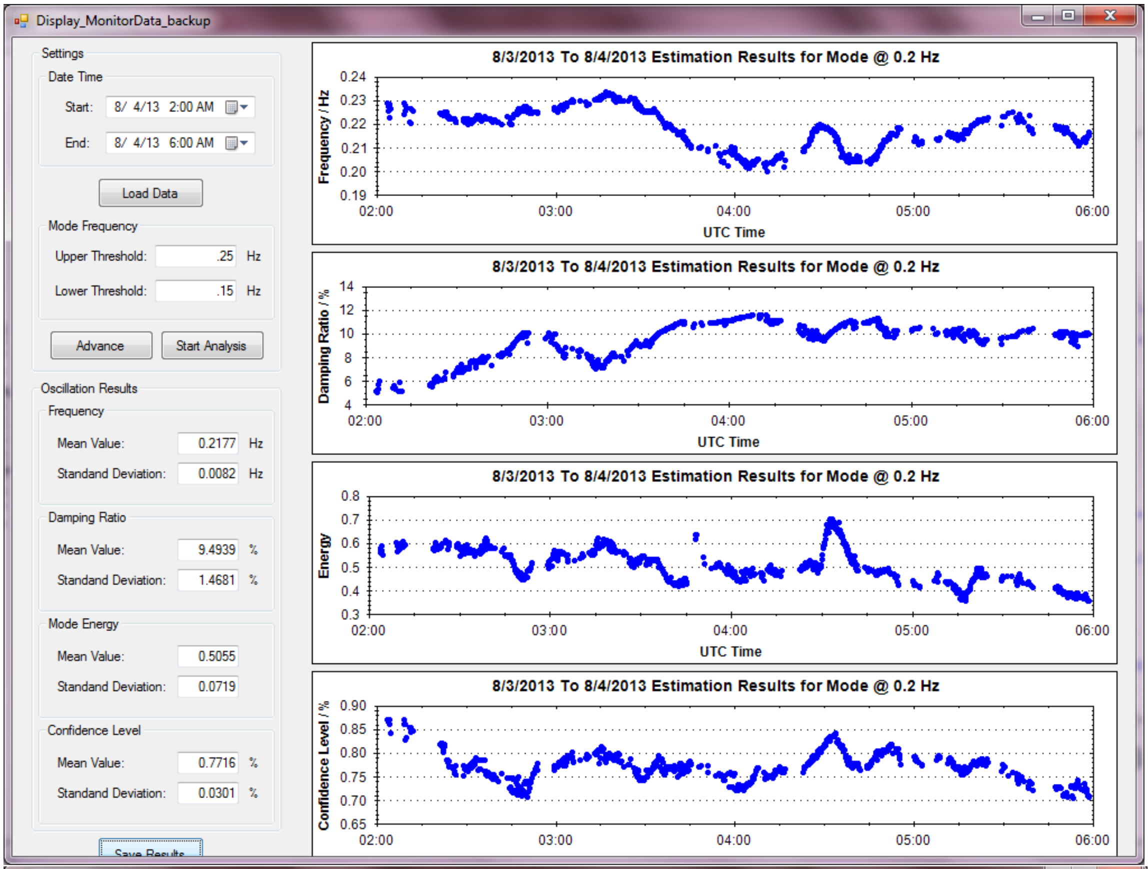


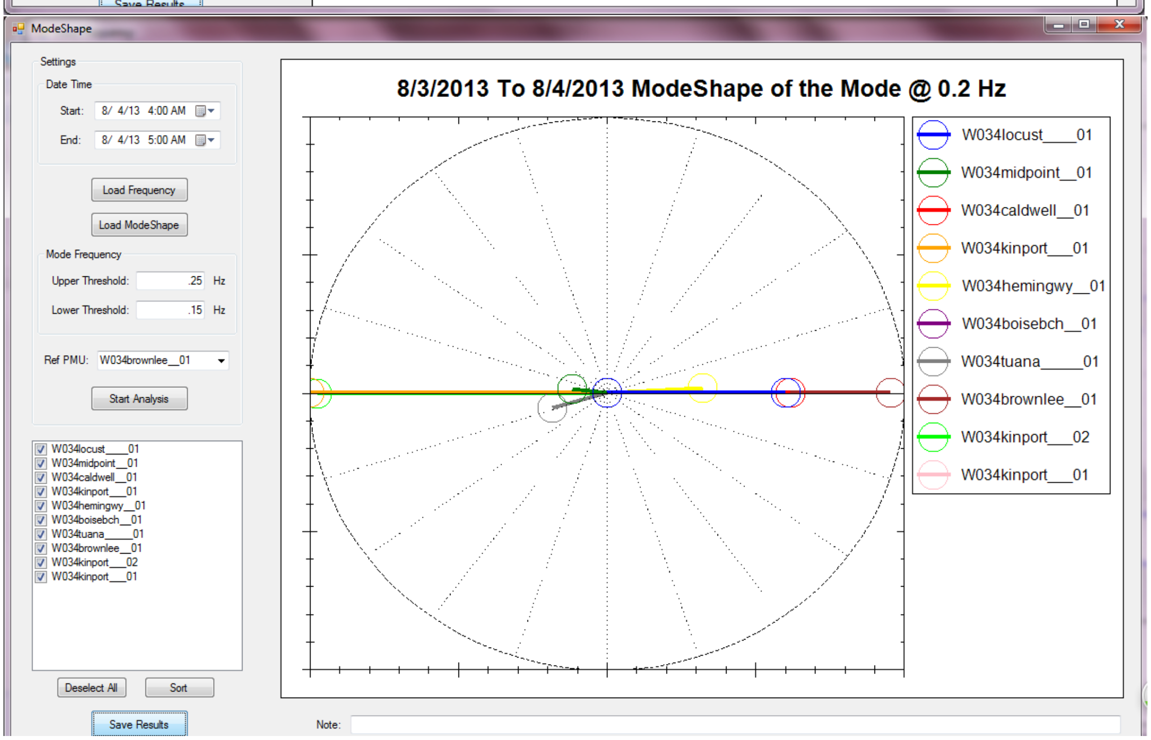
0.6 Hz mode was shown clearly from 7pm to 1am the next day, and it appeared to be poorly damped but the confidence level was too low. The ModeShape kept changing slightly during the testing time. Recommend to monitor it.

August 3, 2013:



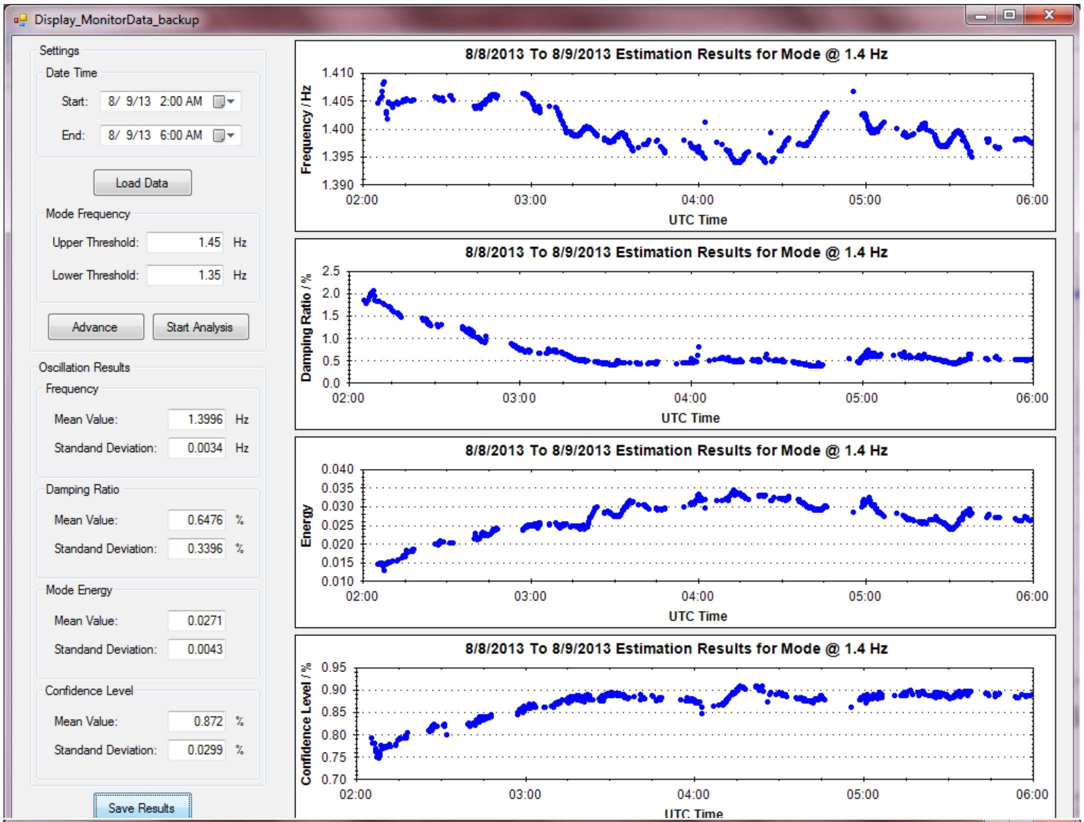


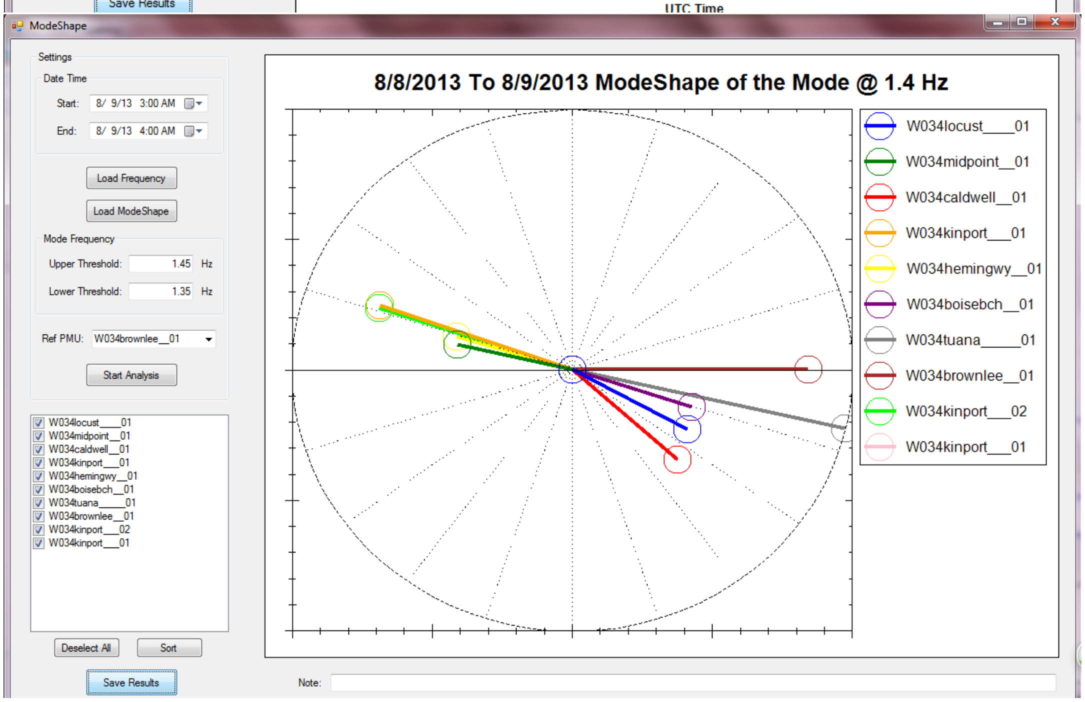




0.2 Hz mode was shown twice, 6am-2pm and 2am-6am the next day, and it was well damped. The magnitude and phase angle of PMU W034tuana_01 were different of the two time period.

