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REPORT NAME: 2014 Smart Grid Report

COMPANY NAME: Idaho Power Company

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If known, please select designation: ☒RE (Electric) ☐RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☐OAR
☐Statute
☒Order 12-158
☐Other

Is this report associated with a specific docket/case? ☐No ☒Yes

If yes, enter docket number: UM 1675

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Lisa D. Nordstrom
Lead Counsel
lnordstrom@idahopower.com

October 1, 2014

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

RE: UM 1675 - Idaho Power Company's 2014 Smart Grid Report

Dear Sir or Madam:

Idaho Power Company herewith submits for filing its 2014 Smart Grid Report in compliance with Order No. 12-158 in Docket No. UM 1460 and Order No. 13-481 in UM 1675. In addition to the Smart Grid Report, the Company has included the following documents:

Appendix A – Status of Smart Grid Initiatives – 2013 and 2014
Appendix B – Newspaper ad and email solicitation
Appendix C – "Dynamic Line Rating: Concept, Case Study, and Regulatory Review" by INL
Appendix D – Time of Day Final Study Report
Appendix E – Transmission Situational Awareness Oscillation Monitoring Presentation
Appendix F – Peak Reliability Press Release
Appendix G – Conservation Voltage Reduction Enhancements Project Plan
Appendix H – ENGO Static VAR Device Pilot Project Plan
Appendix I – Demand Response as Operating Reserves Feasibility Report

Please address all data requests and other communication to:

Electronic: dockets@idahopower.com
Regular Mail: Lisa Nordstrom
Idaho Power Company
1221 W. Idaho Street
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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

LDN:kkt
Enclosures
cc: Service List – UM 1675
Service List – UM 1460
Service List – LC 58
Service List – UE 233
RA Files
Legal Files

CERTIFICATE OF SERVICE

UM 1675

I hereby certify that on October 1, 2014, I served a true and correct copy of Idaho Power Company's 2014 Smart Grid Report on the parties in Dockets UM 1460, LC 58, UE 233, and UM 1675 by e-mail to said person(s) as indicated below.

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Smart Grid Report

October 1, 2014

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ACRONYM LIST

A/C	Air Conditioning
ACC	Automated Capacitor Control
ANSI	National Service Voltage Standard
AMI	Advanced Metering Infrastructure
ARRA	American Reinvestment and Recovery Act
ATC	Available Transfer Capability
CGI	CGI Group Incorporated
CIS	Customer Information System
CHIP	Charging Impacts Project
CR&B	Customer Relationship and Billing
CRM	Customer Relationship Management
CSPP	Cogeneration and Small Power Producers
CSR	Customer Service Representative
CVR	Conservation Voltage Reduction
DMS	Distribution Management System
DOE	Department of Energy
dQ/dV	Delta-Q/Delta-V
DR	Demand Response
DSM	Demand-Side Management
EDW	Enterprise Data Warehouse
ENGO	Edge of Network Grid Optimization
ETC	Expected Transmission Commitment
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GIC	Geomagnetic Induced Currents
GMD	Geomagnetic Disturbance
HAN	Home Area Network
IEE	Itron Enterprise Edition
ILC	Irrigation Load Control
INL	Idaho National Lab
IPC	Idaho Power Company
IRP	Integrated Resource Plan
IT	Information Technology
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LLC	Limited Liability Company
LSE	Linear State Estimator
LTC	Load Tap Changer

MDMS	Meter Data Management System
MVAr	Megavolt-ampere-reactive
MW	Megawatt
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electricity Reliability Commission
OMS	Outage Management System
OPUC	Public Utility Company of Oregon
OSI/PI	OSIsoft, LLC/PI enterprise infrastructure management software platform
PLC	Power Line Carrier
PMU	Phasor Measurement Unit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RC	Reliability Coordinator
RD&D	Research, Development and Deployment
RIT	Renewable Integration Tool
SE	State Estimator
SGIG	Smart Grid Investment Grant
SGM	Smart Grid Monitoring
TOD	Time Of Day
TVP	Time Variant Pricing
VAr	Volt Ampere Reactive
VSMS	Voltage Stability Monitoring System
VVMS	Volt/VAr Management System
WECC	Western Electricity Coordinating Council
WSU	Washington State University
YE	Year-End

EXECUTIVE SUMMARY

Idaho Power Company (Idaho Power or company) is pleased to present its 2014 Smart Grid Report in compliance with Order No. 12-158 issued by the Public Utility Commission of Oregon (Commission or OPUC) in Docket UM 1460. The Commission's smart grid goal and objectives as set forth 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 second annual *Smart Grid Report* and addresses the company's efforts toward accomplishing the Commission'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.

Idaho Power evaluates new smart grid technologies and opportunities 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.

In addition to fulfilling or meeting Commission reporting requirements, this document serves as a high level strategic document for Idaho Power to plan and track its smart grid projects. It acts as a company-wide repository of all smart grid projects, reports, and studies underway or planned in the near-term future.

The Commission's specific recommendations for this report included in Order No. 13-481, Docket UM 1675, are reviewed in Section V, Targeted Evaluations.

Also included as Appendix A is Idaho Power's Status of Smart Grid Initiatives – 2013 and 2014.

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. Idaho Power enhanced the stakeholder input process this year in an effort to get more meaningful public input and to respond to OPUC Staff's recommendation as included in page 2 of Appendix A, Order No. 13-481, UM 1675. Staff recommended that "in the future, it may be beneficial for the Company to circulate a draft version of the report at the same time they solicit comments." Idaho Power compiled a draft report which was available for review by the public and other stakeholders during the review period.

To solicit input from the general public, Idaho Power placed an advertisement—Share Your Ideas About Smart Grid—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 1 and 10, 2014, and in the *Hells Canyon Journal* (Halfway) on August 6 and 13, 2014. On August 1, 2014, Idaho Power sent an email soliciting comments to all parties on the service lists for the Smart Grid docket, UM 1460; Idaho Power's last general rate case docket, UE 233; Idaho Power's last integrated resource planning docket, LC 58; and Idaho Power's 2013 Smart Grid Report docket, UM 1675. Idaho Power requested comments be submitted by August 31, giving parties 31 days to provide responses. Idaho Power included a web link in the newspaper ads that accessed a copy of the draft Smart Grid Report and attached a draft Smart Grid Report to the email solicitation. Idaho Power did not receive any comments or suggestions as a result of the newspaper advertisement or email solicitation. Copies of the newspaper advertisement and email solicitation are provided in Appendix B.

I. Smart Grid Goals, Objectives, Strategy, and Process

The smart grid is a concept whereby utilities deploy new technologies to reduce costs and improve the operation of the electrical power system. As an industry, utilities have been doing this for years; it is not new. What is new is the speed in which new technologies are becoming available and the abundance of data now available through smart meters and monitoring devices.

This document represents a vision of what Idaho Power's future may look like in the near to mid-term and presents various projects and programs that Idaho Power is undertaking or may undertake to prepare for that future. Some of the projects are already underway while others are for future implementation. The Smart Grid Report is a vision paper supported with concrete studies and analysis created by a working group of Idaho Power senior managers and senior staff. The vision represented herein is forward looking and as such, may be adjusted in some areas as the years progress.

A. Goals and Objectives

The Smart Grid is Customer Centered

The smart grid concept provides customers easier access to their energy use information and empowers them to act on that information. It provides real-time signals to customers and in general, serves them in a manner that allows them to be more involved and proactive in managing their energy use. Idaho Power believes that the customer will expect utilities to provide a different experience than the traditional paradigm of service provided today. One driver of this paradigm change is motivated by the increasing use of technology in our everyday lives. Idaho Power believes customers will and do expect a different experience than what has been traditionally provided. Customers will seek an experience that includes information that enables them to make choices in their energy use.

The Smart Grid is Data Rich

The smart grid is a data rich environment with embedded sensing devices located throughout the electric system that allows for automation of protection and control while providing the information needed to more efficiently operate the system. It provides two-way flows of information between devices and between Idaho Power and its customers. It gives the utility the ability to more efficiently integrate distributed resources. It provides resiliency in utility response to storm or event driven outages, speeding up restoration efforts.

Edge of Network

The smart grid is moving to the edge of the network – an area where utilities have traditionally not gone. This edge goes all the way down to the secondary side of the service transformer and even into the homes and businesses served by Idaho Power. The ability to control power quality down to the customer level enables the system to become more efficient and responsive to customer needs while maintaining customer privacy.

The smart grid represents an opportunity to enhance the value customers receive from the electric system. Idaho Power is committed to helping customers realize this value through good planning and making wise investments, considering both costs and benefits associated with any smart grid project. Idaho Power must accomplish what is required to realize this vision while maintaining the safety and reliability expected of it by both customers and employees. By optimizing and modernizing the power system, Idaho Power can enhance customer service, improve power reliability, promote energy efficiency, and more efficiently integrate renewable resources.

At Idaho Power, the smart grid vision consists of seven major characteristics:

1. Enhance customer participation and satisfaction
2. Accommodate generation/energy 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

B. Strategy

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

Operations

Idaho Power will make considerable investments in the coming years in real-time sensing, diagnostic, communications, and control equipment to increase the efficiency and reliability of the system and make the system more resilient. Simultaneous with these investments, Idaho Power must mold together planning activities, field work, and operations. Actions will be taken to integrate new operations tools into existing tools that are familiar to system operators.

Determining a strategy for communicating with the many devices to be installed on the electrical system is critical to the smart grid's long term success. While Idaho Power has operated a number of different communication systems for many years, many of the systems are becoming outdated or have reached capacity. A distribution system communications strategy must provide speed, bandwidth, and high security while minimizing costs.

Some specific operational projects that will be undertaken and are described more fully in this report are:

- Replace the Outage Management System (OMS)
- Refine the renewable energy (wind) integration tool
- Install a transmission line situational awareness tool
- Pilot a substation fiber-based protection and control pilot
- Enhance the existing Conservation Voltage Reduction (CVR) program
- Replace the Automated Capacitor Control (ACC) system
- Develop a distribution communications strategy

Customer Systems

Idaho Power believes that its customers' expectations are changing and they want more information about their energy use. In order to provide customers easier access to information about their energy use and enable them to take actions based on that information, many background activities must take place.

Some specific customer systems projects that will be undertaken and are described more fully in this report are:

- Refine the Enterprise Data Warehouse (EDW)
- Develop a Customer Relationship Management (CRM) system

Advanced Metering Infrastructure (AMI)

With most Idaho Power meters now having AMI capabilities, Idaho Power seeks to more fully utilize the tremendous amount of information received to improve service offered to its customers. These meters also possess additional functionality that needs to be investigated.

Some specific projects that will be undertaken and are described more fully in this report are:

- Implement automated connect/disconnect through the AMI system
- Upgrade station communications
- Upgrade the Meter Data Management System (MDMS)
- Upgrade Irrigation Load Control (ILC)
- Investigate the ability of AMI to control line devices

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.

C. Process

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 1.

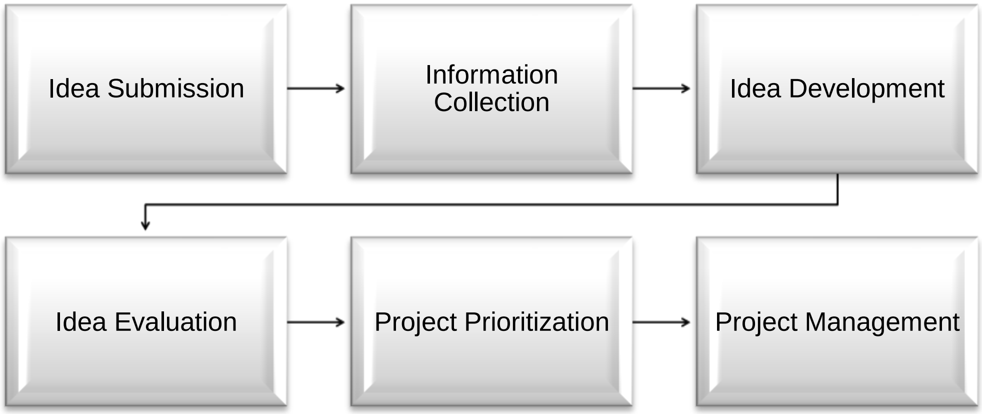

Figure 1. Idea Processing

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 deployable pilot projects 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.

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

Several pilot projects are underway to expand the Transmission Situational Awareness Project described in the 2013 Smart Grid Report. These projects are described in more detail in the Future Smart Grid Investments section. More specifically, the projects are:

- Transmission Situational Awareness Oscillation Monitoring Pilot
- Transmission Situational Awareness Voltage Stability Monitoring Pilot
- Transmission Situational Awareness Grid Operator's Monitoring & Control Assistant

Transmission Situational Awareness Peak Reliability (RC) Hosted Advanced Application

The western system RC, now titled Peak Reliability, maintains a Western Electricity Coordinating Council (WECC)-wide State Estimator (SE) data model for real-time transmission system contingency analysis so its operators can perform their primary function of maintaining system-wide reliability. "Contingency" refers to changes in the modeled system due to non-normal events such as a line or generator outage.