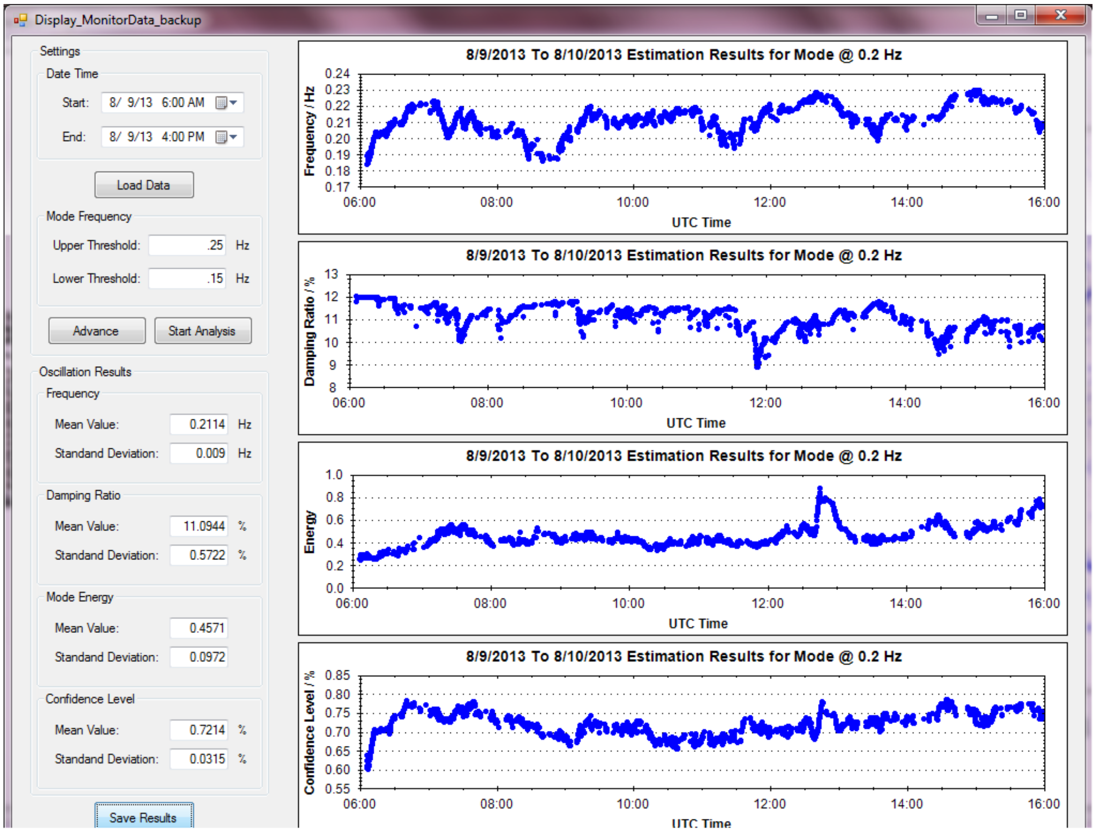
August 8, 2013:

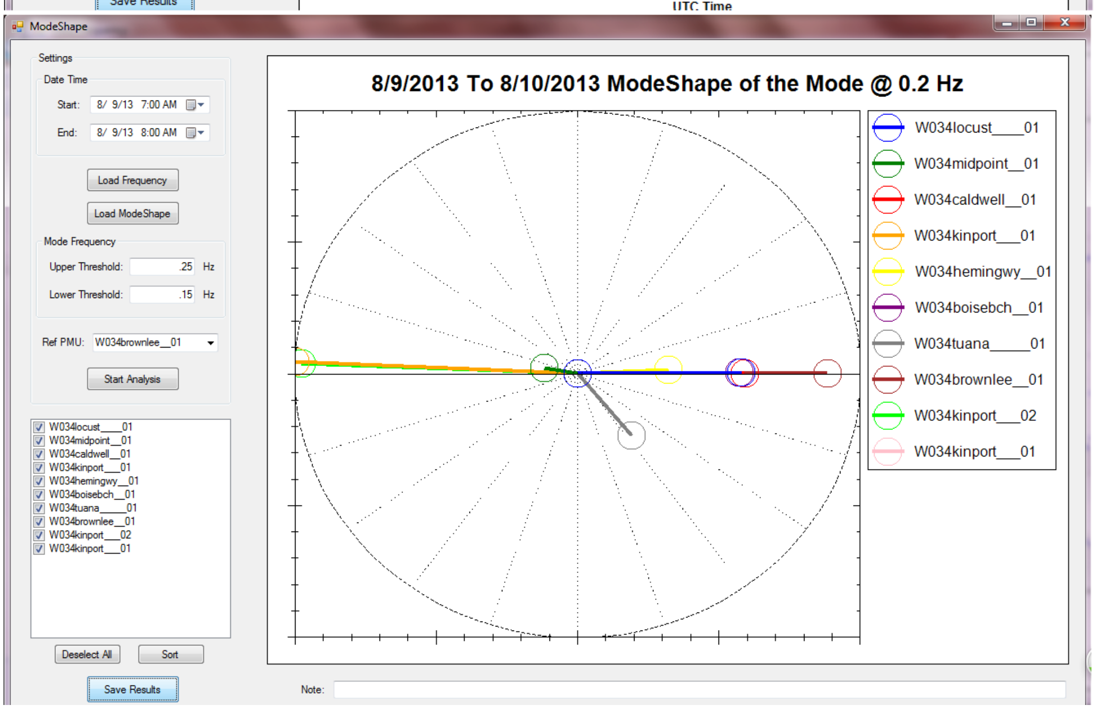




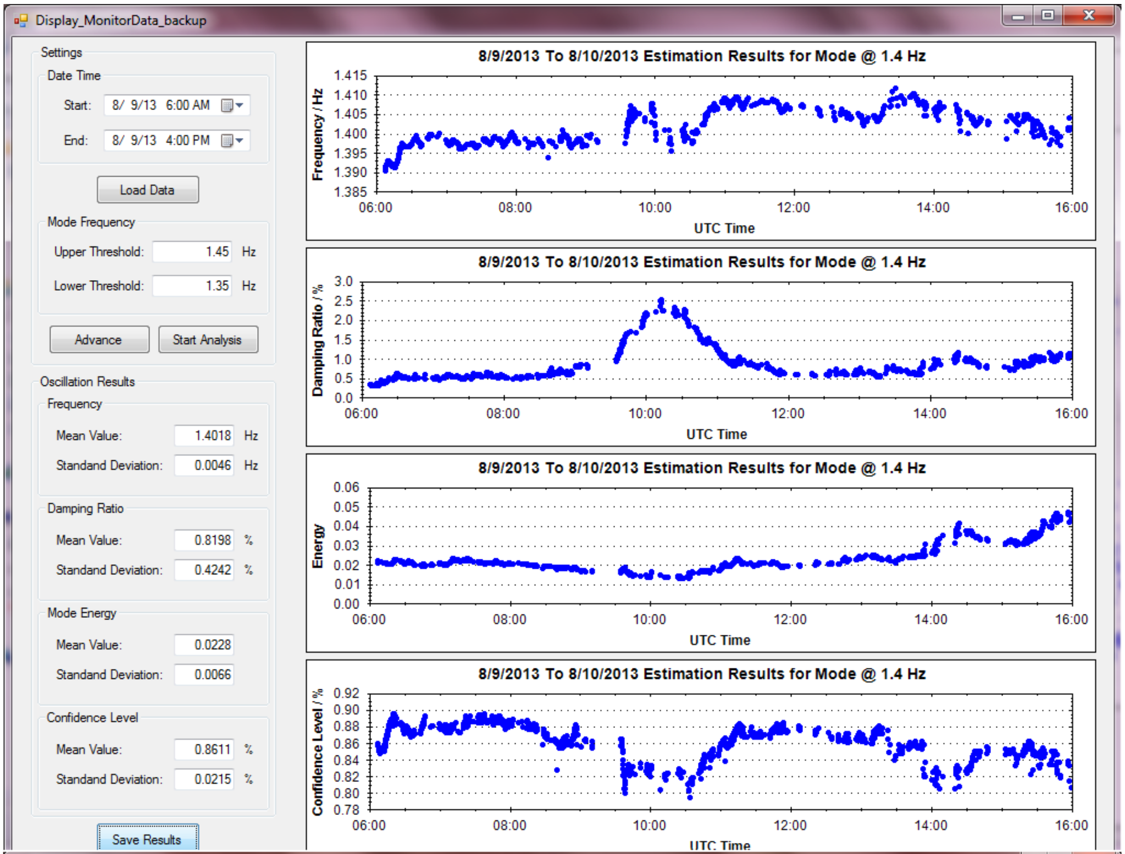
1.4 Hz mode was shown clearly from 2am to 6am the next day, and it appeared to be poorly damped but the energy and confidence level were too low. The ModeShape kept changing slightly during the testing time. Recommend to monitor it.

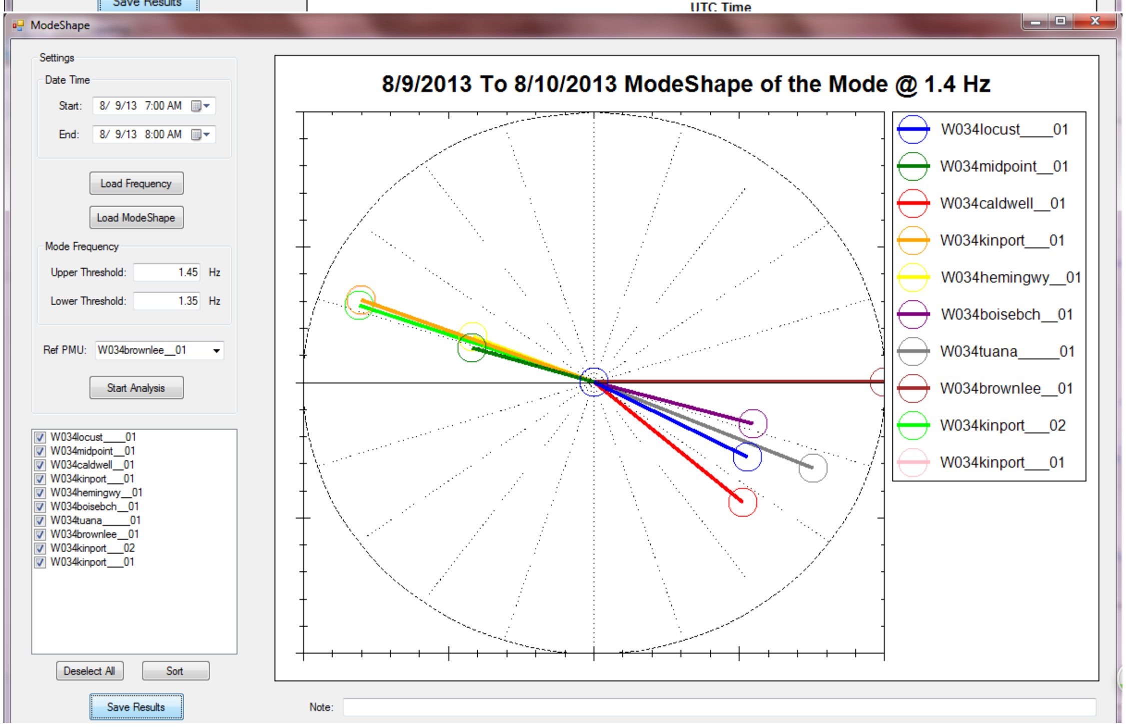
August 9, 2013:





0.2 Hz mode was shown from 6am to 4pm, and it was well damped. The ModeShape kept changing slightly during the testing time. Recommend to monitor it.





1.4 Hz mode was shown from 6am to 4pm, and it appeared to be poorly damped but the energy and confidence level were too low. The ModeShape kept changing slightly during the testing time. Recommend to monitor it.

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2013 SMART GRID REPORT

Appendix D-13

Customer Relationship Management – Lessons Learned

Customer Relationship Management - Lessons Learned

July 2, 2012

Background

Original scope

In August 2009, Idaho Power Company (IPC) filed a Smart Grid Investment Grant (SGIG) Program that included the following project:

> Customer Relationship Management (CRM) Tool: The CRM tool will provide advanced customer intelligence throughout IPC. The CRM tool will advance energy usage reduction and effective energy efficiency programs. From the Enterprise Data Warehouse (EDW) platform, the CRM tool will leverage customer meter, vendor, and billing data. The data will be analyzed and used to provide customers with desired energy efficiency information, and to increase participation rates among energy efficiency programs.
>
> During the first phase of the project, IPC will establish the hardware and software environment, including servers, storage, network, and project facilities, and implement the base EDW and CRM applications into development and test environments, with a production environment established as load capacity is confirmed. The remainder of the project will include the CRM configuration, integration design, and development between data sources, and the EDW. Final phases will include testing of all end-to-end processes, ensuring data integrity and, finally, implementation.