Maintaining a WECC-wide SE data model has proven very difficult for operators and planners due to system complexity and differences in the models used by the various utilities in the WECC. Peak Reliability developed a slate of advanced applications to maintain the system estimator. These advanced applications provide users with an assessment of the current state of the transmission system including:

- Voltage magnitude and angle at all modeled buses
- Megawatt (MW) and megavolt-ampere-reactive (MVAr) flow on all lines and transformers
- MW and MVAr flow on loads and generating units
- Transformer load tap changer (LTC) tap position
- Phase shifter tap position
- Identification of pre- and post-contingency facility rating, System Operating Limit, and Interconnection Reliability Operating Limit exceedances
- Identification of network islands
- Identification of potential post-contingency cascading outages
- Identification of potential post-contingency islanding conditions

The advanced application tools used by Peak Reliability consist of:

- Real-Time Network Analysis tools:
  - State Estimator
  - Real-Time Contingency Analysis
- Network Study Applications
  - Power Flow
  - Study Contingency Analysis
- Fast Network Analysis

Several years ago Idaho Power proposed that it be given the ability to remotely use an instance of the Peak Reliability advanced applications for real-time contingency analysis by installing a system for remote access and retrieval of the SE solution. By September 2014, it is expected that the hardware and applications for remote support will be installed at Idaho Power. Additionally, seven other utilities in the WECC are now using the advanced applications tool with a number of other utilities expected to join in 2015. Other utilities currently using the hosted advanced applications tool are Avista, Northwestern Energy, Grant County Public Utility District (PUD), Chelan County PUD, Douglas County PUD, Tucson Electric Power, and Seattle City Light.

Available Transfer Capability (ATC) Calculation Tool

As described in the 2013 Smart Grid Report, Idaho Power, in collaboration with Pacific Northwest National Lab, developed a probabilistic-based method and tool flexible enough to allow Idaho Power to determine the ATC for any existing and future transmission 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 system utilization.

The initial ATC tool has been developed and evaluated by Idaho Power. The calculations and methods have been verified; however, the software does not have sufficient flexibility to model future system changes. Idaho Power has contracted with North Carolina State University to develop a graphical user interface to adjust the program inputs to expand the applicability of the tool. There are four key features being implemented:

1. Visualization of statistic characteristics of input data sets
2. Parameter selection
3. Results: Expected Transmission Commitment (ETC) statistics
4. Results: ETC confidence interval

This phase of the project is expected to be completed in 2014.

Dynamic Line Rating Pilot

As described in the 2013 Smart Grid Report, Idaho Power and the 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 kilovolt (kV) and 138 kV transmission lines between Hagerman, Bliss, and Glenns Ferry, Idaho.

Since last year's report, the pilot project has progressed with the installation of several new weather stations. INL is developing the software to calculate operating line limits and should be completed in 2014. Idaho Power/INL has begun to gather data to assess the potential to dynamically rate transmission line operating limits in the Hells Canyon area. Data gathering is expected to continue through 2014 and will be assessed by the end of the year. If necessary, additional data gathering may continue into 2015. Due to the extreme topology of the Hells Canyon area, this is a very challenging endeavor. Idaho Power and INL continue to work closely together to further this technology and approach.

For a more complete description of this project, Appendix C contains a paper written by the INL titled, "Dynamic Line Rating: Concept, Case Study, and Regulatory Review."

Figure 2. Dynamic Line Rating Equipment Installed in Hells Canyon

B. Substation and Distribution Network and Operations Enhancements

Transmission Transformer Geomagnetic Disturbance (GMD) Monitoring

As described in the 2013 Smart Grid Report, 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 with and creates variation in the earth's magnetic field that could potentially damage some electrical power equipment. This analysis has identified three Idaho Power substations that may experience GIC during a large GMD. Two GIC sensors have been installed to date. The data is periodically gathered and aligned with GMD events to assess if the event resulted in measureable GIC.

The Federal Energy Regulatory Commission (FERC) and North American Electricity Reliability Commission (NERC) have also begun to address GMD. In May 2013, FERC issued Order No. 779 directing NERC to develop reliability standards to address the potential impact of GMDs on the reliable operation of the Bulk Power System. FERC Order No. 779 issued directives to NERC to develop reliability standards in two stages. Stage 1 standards require applicable entities to develop and implement operating procedures that can mitigate the effects of GMD events. Stage 2 standards require applicable entities to conduct initial and ongoing assessments of the potential impact of benchmark GMD events on their respective systems.

Stage 1 standards have recently been approved under NERC Project 2013-03 Geomagnetic Disturbance Mitigation as NERC Standard EOP-010-1. The Stage 2 standards will be drafted as NERC Standard TPL-007-1. Experience gained through the model development and study process will be used to help develop the operating procedures required in EOP-010-1 and the transmission planning processes and procedures that will be required in TPL-007-1.

Conservation Voltage Reduction Enhancements

As reported in the 2013 Smart Grid Report, Idaho Power participated with 12 other utilities in the Northwest Energy Efficiency Alliance's (NEEA) 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 implemented a CVR program in 2009 at eight substations and is now in the process of measuring and analyzing the program's effects and determining how the program can be enhanced.

A more detailed description of Idaho Power's CVR Enhancements Project is included in the Future Smart Grid Investments section.

C. Customer Information and Demand-Side Management (DSM) Enhancements

Advanced Metering Infrastructure

In 2011, Idaho Power completed the installation of AMI hardware and software, an MDMS, a metering data warehouse, and approximately 500,000 digital smart meters (including 18,000 meters in Oregon) for a total investment of $73 million. The AMI system 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 (90 percent in Oregon). The remaining metered retail service customers did not meet Idaho Power's business case requirements at the time the implementation plan was initiated. Idaho Power continues to manually read meters in these locations and periodically reevaluates the business case for installing smart meter equipment in substations located in sparsely populated areas.

Idaho Power has begun leveraging the AMI system for uses beyond consumption data collection. These additional uses include:

- Outage Detection – If a meter stops communicating, a trouble order is issued.
- Partial Power Detection – The phase voltages on all three-phase services are measured three times a day. If one of the phase voltages shows as missing, a trouble order is initiated. It is often found that one of the phases is de-energized on the customer's premises.
- System Voltage Reads – Voltage data is collected three times a day at all active three-phase services and other locations as requested by company planning or field operations (currently 40,000 sites).
- Select Load and Voltage Studies – In place of installing additional field monitoring devices, voltage and load information can be collected upon request.
- Customer Load Control – The AMI system communicates commands to both the A/C Cool Credit and Irrigation Peak Reward demand response (DR) programs.
- Reverse Power Flow Detection – The AMI system detects unauthorized customer generation, attempted energy diversion activities, and metering errors.
- Transformer Rated Meter Installation Verification – Operations periodically validates system current and voltage.
- Investigations of non-communication issues have uncovered service issues including unintended distribution circuit field ties, distribution capacitor issues, distribution line regulator issues, overloaded circuits, and power quality issues.

Time Variant Pricing

Beginning in April 2012, Idaho Power invited Idaho residential customers through a direct mail offering to sign up for an optional Time Of Day (TOD) pilot plan. Invitations were sent to approximately 132,000 customers throughout the summer of 2012. The offering resulted in over 1,600 customers enrolling in the pilot. Descriptions of the pricing plan structure, marketing collateral, rollout plan, and preliminary study findings were compiled in June 2013 and were included in the Appendix of the 2013 Oregon Smart Grid Report. Idaho Power planned to perform a behavior impact study after participants had been on the plan for a full year.

In July 2014, Idaho Power concluded the final impact study of the residential TOD pilot. This customer behavior study evaluated how the TOD pricing impacted energy consumption for participants in the plan. Participants' response to the TOD pricing signal was determined using a quasi-experimental study design structure with a TOD participant treatment group and a closely matched non-participant control group. The study timeframe included participant usage for the 12 months prior to when participants enrolled in the plan (April 2011 through March 2012) and 12 months after participants signed onto the plan (September 2012 through August 2013). The study used a two-tier stratification approach to obtain data for participants in four different usage categories to allow mapping of response rates to total population results. Idaho Power also calculated the billing revenue impact of this pilot by calculating a shadow bill for each customer on the TOD pricing plan versus the standard residential three-tiered pricing plan.

Key findings are summarized below:

<u>Overall Conservation</u>

- There was no statistically significant change in overall energy consumption observed in the study participants on the TOD rates.

<u>Overall Shifting of kWh</u>

- For the study group as a whole, the data analyzed showed a ***reduction*** in energy use from peak time periods by the analyzed participants of the pricing plan versus the control group. All but two months out of 12 months showed statistically significant reductions in energy use during peak periods. Over the 12-month study period this combined reduction in peak time period consumption was approximately 3 percent of total kWh use.
- For the study group as a whole, the data analyzed showed an ***increase*** in energy use during off-peak time periods by the analyzed participants of the pricing plan versus the control group. Five months out of the 12 months showed statistically significant increases. During the 12-month study period this combined increase in off-peak time period consumption was approximately 1 percent of total kWh.
- Figure 3 below graphically shows these results. The red bars show, in kWh, the estimated increase or decrease of usage by month and time of day of the TOD pricing plan participants. The left axis indicates the peak and off-peak results panels of the graph. The top half of the chart shows the average kWh reduction of peak time block usage. As can be seen on the chart, every month shows a reduction in usage from approximately -8 kWh (January) to approximately -26 kWh (month). The light grey bars behind the red bars represent a "not significant" band. Where the red bar does not extend beyond the light grey bar, then the estimated increase or decrease is small enough that it is within the range of what we might expect to see due to normal random variation and is not statistically significantly different from zero. Where the red bar extends beyond the light grey bar behind it, the results for that month are statistically valid at the 90 percent confidence interval. The bottom half of the chart shows the average kWh increase (or

reduction for December and February) of off-peak time block usage. Although in 10 months out of the year the average off-peak usage of participants increased, only in five of these months were the results statistically significant.

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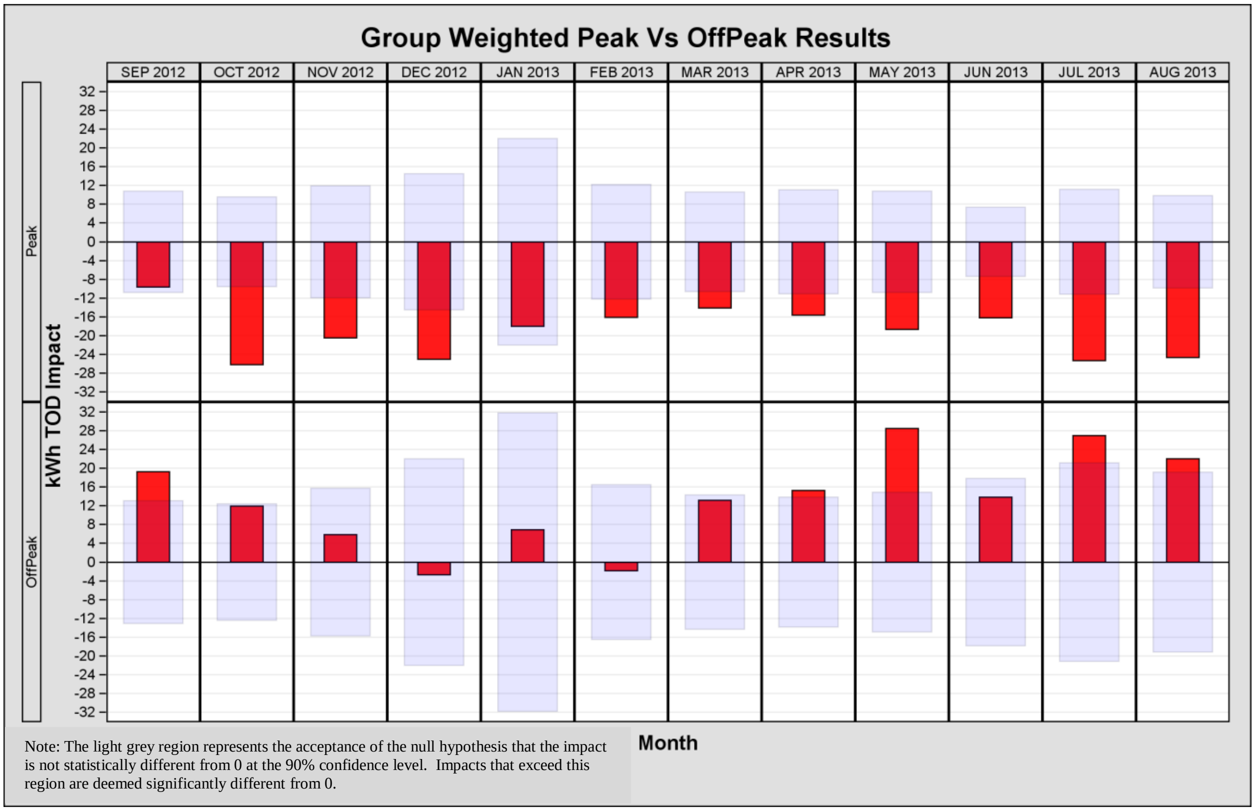


Figure 3. Group Weighted Peak Versus Off-Peak Results

Response Rate

- The overall response rate to the residential TOD pricing pilot plan solicitation was 1.3 percent.
- Study findings indicate that if the company were to expand the TOD offering to the remainder of the residential customer population across the company's service area using the same parameters and in exactly the same manner as in the TOD pilot, approximately 4,000 additional customers would likely volunteer to participate.

Billing Impact

- The study estimates that there was a revenue reduction of $119,000 when the actual TOD energy billings of all TOD pilot participants were compared with standard plan shadow energy bill calculations for all TOD pilot participants during the 12 months of the study, September 2012 through August 2013.

The company's evaluation and future plans for the TOD pricing plan are described in Section V, Targeted Evaluations. Appendix D contains the Time Of Day Final Study Report.

myAccount

As a way to empower customers to make informed choices about their energy use and to use energy wisely, to increase customer on-line transactions, and encourage customers to access their hourly AMI data, Idaho Power examined how the on-line tool, Account Manager, could be made more effective. In April 2014, the company launched an awareness campaign for the Account Manager on-line tool was launched. The focus was to drive more customers to register and to increase usage by those already registered.

Through customer research, Idaho Power learned many customers were confused with the Account Manager name and employee focus groups results indicated that the name "My Account" was more appealing. They also confirmed the timing should be in conjunction with the awareness campaign. Following an extensive evaluation of the impact a name change would have on the company's website, social media, existing publications, and other customer facing communication, the decision was made to implement the change.

The ongoing campaign focuses on three key messages related to the benefits of using myAccount: Pay Your Bill, Get Account Information, and Understand Your Use. The campaign shows a variety of images representing our customers — by age, professions, or targeted customer groups.

The new name now appears on Idaho Power's website and social media sites. The awareness campaign began in the May issue of Connections with myAccount benefits noted on customers' bills and envelopes. As the campaign rolls out, instructional videos, advertising, a brochure, and updates to presentations and other existing materials will be utilized. Throughout the year, there will be ongoing myAccount reminders, with emphasis prior to high bill periods. An Idaho Power Connections article concerning myAccount can be found at:
https://www.idahopower.com/pdfs/newscommunity/News/CustomerConnection/201405.pdf

Figure 4. Web Promotion Icon

As depicted in Figure 5, customer registrations during April – June 2014 were higher than during the same period last year when Idaho Power was not advertising sign-ups (beyond the bill and website).

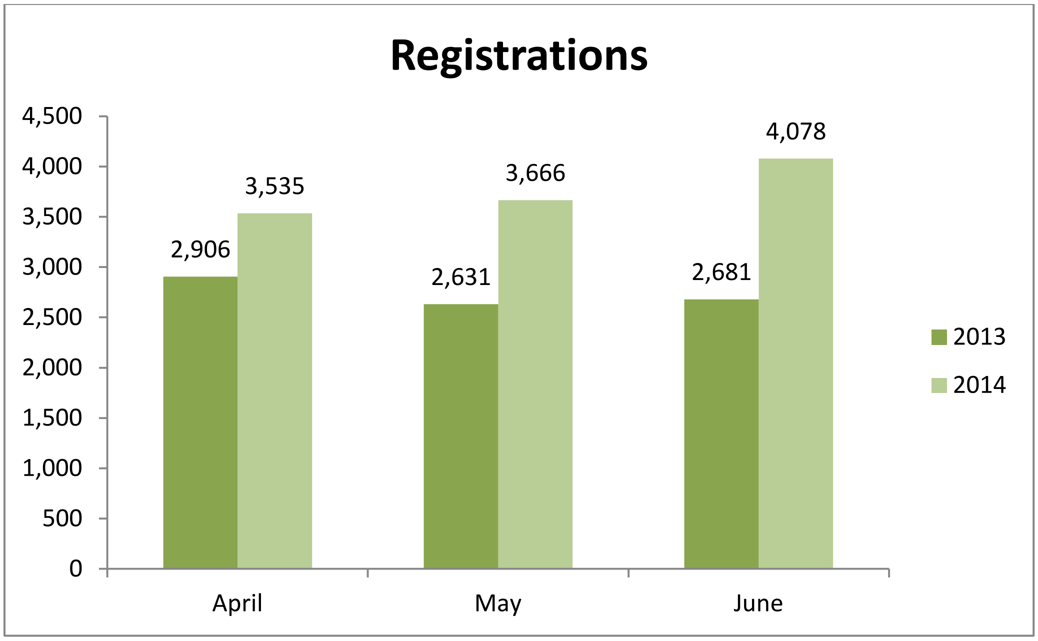


Figure 5. myAccount Registrations April – June 2013 Compared to April – June 2014

Direct Load Control

Idaho Power has offered optional direct load control, or DR, programs since 2004 and to all of its customer segments since 2009. The company has offered an air conditioning (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 power line carrier (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.

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.

During 2014 approximately 2230 customer sites were enrolled in the Irrigation Peak Rewards program, of these 31 are located in Oregon. Irrigation Peak Rewards was used three times during the summer of 2014, on July 2, 10, and 14. Preliminary results indicate the program's peak reductions at generation level was 286 M July 2, 294 MW July 10, and 275 MW on July 14.

FlexPeak Management

FlexPeak Management is a voluntary program designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak days. Participants are notified of a demand reduction event two hours prior to the event and in most cases reductions are achieved by the participants manually turning off equipment or otherwise changing their operations. The program objective is to reduce the demand on Idaho Power's system during periods of extreme peak electricity use.

Ninety-four participant sites were enrolled in FlexPeak Management in 2014. FlexPeak Management was used three times during the summer of 2014, on July 14, 31, and August 11. Preliminary results indicate the program's maximum peak reductions at generation level were achieved on July 14 and again on July 31 at 32.5 MW of load reduction.

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.

Approximately 31,539 PLC controlled switches are installed on customers' A/C units in Idaho Power's service area. Of these, 392 are installed in Oregon. These switches allow Idaho Power to cycle customers' A/C during a cycling event. A/C Cool Credit was used three times during the summer of 2014. Preliminary results for the program's maximum load reduction at the generation level were 42.94 MW on July 14, 29.59 MW on July 31, and 34.78 MW on August 11.

Irrigation Load Control Pilot

Idaho Power predominantly uses cell phone and web-based technology to enable the company's Irrigation Peak Rewards program. The objective of the ILC Pilot is to investigate using 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 American Reinvestment and Recovery Act (ARRA) Smart Grid Investment Grant (SGIG), Idaho Power began conducting a pilot using grid-enabled PLC communication that would provide a reduced cost and more secure environment for program communication. The company currently has 130 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.

In 2014, Idaho Power resolved a few installation issues and utilized the AMI-enabled technology successfully at the sites on which it was installed. Overall, Idaho Power has proven it is a viable method; the load control devices will work on irrigation installations and can be used in the Irrigation Peak Rewards program. In the future, Idaho Power will continue to evaluate whether to fully move to this technology for the program or stay with the cell phone technology.

D. Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool (RIT)

As reported in last year's smart grid report, the Idaho Power SGIG funded the RIT project. The RIT project is intended as a set of 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.

In 2014, the RIT was split into two tools: the Wind Forecast Tool and the Load Forecast Tool. A number of enhancements have been made to the original RIT in 2014 and are described in Section IV.

Photovoltaic (PV) and Feeder Peak Demand Alignment Pilot

As discussed in last year's report, Idaho Power has installed three solar-intensity monitoring stations along a distribution feeder to determine the impact of installing PV panels to maximize PV output with feeder peak demand. An update concerning this pilot project can be found in section IV.

Renewable and Other Energy Contracts

Idaho Power purchases wind generation from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project – the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of August 31, 2014, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW and an additional 50 MW of CSPP wind power projects not on-line and scheduled to come on-line by year-end 2016. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of generation from other CSPP and non-CSPP renewable generation projects, such as biomass, solar, small hydroelectric projects, and two geothermal projects. As of August 31, 2014, Idaho Power has signed CSPP-related agreements in both Oregon and Idaho with terms ranging from one to 35 years as set forth in the following table.

Table 1. CSPP-Related Contracts

Status	Number of CSPP Contracts	Nameplate Capacity (MW)
On-line as of August 31, 2014	104	781
Contracted and projected to come on-line by year-end (2016)	18	240
Total under contract	122	1021
Oregon Contracts	17	131
Idaho Contracts	105	890

Net Metering

As of August 31, 2014, Idaho Power's net metering service consisted of 464 active systems, with applications pending for an additional 37 systems. Cumulative nameplate capacity from active systems totaled 3.28 MW, with an additional 0.379 MW associated with pending applications, for a grand total of 3.66 MW. The majority of net metering systems are solar PV at 2.95 MW, followed by wind at 0.56 MW, and small hydro/other at 0.15 MW.

The tables below provide the total number of active and pending net metering systems and nameplate capacity by resource type, jurisdiction, and customer class.

Table 2. Number of Net Metering Systems - Pending and Active as of August 31, 2014

	Solar PV	Wind	Hydro/Other	Total
Idaho				
Residential	324	60	6	390
Commercial & Industrial	84	9	4	97
Irrigation	-	1	-	1
Total Idaho	**408**	**70**	**10**	**488**
Oregon				
Residential	3	2	-	5
Commercial & Industrial	6	-	-	6
Irrigation	2	-	-	2
Total Oregon	**11**	**2**	**-**	**13**
Total Company				
Residential	327	62	6	395
Commercial & Industrial	90	9	4	103
Irrigation	2	1	-	3
Total Company	**419**	**72**	**10**	**501**

Table 3. Nameplate Capacity (MW) - Pending and Active as of August 31, 2014

	Solar PV	Wind	Hydro/Other	Total
Idaho				
Residential	1.30	0.34	0.06	1.71
Commercial & Industrial	1.38	0.18	0.09	1.65
Irrigation	-	0.04	-	0.04
Total Idaho	**2.68**	**0.56**	**0.15**	**3.39**
Oregon				
Residential	0.01	0.00	-	0.01
Commercial & Industrial	0.14	-	-	0.14
Irrigation	0.11	-	-	0.11
Total Oregon	**0.26**	**0.00**	**-**	**0.27**
Total Company				
Residential	1.31	0.35	0.06	1.72
Commercial & Industrial	1.52	0.18	0.09	1.79
Irrigation	0.11	0.04	-	0.15
Total Company	**2.95**	**0.57**	**0.15**	**3.66**

In terms of growth, Idaho Power's net metering service continues to expand. The chart below details cumulative net metering system counts from 2002 to year-to-date 2014.

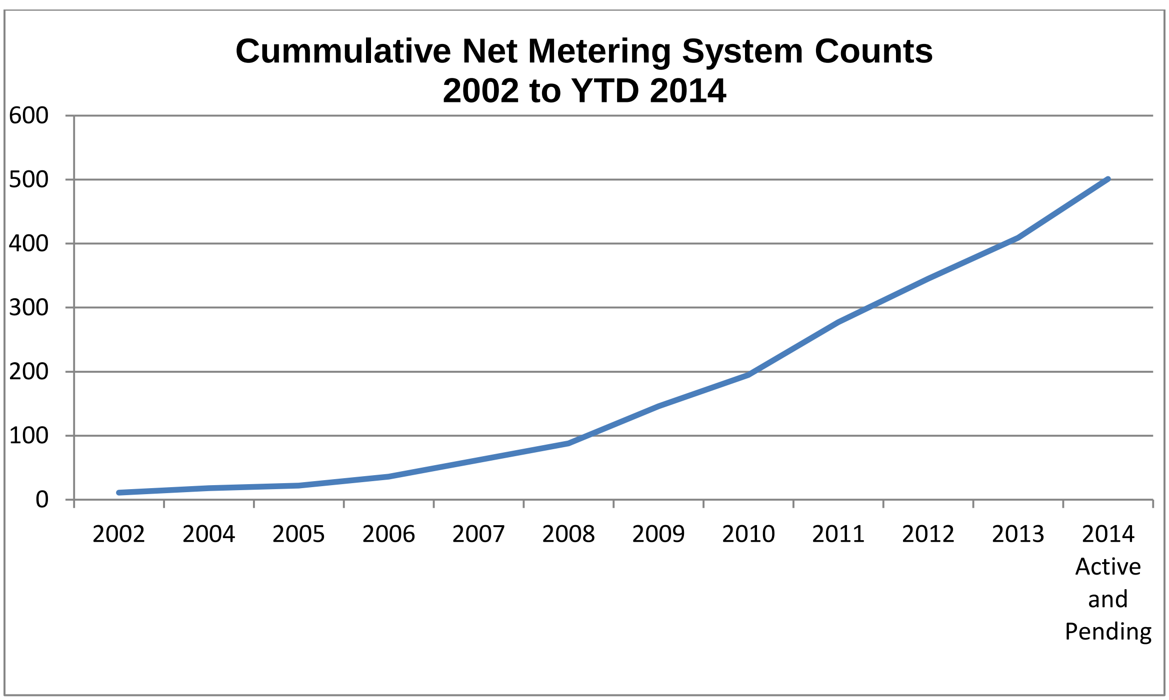


Figure 6. Cumulative Net Metering System Counts 2002 to Year-to-Date 2014

The chart below details cumulative capacity growth from 2002 to year-to-date 2014.