Revised scope

The IPC Project Execution Plan was updated in August 2011 and the new CRM project reads as follows:

> CRM: The CRM application will be acquired as part of the SAP Customer Relationship & Billing (CR&B) software package but will not be fully configured and implemented at this time. At a future point in time, once implemented, the advanced CRM functionality will provide two major business benefits to Idaho Power. First, the application will provide advanced customer intelligence throughout IPC. IPC will begin the process of collecting customer attributes, consolidating IPC and customer interactions, and in the longer term, allow IPC to interact with our customers in the manner they prefer about the topics they are interested in. Additionally, the application will advance energy usage reduction and effective energy efficiency programs. Integrating customer data from across multiple data sources, the consolidated information will be analyzed and used to provide customers with desired energy efficiency information targeting increased participation rates among energy efficiency programs.

Project Activities

Planning and requirements

In accordance with IPC standard project methodology, the project team completed formal planning and requirements processes.

Project Planning

This primarily includes the development of detailed scope statements, project specific deliverables, stakeholder analysis, requirements definition, RFP process execution, and a preliminary assessment of the organizational change activities required to successfully complete the CRM implementation.

Requirements Definition

There are multiple specific deliverables from the requirements definition activities. These include:

- CRM functional requirements – these requirements outline what functionality the system must provide for the system users.
- CRM non-functional requirements – describe the quality characteristics of the system. Examples would include performance, availability, security, and reliability.
- Use case development – use cases define the interactions between the system user and the system itself to perform a given business function.
- Reporting requirements – a high level identification and description of the reports the system would need to produce.
- As-is process documentation – a high level flow of current business processes to be used in mapping to the future state processes.
- Integration requirements – a preliminary identification and mapping of other IT systems within the IPC application portfolio that CRM would need to interface with.

RFI/RFP Process

Upon completion of the requirements definition, the project team executed the RFP processes. Due to the integrated nature of the CRM functions and the Customer Information System functions, the two project teams conducted a consolidated RFP to evaluate potential solutions and a second RFP to evaluate 3rd party integrators to assist with implementation. Idaho Power contracted with Micon Consulting to assist with the RFP processes starting with the identification of potential solutions and ending with executed software and integrator contracts.

Evaluated Solutions

The complexity and breadth of the combined Customer Information System and the CRM requirements quickly narrowed the potential suppliers. The evaluation process included the following activities:

- Evaluation of the supplier response to our RFP questions by business requirement category
- Supplier evaluation of work day estimates, pricing quotes
- IPC strategic assessment
    - Enterprise architecture assessment
    - Disaster recovery options
    - Integrations with other IPC IT projects
    - Evaluation of the long term supplier vision / roadmap
    - Information security assessment
- Completion of a one week functionality demonstration by each supplier

Based on the overall evaluation and the company's long-term strategic vision, IPC selected SAP as their go-forward software solution and platform.

Evaluated 3rd Party Integrators

Once SAP had been selected, IPC performed an RFP process to select a 3rd party integrator to assist with the SAP implementation. The selection of a 3rd party integrator was expanded to include the Enterprise Data Warehouse (EDW) project requirements. IPC's objective was to maximize the synergy and reduce the management overhead associated with the implementation of two large, complex, and highly integrated applications.

Three participants were included in the RFP process.

The evaluation criteria included:

- Vendor qualifications
- Project methodology
- An initial review and assessment of their Professional Services Agreement
- Pricing
- Oral presentations
- On-site interviews
- Site visits and telephone surveys with their existing customers.

Based on the overall evaluation, IPC selected HCL Axon as their combined Integrator for the SAP and EDW implementation.