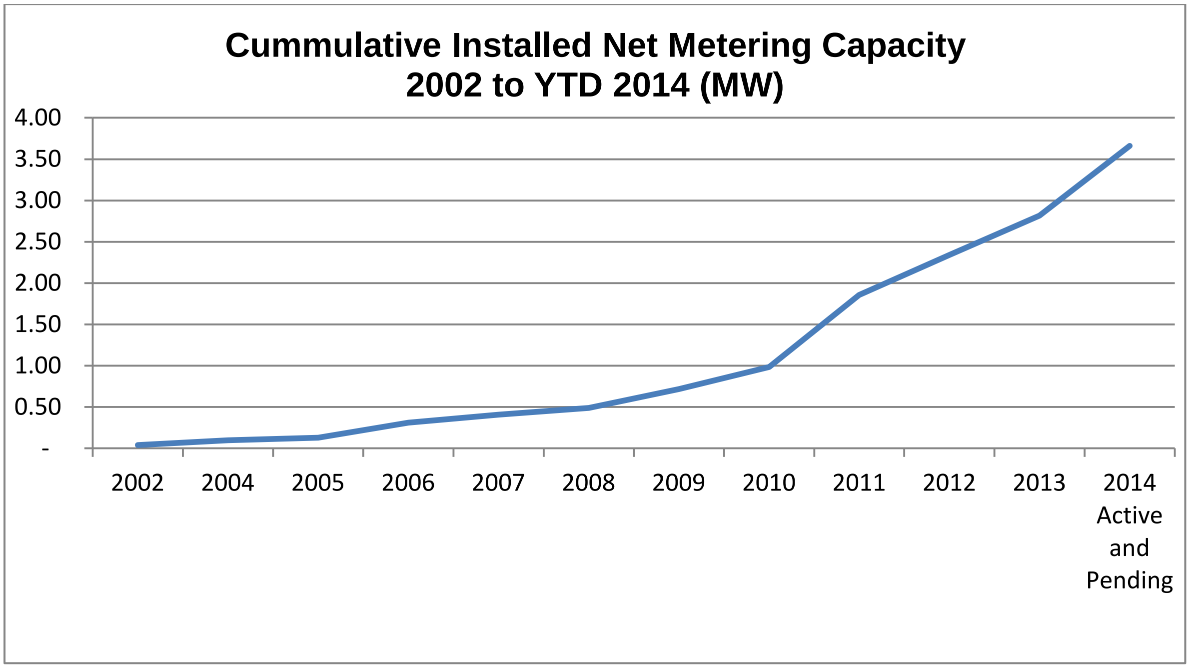


Figure 7. Cumulative Installed Net Metering Capacity 2002 to Year-to-Date 2014 (MW)

The exponential growth in net metering service since 2002 demonstrates how the company's grid is evolving, and underscores the importance of ongoing evaluation of the associated service provisions and pricing to ensure that Idaho Power continues to offer safe, reliable, and fair-priced electrical service.

E. General Business Enhancements

Idaho Power Enterprise Data Warehouse (EDW)

The EDW provides an analytic database to store customer and meter data. The EDW supports the company's analytical and reporting needs by providing a location combining information from both legacy and current customer information systems. It also ensures that reporting activities do not adversely impact performance on the metering, MDMS, and Customer Relationship and Billing (CR&B) source systems.

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 combines customer data extracted from CR&B, as well as the legacy customer information system (CIS+), for reporting and analysis. This phase began with the implementation of CR&B on September 1, 2013. In December 2013, DSM information was added to the EDW. In June 2014, access to basic customer information for approved users was enabled. Additional releases to populate required customer information into the data warehouse are planned for the remainder of 2014 and into 2015.

Idaho Power currently has daily and hourly energy-use data stored for all AMI metered service points. Basic customer information data including Customer Master, Premise, Billing, and address information is also stored in the EDW. The EDW has enabled:

- Customer portal viewing of energy use via myAccount
- Available data for internal load analysis and development of broader system analysis capabilities
- Energy-use data available to internal functions with approved business access
- Basic customer information available for viewing through a portal with approved business access
- Ad-hoc access granted to authorized employees for approved business access

III. Future Smart Grid Investments

This section describes smart grid investments and meetings to be undertaken over the next five years (including pilots and testing). In addition to reporting requirements, this section serves as a high level strategic document for Idaho Power to plan its smart grid projects. As such, the format of this section is different from the other sections in this report. The description for each of the following projects is laid out in the following format:

Present – What Idaho Power's present system looks like with regard to the individual project described.

Objective – What the objective is of the individual project described.

Pilot or Project Description – A description of the proposed or existing pilot or project.

Benefit – How the investment will reduce costs, improve customer service, improve reliability, facilitate demand-side and renewable resources, or provide other system benefits. Also, how it fits with the annual construction budget for major distribution and transmission investments.

A. Transmission Network and Operations Enhancements

Transmission Situational Awareness Oscillation Monitoring Pilot

Present

The Washington State University (WSU) Oscillation Monitoring System software monitors system-wide oscillations using Idaho Power Phasor Measurement Unit (PMU) data. The Oscillation Monitoring System software identifies the oscillation mode frequency(ies), damping ratio (signal reduction factor), mode energy in the signal, and the confidence level or quality of the signal. Idaho Power has 24 PMUs at 14 substations collecting PMU data for oscillation monitoring within the Oscillation Monitoring System software. The majority of the effort to date has been focused on using archived PMU data within the Oscillation Monitoring System software both for software development and for analysis of system performance.

Idaho Power is also studying the option of integrating the output data of the WSU Oscillation Monitoring System software into the OSIsoft, LLC/PI enterprise infrastructure management software platform (OSI/PI) real-time data management system for visualization of the Oscillation Monitoring System results for use by transmission operators and transmission operations engineers in order to increase transmission system situational awareness and for system planning engineers to conduct post-event analysis. The OSI/PI software is commercially available software that Idaho Power already uses which could display the PMUs signals and the processed data of the Transmission Situational Awareness Oscillation Monitoring System software. Appendix E contains a presentation prepared as part of the North American SynchroPhasor Initiative.

Objective

The project objective is to install sufficient PMUs to identify and monitor system-wide oscillations. This would require monitoring interconnection points between Idaho Power and other utilities, as well as generation sites internal to the Idaho Power transmission system. The software would have the capability to identify power system oscillations using real-time PMU data and display the modes of oscillation, damping ratio, mode energy, and calculation confidence level. The software is also expected to use archived PMU data so modal analysis of system oscillations can be performed as part of a post-event analysis.

Pilot or Project Description

Idaho Power initiated the Oscillation Monitoring Project in 2012 in collaboration with WSU. The intent of the project and Oscillation Monitoring System software is to identify frequency oscillation modes, oscillation signal damping ratio and energy level, and present an indication of the severity of the observed oscillations. Additionally, the software also identifies a confidence level or accuracy estimation of the calculation results. The oscillation energy level can be used to determine potential sources contributing to the oscillations detected by the software. Idaho Power budgeted to install six additional PMUs at generation sites within the Idaho Power transmission system. The designs on these projects are expected to be completed in 2014 along with construction of the PMU panels with anticipated installation in 2015. These projects are intended to provide additional PMU measurements that can be processed by the Oscillation Monitoring System software in addition to the existing PMU signals to better determine potential sources of poorly damped oscillations detected by the Oscillation Monitoring System software.

Benefit

The Oscillation Monitoring Project identifies system-wide oscillations. One of the goals is to identify/distinguish between inter-area, inter-unit, and local-area oscillations. Some oscillations exist within the WECC system that do not present concerns because the known behavior of these oscillations is well damped. Identification between known oscillation modes, changes in the damping energy of known oscillation modes, identification of new oscillation modes and their associated damping behavior, as well as potential sources of poorly damped oscillations, provide the opportunity for early warning of potentially unstable power system conditions. Early warning of poorly damped oscillation modes provides transmission operators the opportunity to make system adjustments to improve transmission system stability. An additional benefit of oscillation monitoring is the ability to perform post-disturbance analysis of power system oscillations and overall system performance.

Transmission Situational Awareness Voltage Stability Monitoring Pilot

Present

The WSU Voltage Stability Monitoring System (VSMS) software monitors voltage and current signals to determine substation voltage stability indices. Developed at WSU, the software calculates the change-in reactive power with respect to the change-in voltage or the delta-Q/delta-V (dQ/dV) sensitivity for each network branch element monitored by the software. A voltage stability index for a substation bus is determined by summing the dQ/dV sensitivities of all the branches at a single substation bus together to create composite dQ/dV sensitivities for each substation monitored by the VSMS software. The only substation bus Idaho Power is currently able to monitor using the VSMS software is the Kinport substation 345 kV bus due to lack of PMU measurements of all network branches at other Idaho Power substations.

Objective

The project objective is to install sufficient PMUs to monitor voltage stability at Idaho Power substation buses. This requires PMU monitoring of the network branch elements (i.e., transmission lines, transformers, reactive compensation devices, etc.) at substation buses of interest for voltage stability analysis using the WSU VSMS software. The expectation for the VSMS software would be to monitor real-time voltage stability, as well as have the capability to utilize archived PMU data to perform post-event voltage stability analysis. System operators could utilize real-time voltage stability data for transmission system situational awareness and system planners could utilize archived PMU data for voltage stability pre/post disturbance analysis.

Pilot or Project Description

Idaho Power initiated the Voltage Stability Monitoring Project in 2012 in collaboration with WSU. The intent of the project and the VSMS software are to monitor transmission system voltage stability and provide indicators of substation buses approaching unstable operating points. Idaho Power will gain six additional PMUs for voltage stability monitoring in 2015 by using signals from the new PMUs described in the Oscillation Monitoring Pilot described above. The addition of the six PMUs provides the capability for voltage stability monitoring at four 230 kV substation buses and two 138 kV substation buses in addition to the presently monitored Kinport substation 345 kV bus.

Benefit

The voltage stability monitoring program identifies the change in reactive power with respect to the change in voltage or dQ/dV sensitivity. The VSMS software monitors the dQ/dV sensitivity of each branch element that has available PMU measurements. A composite voltage sensitivity index is calculated for a substation bus by summing the sensitivities of each monitored connected branch element. If system conditions are approaching an unstable operating point, the VSMS software would be able to provide situational awareness to Idaho Power transmission operators. One project benefit is increased situational awareness of transmission operating conditions which would allow Idaho Power to detect unstable operating conditions in real-time so system adjustments could be made to return system conditions to stable operating points and thus improve transmission system reliability. A secondary benefit provided by the project is that Idaho Power would also have the capability to perform post-event analysis that could lead to the development of new or improved operating procedures when operating near voltage stability limits.

Transmission Situational Awareness Grid Operator's Monitoring & Control Assistant

Present

Idaho Power system operators rely on day-ahead power flow analysis and some real-time analysis tools to manage the grid.

Objective

The goal of this project is to advance grid reliability by improving the quality and use of the synchrophasor data received from more than 584 PMUs installed throughout the Western Interconnection by participating utilities by developing an application to manage the grid.

Pilot or Project Description

Idaho Power, Southern California Edison, Peak Reliability, California Independent System Operator, Bonneville Power Administration, San Diego Gas and Electric, and V&R Energy have received a U.S. Department of Energy (DOE) research and demonstration grant for a new synchrophasor-based software application "Grid Operator's Monitoring & Control Assistant." See Appendix F for Peak Reliability's press release. The funding matches dollars committed by the seven participants to extend and deploy synchrophasor technologies. Peak Reliability will use the grant to improve the quality and use of the synchrophasor data it receives from the PMUs referenced above.

The proposed software application will consist of the following major components:

a) Use of Linear State Estimator (LSE) for the following purposes:
    - Validating the results of conventional model-based SE
    - Determining the observability of the network in terms of voltage stability
    - Utilizing cases created by LSE for voltage stability analysis
b) Automatic computation of advisory optimal corrective actions for voltage stability preservation.
c) Computing phase angle difference limits in real-time using a new methodology for line/path stressing based on maximized loading of transmission lines/paths.
d) Displaying easy-to-understand visualization of synchrophasor data, voltage stability analysis results, and optimal corrective actions on a custom-built situational awareness wall.

V&R Energy will perform a demonstration of the software tool. Idaho Power will prepare and provide data to V&R Energy, respond to the data-related questions, review and provide feedback on the functionalities of the tool, test the software tool in-house, and attend required meetings and training sessions on the software application.

Benefit

The software will validate the SE, perform computation of corrective actions to maintain voltage stability, compute phase angle difference limits, and provide operator visualization of synchrophasor data. The overall goal of the project is to improve grid reliability.

B. Substation and Distribution Network and Operations Enhancements

Substation Fiber-Based Protection and Control Pilot

Present

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. These copper control cables represent a significant percentage of the overall cost of a new substation.

Objective

Newly built Idaho Power substations would use fiber optics in lieu of copper wires to connect pieces of substation yard equipment to the control building for protection and control.

Pilot or Project Description

Idaho Power and Schweitzer Engineering Laboratories 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. The fiber optic-based protection and control demonstration project at Hemingway substation is progressing. The conceptual design is complete and the various components are being selected. The digital equipment needed is being developed and will soon be available. Construction is anticipated to begin in fourth quarter 2014 with the fiber optic cable, yard cabinets, and control rack installation. This project will not only demonstrate the protection and control over fiber optic concepts, but will implement very accurate time distribution over a highly reliable fiber optic network – a necessary development for this standards-based approach to proceed.

Benefit

Once demonstrated, not only will this technology potentially reduce costs for Idaho Power and its customers in future installations by decreasing the amount of copper wire installed, but it could prompt industry-wide adoption of this approach.

Automated Volt/VAr Management System (VVMS) Pilot

Present

Idaho Power currently operates an ACC system that effectively controls reactive power flow (Volt-Ampere reactive power or VAr) at substation transformers by controlling distribution feeder capacitor banks. In place since the late 1990s, the ACC system is installed at 76 distribution substations. It uses one-way radio communications to command capacitor banks on and off with the goal to be near unity power factor at the substation transformer at all times with a slightly leading power factor at heavy load and a slightly lagging power factor at light load. Control is performed via computers at each substation; the system is not currently centrally controlled.

As effective as the system has been, the aging ACC system components are beginning to fail leading to a system that is progressively less reliable. Direct replacement of the components is difficult because many are obsolete and no longer vendor-supported. Additionally, the present system is not suited to future growth.

Objective

Idaho Power's distribution system would have fully automated capacitor banks communicating two ways with a centralized control system. The capacitor banks would be controlled via a dedicated VVMS which may be part of a complete Distribution Management System (DMS). The VVMS would monitor reactive power flow at the distribution substation level and would maintain near unity power factor (at the substation) in order to support the reactive power requirements of the bulk electrical system. Additionally, voltage would be monitored along distribution feeders and capacitor banks would be switched on and off in a coordinated fashion to maintain adequate voltage level to customers while maintaining adequate reactive power flow.

New solid state reactive compensation devices may be installed on the customer side of service transformers to provide voltage support in areas where low voltage exists. Additionally, new solid state voltage regulators may also be placed on the customer side of service transformers that would be able to both buck and boost voltage levels in response to voltage variations caused by customer-owned distributed generation devices.

The entire VVMS would operate to smooth voltage variations along a distribution feeder caused by variable and intermittent distributed generation sources at customer sites.

Pilot or Project Description

Idaho Power has identified a project beginning in 2015 or 2016 that will pilot a new central server-based VVMS combined with bidirectional communications to replace the existing ACC system. The VVMS will control distribution substation transformer LTCs, line regulators, and distribution capacitor banks. The piloted system will be chosen with the intent of integrating it into a future, as yet to be defined, DMS. The pilot is expected to last one to two years.

Benefit

In order to provide customers with adequate voltage to operate their devices, it is important to control reactive power flow and voltage on feeders. Utilities have traditionally done this by manually switching capacitor banks on and off seasonally and installing voltage regulators at strategic locations along distribution feeders. More recent technology allows utilities to automate and communicate with the capacitor bank switching and voltage regulator controls thus flattening the voltage profile along the feeders. Additionally, this communication and automation will provide the means Idaho Power needs to more efficiently integrate small distribution system-based generating customers.

Conservation Voltage Reduction Program Enhancement Project

Present

CVR is a term used to describe a method for decreasing energy use and/or demand by decreasing the voltage on a feeder. By reducing feeder voltages by a minimal amount, significant energy can potentially be saved. Idaho Power implemented a CVR program in 2009 at eight substations. This CVR program was instituted at minimal cost by simply changing the tap settings on distribution substation transformer LTCs. Only a small number of feeders qualify for CVR using this method because of low voltage issues that can result at certain locations along the feeder. Also, by controlling only at the transformer LTC, all the feeders connected to an individual transformer must qualify for CVR status. So, even if only one feeder has low voltage issues, the entire group of feeders connected to a given transformer would not qualify.

Idaho Power has identified a number of other feeders that could qualify for CVR if upgrades were made to either the conductors or the voltage regulation equipment. However, these upgrades are expensive and the benefits have not been fully quantified such that they can be applied to new feeders.

Objective

CVR would be in effect at all feeders where it can be effectively and cost-efficiently implemented. The CVR would be dynamically controlled such that voltages on feeders are minimized while maintaining customers' voltage levels meet National Service Voltage Standard (ANSI C84.1). CVR would also be able to reduce demand on feeders during peak load periods in response to capacity requirements. Voltage control on the feeders would be accomplished in a coordinated fashion by substation transformer LTCs, feeder capacitor banks, voltage regulators, and low voltage control devices located on the secondary side of service transformers. CVR may be controlled by an application within Idaho Power's Volt/VAR Management System, a dedicated system operated under a DMS or a standalone CVR management system.

Solid state reactive compensation devices would be installed on the customer side of service transformers and would be used to provide voltage support in areas where less than adequate voltage may exist.

Pilot or Project Description

Idaho Power has initiated a project that began first quarter 2014 and is expected to be complete mid-2016 to:

1. Validate energy savings associated with CVR using measured instead of modeled values
2, Quantify the costs and benefits associated with implementing CVR
3. Determine methods for expanding the CVR program to additional feeders
4. Pilot methods for making Idaho Power's CVR program more dynamic
5. Determine methods for ongoing measurement and validation of CVR effectiveness

The outcome of this project would be a cost-effective CVR program that can be more fully utilized across the Idaho Power system. It is anticipated that control of the CVR program would be embedded in the new VVMS previously described. The project plan for the CVR Enhancement Project can be found in Appendix G.

Benefit

If successfully implemented, CVR can reduce customer energy use thus saving customers money. In concert with a Volt/VAr Management system, it can also act to flatten the voltage profile along a feeder thus providing a more stable voltage at customers' premises and potentially lowering feeder losses.

Edge of Network Grid Optimization (ENGO) Solid State Reactive Power Compensation Device Pilot

Present

Idaho Power currently provides voltage support on feeders using capacitor banks and voltage regulators. The capacitor banks do not dynamically react to voltage change. The voltage regulators react to voltage changes on the feeder and attempt to maintain a stable voltage. However, there are still areas on some feeders where low voltages may occur and the utility's normal recourse is a costly feeder upgrade.

Objective

Areas of low voltage on feeders with an otherwise good voltage profile would be resolved using small, inexpensive, dynamic voltage support devices. These devices would be located on the customer side of service transformers and would react to voltage changes in a sub-cycle manner.

Pilot or Project Description

Varentec's ENGO unit is a solid state (static) VAr compensation device that provides dynamic or variable voltage control at the secondary side of distribution service transformers. These units have been deployed in pilot projects by a few utilities.

In 2014, Idaho Power deployed a number of ENGO units to evaluate their viability for voltage support on feeders with spot voltage problems with the intent to use ENGO units in place of more expensive solutions such as reconductoring or small voltage regulators. The ENGO units may also be piloted on feeders presently involved in the CVR project where a more dynamic or aggressive voltage setting is desired. Additionally, the evaluation included in this pilot will include determining what, if any, affect the ENGO units have on Idaho Power's Two-Way Automated Communication System communications signal used by the AMI system. The pilot project is expected to be complete at the end of 2014, though the devices may be moved to other feeders in 2015 to further evaluate their effectiveness. The project plan for the ENGO Project can be found in Appendix H.

Benefit

If successfully implemented, ENGO devices can flatten the voltage profile at customers' premises and may be used to defer or replace more expensive methods for resolving voltage issues.

Figure 8. ENGO Unit Being Installed Beneath a Distribution Transformer

Distribution System Communications Strategy

Overview

Idaho Power currently communicates with a diverse group of distribution system devices, i.e., reclosers, capacitor banks, line fault indicators, meters, and outage monitors using a variety of communications systems. These systems include licensed radio frequencies, public unlicensed radio frequencies, telecommunication company landlines, cellular systems, and PLC. The communication system used is evaluated based on the control or data requirements for the various distribution system devices. The need for one-way or two-way communications, data transfer, and control requirements (bandwidth and speed) dictates which communication system most cost-effectively fits the need.

The project below is an example of this strategy.

Ability of the AMI System to Control Line Devices

Present

Idaho Power currently communicates with the capacitor banks associated with the ACC program using one-way radio communications. As this program shifts into a more robust Automated Volt/VAr Management System, two-way communications will become necessary.

Objective

Idaho Power will test its AMI system to determine if it has the capability to perform simple command and control functions on distribution capacitor banks.

Pilot or Project Description

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

Benefit

Using Idaho Power's AMI system to communicate with capacitor banks could provide a robust communications solution that is more resistant to obsolescence than the present system. Using a communications system that is already installed everywhere Idaho Power has AMI would provide control of capacitor banks without the need to install additional communications equipment in substations.

Replace the Existing Outage Management System

Present

Idaho Power's existing OMS is aging and is no longer supported by the original vendor. In 2010, Idaho Power started the effort to select a vendor and implement a new OMS. Following a market search and analysis of several request for proposals, 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 and will begin work again in late 2014.

Objective

Idaho Power requires an OMS that can integrate into existing control and operating software platforms and that can be used with Idaho Power's geographical information system. The OMS would be used primarily to efficiently and accurately capture customer outage information that would be used for coordinating restoration work and reporting activities.

The company desires the OMS to enable a direct interface to Idaho Power's meters to validate outage scope and restoration. Through the OMS application, OMS operators will query specific meters in suspected outage areas. The OMS application will provide outage data presentation through direct communications with AMI meters, verify the scope of customer-reported outages, and provide confirmation of power restoration. Additionally, Smart Grid Monitoring (SGM) System devices (described in the Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality project below) may be used for advance notice of outages. Verification of an outage prior to dispatching resources to repair the outage will allow the repair crew to be more efficient in terms of customer restoration times, and confirming restoration will eliminate the chance of repair crews leaving the area before service is restored to all customers.

Pilot or Project Description

This project will develop the requirements and operational characteristics of a new OMS using previously developed requirements and more up-to-date information. Because of advancements in OMS software platforms since 2012, this project will begin the vendor search anew. It is anticipated that vendor selection will occur first quarter of 2015 followed by implementation during the remainder of 2015. Project completion is projected to be mid-year 2016.

Benefit

A new OMS platform will aid in customer service restoration after power system interruption events. It will allow more efficient use of repair crews and thus decrease costs.

Implementation of Automated Connect/Disconnect Capability at Selected Locations through the AMI System

Present

Idaho Power's AMI project that concluded in 2011 did not include the installation of remote controlled connect/disconnect switches. Idaho Power was not able to justify the cost of installing these switches at all metering points on its distribution system. Company representatives continue to physically visit customer service locations to manually connect and disconnect services as needed.

Objective

Idaho Power has always recognized the capability of the AMI system to remotely control service connect/disconnect switches. After the initial AMI installation, the company analyzed the costs and benefits of installing AMI controlled service connect/disconnect switches at a select number of locations. The Company believes that the capital costs are more than offset by eliminating manual corrects/disconnects at locations that have multiple visits to manually connect or disconnect service each year.

Pilot or Project Description

Approximately 14,500 residential service locations in Idaho Power's total service area (772 in Oregon) have multiple actual connect/disconnect events each year. The company has begun replacing the current meters at these locations with new meters equipped with remote controlled connect/disconnect switches. Meters removed from service will be used for new business and maintenance activities, reducing the need to purchase additional standard AMI meters. Below is a list of project milestones:

1. Begin installing remote connect/disconnect AMI meters - April 21, 2014
2. Complete installations of remote connect/disconnect AMI meters - December 31, 2014
3. Implement the necessary Information Technology (IT) system configuration to support the connect/disconnect process - February 1, 2015
4. Hold stakeholder meetings and obtain necessary regulatory approvals for the process changes required to implement automated connect/disconnect capability in Idaho - Fall 2014/Winter 2015
5. Implement the automated connect/disconnect process - Spring 2015

Benefit

By installing this technology as described, Idaho Power expects to realize the following benefits:

1. Reduce the annual cost of connecting and disconnecting services
2. Improve customer service by consistently completing the connect/disconnect function in a more timely manner

3. Remove a potential safety risk for employees traveling to customer locations, accessing service locations and removing and installing energized meters as is currently done for connect and disconnect activities
4. Reduce the environmental impact of driving hundreds of thousands of miles each year to perform this function manually
5. Gain experience with this capability and establish a foundation for evaluating the possibility of offering an optional prepaid service at some future date

Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality

Present

Formerly known as the Sentry System, Idaho Power has implemented an SGM System that monitors system reliability. The SGM System has approximately 1,400 monitored sites that record momentary and sustained outage activity. At present sustained outage notification from the SGM System is fed directly into Idaho Power's OMS which notifies operators when a sustained outage is detected. Once aware of the outage, the OMS operators can request a manual query of AMI meters in the affected area to more precisely identify the location of the outage.

In 2013, Idaho Power tested AMI integration with the SGM System and found that the systems can exchange sufficient data to provide the OMS with outage information related to event origination and tracking of outage restoration activity.

Objective

Idaho Power desires to more fully automate outage locating through the use of technology. The SGM System used in conjunction with the AMI system can quickly and accurately locate outages on the distribution system to improve system outage restoration efforts.

Pilot or Project Description

This project will develop an interface to allow the SGM system to identify a list of meters to be interrogated based on known system outages and/or restorations. The project will then enable the AMI System to interrogate the meters identified by the SGM and inform the OMS of any meters that remain in an outage condition. This will limit the need for manual query for outage scoping.

The project will enhance the work completed in 2013 to provide an SGM to AMI interface and will be ready for implementation by 2016.

Benefit

The main benefit will be improvement in system outage restoration performance. Additionally, this would allow Idaho Power to utilize momentary outages to locate open fuses if fuse saving is being implemented, or could be implemented, in areas to improve System Average Interruption Frequency Index (SAIFI). Currently, if a fuse tap is in an outage condition, Idaho Power relies on customer notification of the outage to begin restoration activities.

C. Customer Information and Demand-Side Management Enhancements

Customer Relationship Management

Present

Idaho Power desires to enhance current internal marketing applications and processes to increase its ability to effectively provide analytics, reporting, and information for communication efforts.

Objective

The objective of incorporating a single system, integrated with the CR&B system, will allow Idaho Power to manage and track customer interactions related to energy efficiency and other customer relations activities with the ultimate goal of increasing the effectiveness of Idaho Power's program and service offerings.

Pilot or Project Description

Using the CRM capabilities of the CR&B system, the CRM application will retrieve data from a variety of data sources (meter usage data, customer data, demographics, program data, etc.). The software will provide the ability to query and report both formally and ad hoc. Customer preference management (opt-out, marketing frequency, topic choice, etc.) will also be a component of the system.