Lessons Learned

- SAP provided three clear differentiators. First, the integration between the Customer Relationship and Billing (CR&B) functionality and the CRM functionality was seamless. In fact, the CRM tool suite provides the Graphical User Interface (GUI) to the CR&B application. Second, SAP provided a consistent technology stack and user interface. And lastly, SAP demonstrated a stronger long term vision and roadmap for their application design and development relational to CRM functionality.
- The CRM space is extraordinarily broad, requiring IPC to clearly define a very focused project scope.
- CRM's need for diverse and complex datasets (over 40 where identified) requires significant focus on information architecture.
- There is significant value as well as challenges in aligning CRM business process and needs with those of the customer service center.

Final decision to defer the project

The difficult decision to defer the more advanced CRM functionality supported a recognized need to reduce both implementation time and costs based on the three year requirement to complete all SGIG projects. The licensing, test and production environments, and base configuration will be implemented as part of the CR&B implementation.

Future of the projects at Idaho Power Company

Although the CRM project was deferred at the time of the overall SGIG implementation, the CRM advanced functionality has been scoped as a standalone effort and submitted as part of the 2014 budget.

Budgets and Expenditures

Original Budget

The original budget in the SGIG PEP was $1,163,137.

Money Spent

$180,296.77

Revised Budgets with Explanations

The budget in the revised SGIG PEP was $180,297.

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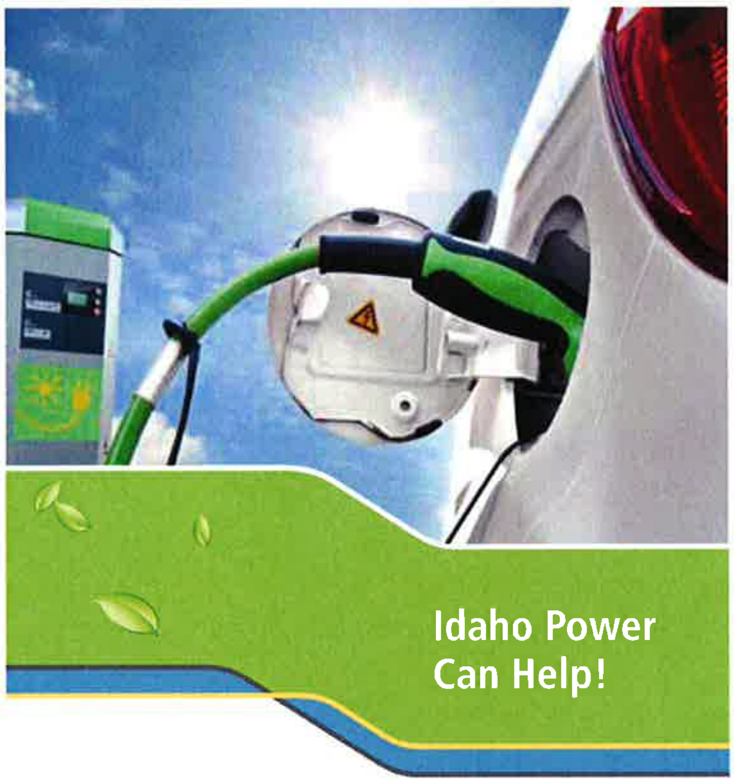
2013 SMART GRID REPORT

Appendix D-14

Informational Brochure to Current Electric Vehicle Owners

Thinking About an Electric Vehicle?



IDAHO POWER
An IDACORP Company

I'm Interested – How Do I Charge It?

There are three basic types of charging methods, listed below. The time it takes to fully recharge depends on the type of vehicle, temperature, driving habits and the type of charging station, among other factors.

Level 1 – 120V: This is the standard outlet you have in your home. Using this method, your vehicle will slowly recharge. It's recommended that this be a dedicated outlet with nothing else plugged into it.

Level 2 – 240V: Typically found at businesses or public sites, these charging stations also are available for home use. See next panel for information on home installation. This type of unit will recharge your vehicle much faster.

Fast Charging – These units typically are in place at public facilities. Note that not all EVs are equipped for 480V fast charging.