Benefit

The information will allow Idaho Power to better market its customer programs and service offerings. Systematically using various sources of data to reach customers should result in reduced printing and postage costs through more effective customer segmentation and targeted marketing. The information will aid the company to reach customers more efficiently through the gradual shift to electronic channels such as email.

Integrated Demand Response Resource Control

Present

Idaho Power manages three DR programs as describe in Section II of this report. The dispatch associated with each program is unique to the program and requires various steps of generation dispatch employees utilizing multiple systems.

Objective

An opportunity exists to reduce operator confusion and gain efficiencies when dispatching DR programs during events.

Pilot or Project Description

The project would include a review of the potential to electronically tie each DR program's dispatch software into one software interface. If it is determined that electronically connecting the systems into one software is possible, then development of criteria for a customized front-end screen would take place. Functionality would also include the ability to manage individual customer opt-out by event.

Benefit

A single-interface dispatch solution would create efficiencies for dispatch employee training and knowledge through one system rather than three. It can also provide an environment where it is less likely for incorrect program dispatch to take place which can have direct impact on customer satisfaction with the program.

D. Distributed Resource and Renewable Resource Enhancements

Renewable Integration Tool: Potential Future Projects

Present

The Idaho Power SGIG funded the 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 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 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.

In 2014, the RIT was split into two tools: the Wind Forecast Tool and the Load Forecast Tool.

Objective

Idaho Power will be operating a fully functional RIT to allow grid operators and power supply transaction specialists to efficiently and reliably integrate variable renewable resources with traditional generation resources. The RIT will yield three wind forecast intervals: a short-term demand forecast, an enhanced regulating margin forecast, and a spinning reserve forecast.

Pilot or Project Description

Idaho Power has made the following changes or is considering the following projects for potential improvements of the RIT:

Incorporating new forecasting model types. Idaho Power continues to look for improvements to the current weather model, new weather models, and techniques to improve the wind forecast.

- Idaho Power now uses the Boulac microphysics package for the 6z and 18z model runs. Additionally, Idaho Power accesses the National Center for Atmospheric Research snow analysis data for model initialization. The University of Arizona is conducting research on both temperature and wind forecasts after a study uncovered a significant problem with the Global Forecast System snow forecasts in higher terrain. This was previously unknown in the modeling community and the University of Arizona will be working with the National Center for Environmental Prediction to determine how to correct this problem. The University of Arizona expects to publish its report sometime in 2015.
- Idaho Power has tested the model using 30 meter terrain resolution as it is believed that the present terrain resolution in the model significantly affects wind forecasts in mountainous terrain. Idaho Power will implement the new terrain resolution into the model later this year.

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 gauges and create an early warning system based on these observations.

Additional high-speed cutout warnings. To develop an algorithm to apply to all system wind developments that would use reasonable high-speed cutout indicators.

- Idaho Power is currently working on improvements to test in the fourth quarter of 2014.

Forecast refinements. Investigate several other weather parameters to determine correlations with wind generation. Some of these correlations may detect ramps or weather fronts, and others are related to generation accuracy.

Thunderstorm detection. Thunderstorms moving through the system cause rapid spikes in wind 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.

- A daily accuracy report was created which allows easier detection of forecasting issues.

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 generation facilities. The addition of new wind generation facilities into the RIT, although better, is still a slow process.

- Fewer new wind generation facilities are currently being developed. The only new wind generation facility in the near-term future will be in Baker County, Oregon.

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.

Benefit

A fully functional RIT (now known as Wind Forecast Tool and Load Forecast Tool) will allow grid operators and power supply transaction specialists to efficiently and reliably integrate variable renewable resources with traditional generation resources to meet customer loads.

E. General Business Enhancements

Upgrade the Mobile Workforce Management System

Present

Since 2007, Idaho Power has been using CGI Group's (CGI) 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 may improve the efficiency of field personnel.

Objective

Upgrade the existing version of PragmaCad to the latest version to maintain vendor support and realize the benefits of increased functionality that will improve the efficiency of field personnel.

Pilot or Project Description

Idaho Power plans to upgrade the existing version of PragmaCad in 2015.

Benefit

Upgrading the PragmCad to the latest version will improve the efficiency of Idaho Power's field personnel thus reducing costs.

Upgrade the Meter Data Management System

Present

The Itron Enterprise Edition (IEE) MDMS receives the raw data from the AMI system, ensures the accuracy and integrity of the data, and processes the data to the CR&B system and the EDW. The current version was installed in 2008 as a part of the AMI implementation. It is limited in its capability to handle unique pricing plans. In addition, the current version of IEE runs on the Windows XP operating system. Microsoft support for Windows XP is limited to security patches and incident support available on a case-by-case basis until June 2015. Maintaining continued support of the IEE client on machines with Windows 7 operating systems requires an upgrade of IEE.

Objective

Upgrade from IEE version 7.0 to the latest commercial release 8.1. Coordinating this project with the proposed effort to optimize the IEE and CR&B interface is the most efficient use of business and IT resources.

Pilot or Project Description

Upgrade the current version of IEE to the latest commercially available version of this software. Where possible, coordinate this project with the proposed effort to optimize the IEE and CR&B interface to best utilize the company's technical resources.

Benefit

Upgrading the current version of IEE from 7.0 to 8.1 will comply with Idaho Power's Enterprise Technology Advisory Board technology roadmap that seeks to achieve a sustainable technology portfolio capable of meeting the requirements of Idaho Power. Idaho Power will also take advantage of previously paid software maintenance fees that permit software upgrades without additional licensing costs. Software upgrades will ensure appropriate vendor support and increase potential customer billing and pricing options.

IV. SMART GRID OPPORTUNITIES AND CONSTRAINTS

This section describes other smart grid opportunities the utility is considering for investment over the next five to 10 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

All DOE ARRA smart grid grant projects are considered complete with no additional information to provide. This report represents Idaho Power's smart grid approach going forward.

Home Area Network (HAN)

Idaho Power is not currently using any 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 for the present time. Idaho Power provides energy management advice and data supporting third-party energy management systems.

Personalized Customer Interaction

Today, Idaho Power's customers can register and log-in to myAccount using the Energy Use Advising Tool to receive information regarding their energy use. Idaho Power envisions that its customers will want to use smart phones and tablets to inform them of energy use thresholds in their homes or businesses. Customers will want Idaho Power to proactively send them personalized information via text or phone applications that has been customized by the customer to thresholds the customer has determined. Upon receiving this information, the customer will be empowered through the technology to adjust energy using devices in their home or business to manage utility costs. Examples of applications in which customers will seek more interactive engagement include:

- Outage applications
- Energy management applications
- Mobile workforce management
- Business transactions

Idaho Power does not currently have established systems to proactively engage customers or personalize thresholds for the customer. Nor does the company have applications to interact on a tablet or smart phone. Idaho Power will begin exploring opportunities and system improvements to more actively engage its customers using the technologies preferred by customers.

Analyze Use of Technology and Process Changes to Improve Workforce Efficiency

Today Idaho Power distribution line design and construction processes utilize minimal technology in the field. Designers travel to meet the customer to evaluate the service location and confirm the customer's request, travel back to the office to design the job, and enter the design in the work management system. Similarly Customer Representatives providing energy-related services to customers utilize minimal field technology. Company representatives manage their work via paper orders and exchange information with customers via hard copy print outs.

Idaho Power will determine what technological and process improvements will improve efficiency and services provided by field employees in customer-facing positions.

For example: The company will evaluate if tablets that are wirelessly connected to Idaho Power systems would improve the efficiency of Distribution Designers as they meet with customers in the field. The devices could electronically send the information obtained to a centralized organization that designs the customer's request. The revised draft could then be sent back to the field Distribution Designer who meets with the customer and finalizes the arrangement, including digitized signatures via the tablet for documentation purposes. A similar example could include Customer Representatives with tablets meeting with customers and accessing customer information to provide proactive analysis on pricing, usage, and programs to satisfy customers' needs.

Other technologies and process improvement ideas would be evaluated in a similar manner. Using mobile computing devices could increase the efficiency of Idaho Power's field employees

and potentially provide customers with proactive energy use information.

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.

Electric Vehicle (EV) Charging Impacts Study

Idaho Power's Charging Impacts Project (CHIP) is an optional customer program intended to evaluate the impact of residential EV charging on Idaho Power's distribution system. An AMI meter in the customer's garage-based charging station circuit allows Idaho Power to analyze how these customers are charging their cars. These meters are not used for billing purposes but only for remote monitoring of charging patterns.

In operation for two years, the project has recorded valuable data. The natural behavior of EV owners is to plug in their vehicle as soon as they arrive home from work, allowing it to charge immediately. Because of this, CHIP is showing a significant increase in customer peak energy use as shown below in Figure 9. The energy used to charge the EV could potentially be shifted to off peak through time-based rate signals. In fact, one EV owner in the project who is also participating in Idaho Power's TOD pricing plan shifts his energy use to off peak quite successfully. All mass-produced EVs on the market allow the owner to easily program their vehicle to either begin or end charging at an owner-specified time.

Figure 9 shows the increase in one customer's household demand due to plugging in an EV in the early evening upon returning from work. This graph is a snapshot taken on a hot summer day in 2013.

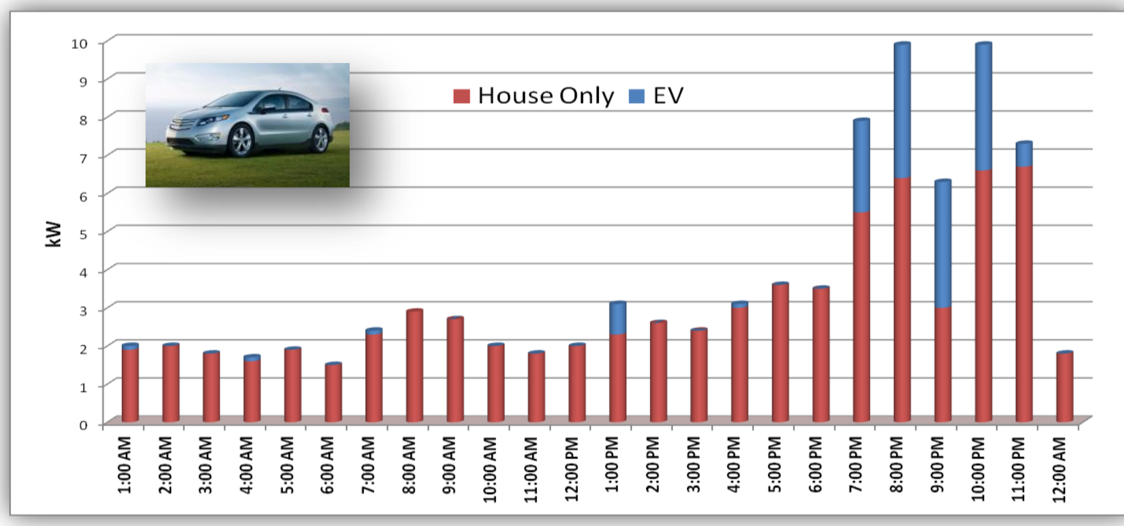


Figure 9. Demand Increase Due to EV on Summer Peak Day, Non-TOD Customer

The following figure shows how one customer is willing and able to respond to TOD price signals, both with his house and EV charging. Note, this graph should be viewed as an exceptional example of price response and not what might be normally expected.

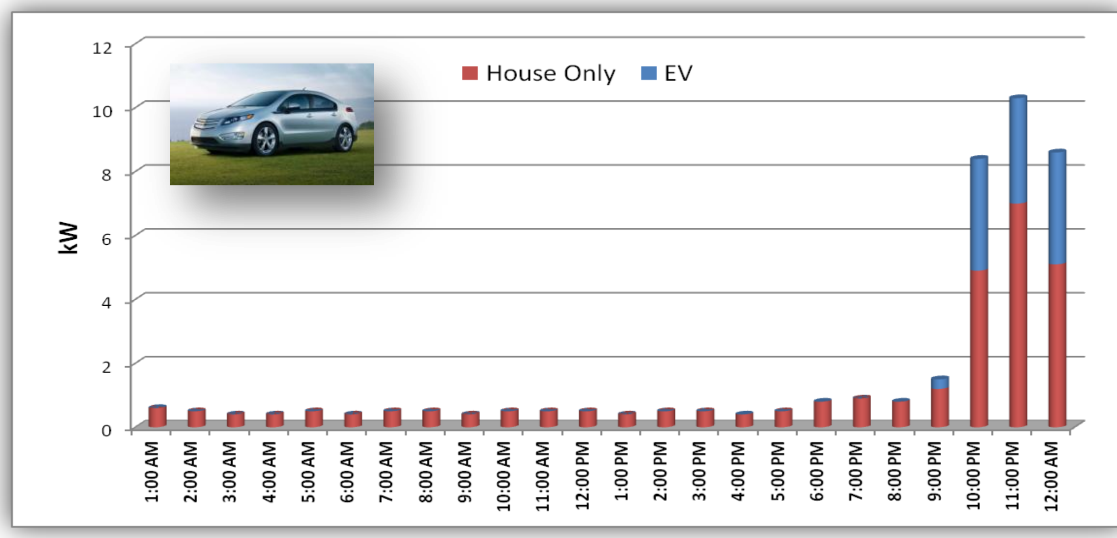


Figure 10. Demand Increase Due to EV on Summer Peak Day, TOD Customer

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 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 output (typical customer orientation), west for maximum output coincident with feeder peak demand, and horizontal for the global solar-intensity reference.

Solar intensity data was gathered at three locations in West Boise during the summer of 2013. Initial analysis of the data indicates that there is indeed a relationship between solar intensity and electrical load under some circumstances. It was not a surprise that a stronger correlation exists between ambient temperature and electrical load. The data also indicates that PV panel orientation can be aligned to more closely follow the peak demands on a summer afternoon; however, more study is needed to assess overall benefits as well as the detriments to this approach. Solar data continues to be gathered and is finding uses in impact and integration studies. It will be interesting to review the panel orientation data gathered during the winter and compare it to the analysis of the data gathered during the summer.

Demand Response as Operating Reserves Feasibility

In settlement agreements filed in both Idaho and Oregon (Idaho Case No. IPC-E-13-14 and Oregon Case No. UM 1653) and approved by the Idaho Public Utilities Commission (IPUC) and the OPUC in Order Nos. 32923 and 13-482, respectively, Idaho Power agreed to investigate the feasibility of using DR as operating reserves and to make a determination on the feasibility by the end of the third quarter of 2014.

The company filed a Demand Response as Operating Reserves Feasibility Report (DR Report) with the IPUC and OPUC on September 30, 2014, which is provided as Appendix I. The DR Report provides a background of the company's operating reserves requirements, and identifies that DR could only be used for the non-spinning portion of the company's Contingency Reserves Obligation (CRO). It describes each of the DR programs the company currently operates, discusses the applicability of using DR as CRO from a compliance perspective, and describes the implementation requirements for the company to use its DR programs as CRO. The DR Report then examines each of the DR programs and discusses whether or not each one has potential to be used as CRO. The DR Report concludes with the company's financial analysis and recommendation.

Based on its analysis, Idaho Power concluded the risks outweigh the benefits to utilize DR as CRO because: (1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and provide for program costs, (2) the risks for failure to meet NERC standards is far greater than the economic benefit that might be derived, (3) the period of testing that would be required to provide operational certainty of compliance with NERC and WECC requirements would require carrying substantially more than the reserves actually needed for contingency, at a cost to all customers, and (4) the number of CRO events would put too heavy of a strain on the DR participants, thus risking participation in the company's DR programs.

As described in the DR Report, the economic benefits, excluding payments to participants, of using DR as CRO are insignificant when compared to the capacity benefit the current DR programs provide. While having a dual-purposed program may be conceivable from a technical and compliance perspective, the company believes that it is not practical from an economic and DR program participant perspective. The company believes that the economic, DR program participation and other operational risks identified in the DR Report, are too great to proceed with a pilot at this time.

Electric Vehicles for Idaho Power Circulator Route

Idaho Power is purchasing two new battery-electric vehicles for employee use when travelling between company facilities in the Boise area. Funded as a Sustainability Program project, the EVs will promote employee use of public/alternative transportation to get to and from work then use a company EV when travel between facilities is required. Additionally, the EVs will help to demonstrate the viability of electric vehicles to the general public. As part of this project, Idaho Power is installing five charging stations at various facilities to augment the existing charging stations at the Boise Operations Center.

Solar-Powered Parking Lot Lighting

In August 2013, Idaho Power replaced existing high-pressure sodium lighting in an employee parking lot with high-efficiency LEDs. Solar panels mounted on each light pole feed energy back onto Idaho Power’s distribution system with the intent that the lights will consume net-zero energy on a yearly basis. Manufactured and installed by Boise-based Inovus, the PV panels produced as much energy as they consumed over the course of one year. Compared to the old high-pressure sodium units, the high-efficiency LEDs provide better light and bring substantial energy savings. Whereas the old lights consumed approximately 4,250 watts, the new system requires just 1,552 watts. The following figure shows a profile of energy used versus energy produced by the old and new lighting systems. This demonstrates potential new technology that can enable energy using devices to become energy producers.

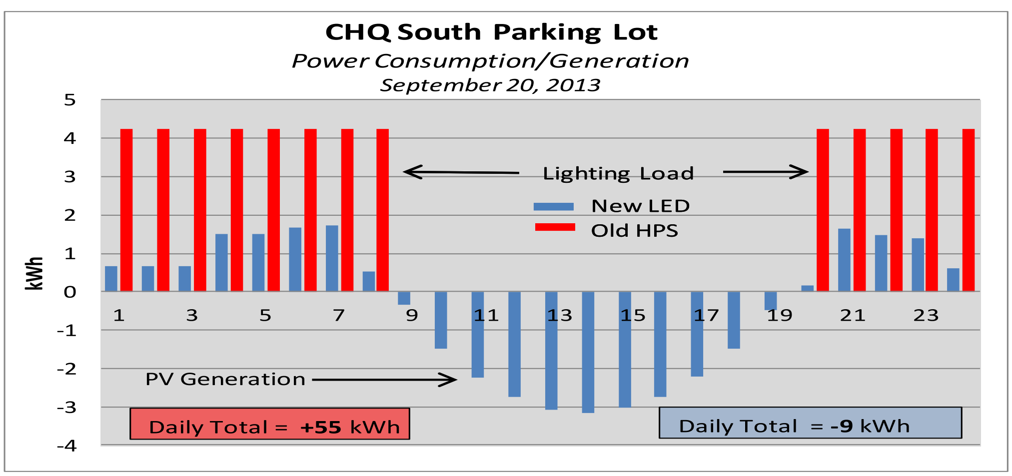


Figure 11. Solar-Powered Parking Lot Lighting Energy Consumption/Generation

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 EVs, distributed resources, and microgrids.

D. State of Key Technologies

Idaho Power's customers are increasing their use of electrical technologies while at the same time some customers are desiring to generate their own power. They also want to know more about the energy they use and have the ability to more finely control their usage. The enabling technologies that allow Idaho Power's customers to do this are present today and only limited by cost and maturity. As costs come down, the company can expect that the technologies will be used and may change our interactions and relationships from what they are today.

Key technologies Idaho Power is tracking include:

- Cost and technical maturity of PV generating resources
- Cost, technical maturity, and availability of EVs
- Communications technology relating to microgrid components
- Smart inverters used for PV integration
- Technical maturity of tablet computing devices and available applications for energy tracking
- Energy storage technologies

V. TARGETED EVALUATIONS

This section responds to the three stakeholder smart grid-related recommendations adopted in Commission Order No. 13-481, Docket UM 1675.

Recommendation No. 1:

> *(1) The Company should circulate a draft version of future smart grid reports at the same time they solicit comments and prior to filing at the Commission.*

Idaho Power complied with this recommendation as described in the Solicitation of Stakeholder Input section.

Recommendation No. 2:

> *(2) In the next Smart Grid report, IPC provide an update and timeline for current analysis of CVR. The Company should also detail the criteria it will use to gauge success and expandability of CVR efforts.*

This information is provided in the CVR project description in Section III of this report.

Recommendation No. 3:

> *(3) In the next Smart Grid Report, Idaho Power provide:*
>
> > *(a) An update on the current Time of Day (TOD) pilot;*

This information is found in the TVP section included in Section II.C of this report.

> > *(b) A time line and specific criteria for how the company will analyze critical peak pricing and seasonal pricing structure as potential options for IPC customers; and*

Critical peak pricing rate plans are often viewed as a form of DR which acquires capacity from customers. This capacity could be valuable when peaking resources are needed. Idaho Power currently has approximately 391 MW of available DR peaking resources in three existing programs: Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management. At this time these three programs are adequate to provide the dispatchable DR resource needed on the Idaho Power system. Idaho Power will monitor future additional DR peaking resources needs on the system and will evaluate whether a critical peak pricing plan should be implemented.

Idaho Power believes rate plans that incorporate TOD and/or seasonal pricing should reflect the costs to serve customers on the Idaho Power system and considers a TOD rate plan to be a seasonal rate plan. Idaho Power currently has in place seasonal pricing for all customers system-wide, except for residential customers in Oregon. During its last two Oregon general rate cases, UM 213 in 2009 and UM 233 in 2011, Idaho Power proposed seasonal pricing for Oregon residential customers.

> *(c) Criteria for how the TOD pilot will be evaluated and what participant behavior modifications and revenue impact outcomes would lead to decisions to expand the pilot or not.*

The primary goal of the TOD 2014 pricing study is to determine if participants changed their electric usage behavior in response to hourly changes in prices and to evaluate any revenue impact. The study results indicted:

- For the study group as a whole, the data analyzed showed both a reduction in energy use from peak time periods and an increase in energy use during off-peak pricing period by the analyzed participants of the pricing plan versus a carefully matched control group.
  - This finding indicates that the TOD pricing plan may impact customer behavior in a way that causes them to shift some of their usage to off-peak times.
- The TOD pricing plan structure was designed to more accurately reflect cost-of-service pricing as compared to the Standard rate pricing.
  - Therefore, the TOD rate plan offers a fair and appropriate rate plan.
- The study estimates that there is a reduction in revenue of $119,000 when actual TOD energy billings are compared with Standard plan shadow energy bill calculation for all TOD pricing plan participants during the 12 months of the study, September 2012 through August 2013.
  - If the TOD rate plan is optional, the company may be unable to collect its allowed revenue requirement as customers migrate to the TOD rate.
- The study findings indicate an overall response rate to the Idaho TOD pilot solicitation of 1.3 percent.
  - These study findings indicate that if the company were to expand the TOD offering to the remainder of the residential customer population system-wide in the exact same manner as in the Idaho TOD pilot, that approximately 4,000 additional participants would likely volunteer to sign up.

Due to these findings, Idaho Power is considering offering an optional residential TOD rate plan to its Oregon service area customers. Before implementing this wider TOD offering, considerations such as timing issues and whether there may be system barriers or implementation issues (i.e., billing, metering, information technologies issues, etc.) must be resolved before offering the plan to more customers. Commission approval will also be required to implement a TOD rate plan.

VI. Related Activities

This section discusses activities that relate to smart grid operations.

A. Cyber and Physical Security

All smart grid-related projects or plans conform to Idaho Power's Information Security Standards which are in place to secure its cyber assets. Idaho Power's aim is to strengthen its long-standing tradition of electric reliability while fostering a culture of compliance and satisfying a broad set of reliability standards.

Smart grid projects also conform to the requirements of Idaho Power's Physical Security Program which prevents unauthorized access to personnel, equipment, material, and documents while safeguarding against espionage, sabotage, acts of terrorism, damage, and theft. Physical security is an integral part of all critical infrastructure protection, safety, fire, and crime-prevention programs.

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 and supported by periodic required training. 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.

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

Idaho Power provides 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 it. 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, seven days a week.

Idaho Power CSRs have the ability to answer residential and small commercial customers' questions about their detailed energy usage. This specific data is available for TVP rate structure (residential), while using features in the Customer Service Representative (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.

Customer Outreach and Education Events

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 154 outreach activities, including events, presentations, trainings, and other outreach activities documented in 2013 in the Outreach Tracking System. In addition to these activities, Idaho Power field staff throughout Idaho Power's service area delivered 174 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2013, Idaho Power's Community Education team provided 80 presentations on *The Power to Make a Difference* to 2,291 people. The community education representatives and other staff also completed 53 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 1,235 seniors in the company's service area.

At these events, Idaho Power employees cover a wide range of information, answer customer questions, and assist customers in registering for the company on-line self-help services. The company also promotes www.idahopower.com, using myAccount to help customers learn more about using energy, tips and ideas to save energy, energy efficiency program information, smart meter information, 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, *Connection* articles, customer letters, doorknockers, postcards, brochures, web content at www.idahopower.com, hold messaging on the company's 1-800-488-6151 phone line, social media, public events, and customer visits.

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 on myAccount.

VII. CONCLUSION

Idaho Power has developed a vision that anticipates what the future energy delivery system will look like and how it will meet customer expectations. Along with the vision, a strategy has been developed to test and deploy the technologies needed to facilitate the transition to a smart grid future. Much has been done in the past few years and much remains to be done.

Building upon the successful deployment of the automated metering infrastructure, the task now becomes using AMI as a communications and data backbone to enable more proactive customer interaction. Idaho Power will also deploy technologies that can control devices both on the distribution system and the transmission system to provide for a high level of power quality, reliability, and robustness. The system will also be able to accommodate renewable generation and integrate it into the power system.

The smart grid will provide Idaho Power's customers with an efficient, reliable, and safe power system that fits with customer expectations of a more interactive experience.

Appendices

IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix A

Status of Smart Grid Initiatives – 2013 and 2014

STATUS OF SMART GRID INITIATIVES - 2013 and 2014

INITIATIVE	STATUS	START DATE	COMPLETION	REPORT/ STUDY LOCATION
II. STATUS OF CURRENT SMART GRID INVESTMENTS				
A. Transmission Network and Operations Enhancements				
Transmission Situational Awareness Project	In Use/Under Development			(1)
Transmission Situational Awareness Peak Reliability Hosted Advanced Application	Complete/In Use	2011	2014	
Available Transfer Capacity Calculation Tool	In Use/Under Development	2011	2014	(1)
Dynamic Line Rating Pilot	Pilot/Under Development	2010	2014	(1) and (2)
B. Substation and Distribution Network and Operations Enhancements				
Transmission Transformer Geomagnetic Disturbance Monitoring	In Use/Under Development	2012	2015	(1)
Conservation Voltage Reduction Enhancements	In Use/Under Development	2006	2016	
C. Customer Information and Demand-Side Management Enhancements				
Advanced Metering Infrastructure	In Use/Under Development			(1)
Customer Information System Replacement	Complete/In Use			(3)
Time Variant Pricing	Pilot	2012	2014	(1) and (2)
Energy Use Advising Tool (my Account)	Complete/In Use			(1)
Direct Load Control				
Irrigation Peak Rewards	Ongoing			
FlexPeak Management	Ongoing			(1)
A/C Cool Credit	Ongoing			(1)
Irrigation Load Control Pilot	Ongoing			
D. Distributed Resource and Renewable Resource Enhancements				
Renewable Resources: Renewable Integration Tool	In Use/Under Development			(1)
Photovoltaic and Feeder Peak Demand Alignment Pilot	Pilot/Under Development	2014	2015	
Renewable and Other Energy Contracts	Ongoing			
Net Metering	Ongoing			
E. General Business Enhancements				
Advanced Metering Infrastructure Communications	Complete/In Use			(3)
Idaho Power Enterprise Data Warehouse	Under Development	2010	TBD	

INITIATIVE	STATUS	START DATE	COMPLETION	REPORT/ STUDY LOCATION
III. FUTURE SMART GRID INVESTMENTS				
A. Transmission Network and Operations Enhancements				
Transmission Situational Awareness Oscillation Monitoring Pilot	Pilot/Under Development	2012	2015	(1) and (2)
Transmission Situational Awareness Voltage Stability Monitoring Pilot	Pilot/Under Development	2012	2015	
Transmission Situational Awareness Grid Operator's Monitoring and Control Assistant	Under Development	2014	TBD	(2)
B. Substation and Distribution Network and Operations Enhancements				
Substation Fiber-Based Protection and Control Pilot	Pilot/Under Development	2013	2015	
Automated Volt/VAr Management System Pilot	Pilot/Under Development	2015	2017	
Conservation Voltage Reduction Program Enhancement Project	Pilot/Under Development	2014	2016	(2)
ENGO Solid State Reactive Power Compensation Device Pilot	Pilot/Under Development	2014	2015	(2)
Distribution System Communications Strategy	Under Evaluation	2014	TBD	
Ability of the AMI System to Control Line Devices	Under Evaluation	2015	TBD	
Replace the Existing Outage Management System	Pilot/Under Development	2014	2016	
Implementation of Automated Connect/Disconnect Capability at Selected Locations Through the AMI System	Pilot/Under Development	2014	2015	
Implement Additional AMI Outage Scoping and Restoration Confirmation Functionality	Pilot/Under Development	2013	2016	
C. Customer Information and Demand-Side Management Enhancements				
Customer Relationship Management	Planned	Tentative Q2-2015	Q4-2015	(1)
Integrated Demand Response Resource Control	Under Evaluation	TBD	TBD	
D. Distributed Resource and Renewable Resource Enhancements				
Renewable Integration Tool: Potential Future Projects	Under Development	TBD	TBD	
E. General Business Enhancements				
Upgrade the Mobile Workforce Management System	Planned	2015	2015	
Upgrade the Meter Data Management System	Under Evaluation	TBD	TBD	

INITIATIVE	STATUS	START DATE	COMPLETION	REPORT/ STUDY LOCATION
V. SMART GRID OPPORTUNITIES AND CONSTRAINTS				
A. Transmission, Substation, Operations, and Customer Information Enhancements				
Hourly Customer Usage Data	Ongoing			
DOE ARRA Smart Grid Grant Projects				
Home Area Network	Under Evaluation	TBD	TBD	
Personalized Customer Interaction	Under Evaluation	TBD	TBD	
Analyze Use of Technology and Process Changes to Improve Workforce Efficiency	Under Evaluation	TBD	TBD	
B. Evaluations and Assessments of Smart Grid Technologies				
Electric Vehicle Charging Impacts Study	Pilot/Under Development	2012	2016	
Photovoltaic and Feeder Peak Demand Alignment Pilot	Pilot/Under Development	2012	2014	
Demand Response as Operating Reserves Feasibility		2014	2014	(2)
Electric Vehicles for Idaho Power Circulator Route	Pilot/Under Development	2014	2016	
Solar-Powered Parking Lot Lighting	Complete/In Use	2013	2014	
C. Smart Grid Pilots and Programs				

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 this designation projects have already started and have no completion date because they are ongoing.
Under Development – for projects that either are not complete at this time or are continuing to be improved
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
TBD – to be determined

(1) – See OPUC Case No. UM 1675 for 2013 Idaho Power Smart Grid Report and appendices.
(2) – 2014 Smart Grid Report Appendix.
(3) – Content only in 2013 Smart Grid Report.

Notes:

- Red print means 2014 projects. Projects reported initially in the 2013 Smart Grid Report are in black print.
- Dates in this document may have been adjusted from 2013 Smart Grid Report due to project timeline changes.
- Some projects have been relocated in this table from 2013 Smart Grid Report in order to place in more correct categories.

IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix B

Newspaper Ad and Email Solicitation

Nemnich, Darlene

From: Towell, Kimberly
Sent: Friday, August 01, 2014 1:14 PM
To: 'oregondockets@pacificorp.com'; Bearry, Christa; 'kacia.brockman@state.or.us'; Bryant, Jan; 'john@grid-net.com'; 'gordon@oregoncub.org'; 'renee.m.france@doj.state.or.us'; 'rfrisbee@si-two.com'; 'maury.galbraith@state.or.us'; 'richard.george@pgn.com'; 'wendy@nwenergy.org'; 'royhemmingway@aol.com'; 'bob@oregoncub.org'; 'pkeisling@gmail.com'; 'jess.kincaid@state.or.us'; 'keith@caporegon.org'; 'adam@mcd-law.com'; 'douglas.marx@pacificorp.com'; 'catriona@oregoncub.org'; 'wendy@mcd-law.com'; 'michelle.mishoe@pacificorp.com'; Nordstrom, Lisa; 'elaine.prause@energytrust.org'; 'dockets@mcd-law.com'; 'pge.opuc.filings@pgn.com'; 'john.volkman@energytrust.org'; 'michael.weirich@state.or.us'; 'woods@sustainableattorney.com'; Youngblood, Mike; 'dockets@oregoncub.org'; Dockets; 'greg@richardsonadams.com'; 'stephanie.andrus@state.or.us'; 'erik.colville@state.or.us'; 'bryce.dalley@pacificorp.com'; 'mjd@dvclaw.com'; 'megan@renewablenw.org'; 'jdj@racinelaw.net'; 'judy.johnson@state.or.us'; 'elo@racinelaw.net'; 'dreading@mindspring.com'; 'peter@richardsonadams.com'; 'irion@sanger-law.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@renewablenw.org'; Brittany Andrus; 'phil.carver@state.or.us'; 'esteb44@centurylink.net'; 'patrick.hager@pgn.com'; 'brian.kuehne@pgn.com'; 'jravenesanmarcos@yahoo.com'; 'nelson@thnelson.com'; 'denise.saunders@pgn.com'; 'aster.adams@state.or.us'; Nemnich, Darlene; 'vijay.a.satyal@state.or.us'
Cc: Nemnich, Darlene
Subject: Idaho Power 2014 Oregon Smart Grid Report - Comments solicited
Attachments: Draft2014OregonSmartGridReport.pdf; Smart Grid Newspaper Ad.pdf

Parties to Docket Nos. UM 1460, UE 233, LC 58, and UM 1675:

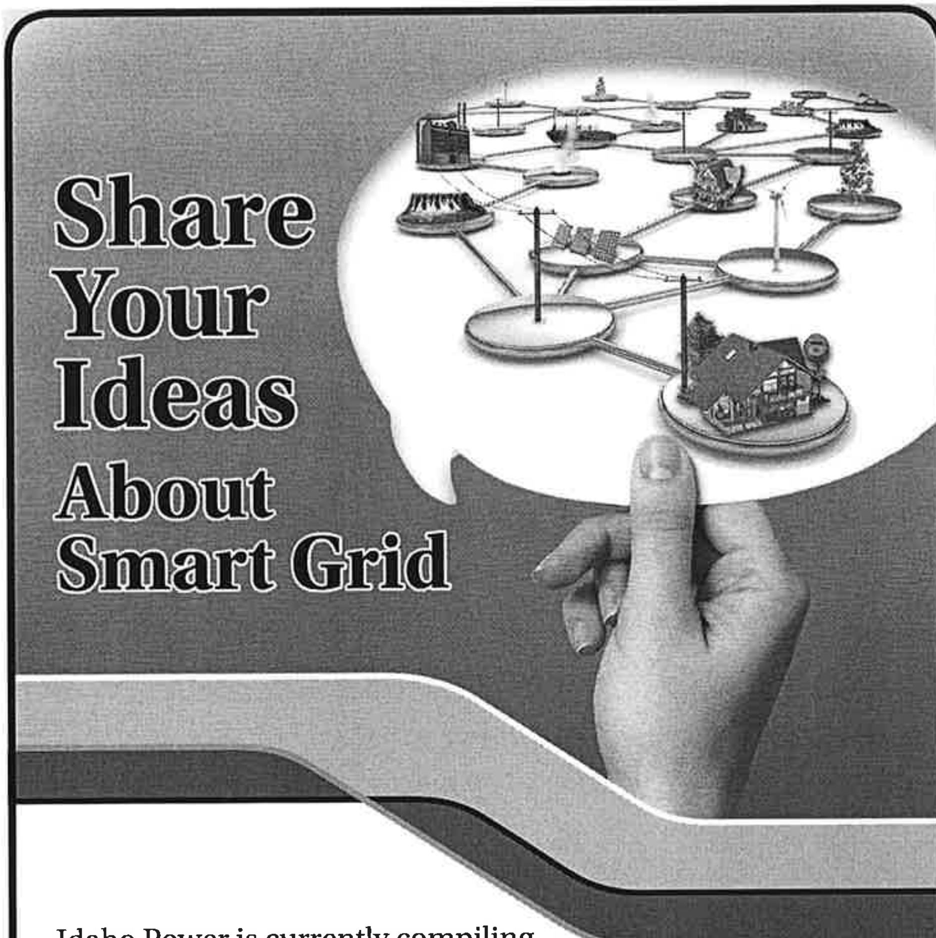
Idaho Power Company will be submitting its second annual Smart Grid Report to the Public Utility Commission of Oregon on October 1, 2014. As part of the annual report, Idaho Power is seeking public input and contributions from August 1 through August 31, 2014, on the attached Draft Smart Grid Report. 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 smart grid reports and projects, go to www.idahopower.com/smartgrid.

Thank you,

Darlene Nemnich | Senior Regulatory Affairs Analyst | Idaho Power Company
1221 West Idaho Street, Boise, ID 83702 | ☎208.388.2505 | dnemnich@idahopower.com



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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2014 SMART GRID REPORT

Appendix C

"Dynamic Line Rating: Concept, Case Study, and Regulatory Review" by INL

Dynamic Line Rating: Concept, Case Study, and Regulatory Review

Michael R. West, Jake P. Gentle, Warren L. Parsons, Phil Anderson

Abstract— ***Overhead lines are given a conservative ampacity rating based on worst case environmental conditions. Dynamic Line Rating (DLR) is a smart grid technology that allows the current rating of electrical conductors to be monitored in real time, based on regional climatology. By dynamically rating transmission systems, current levels can be allowed to fluctuate above the static rating in a safe, effective manner. This paper provides a report of a pioneering scheme in the United States of America in which DLR has been applied. Secondly, regional weather conditions are discussed. In doing so, we arrive at novel insights which will inform and improve future DLR projects. Third, we review policies and barriers that may hinder or benefit from the imminent adoption of dynamic line rating systems, and provide suggestions for regulatory bodies about possible improvements in policy to encourage adoption of this technology.***

***Index Terms*— Power transmission, Fluid Dynamics, Power system planning, Energy Policy**

I. INTRODUCTION

Traditionally, conductors in a power system are given a static temperature rating based on conservative, regional climatology. This rating is considered to be the critical limit of the line and damage may be incurred if exceeded for a long duration of time. Thermal characteristics are one of the main contributing factors on ampacity limitations. Maximum ampacity ratings are determined based on IEEE Std. 738TM-2012 [1-3]. However, current flow through transmission lines varies based on loads connected to distribution systems. Fig. 1 shows these variations with a typical diurnal load flow comparison between California and Idaho. Note that California's load peaks during the hotter summer months, while Idaho's load peaks during the long, cold winter. Because temperature ratings are conservative, conductors have unused headroom and are not optimized. By dynamically rating transmission lines, owners may avoid costly upgrades, increase yield of distributed generation (DG), and support networks during outages.

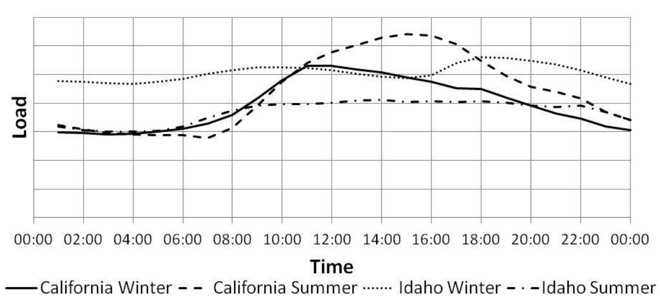


Figure 1. Example of Diurnal Load Flow

This paper provides a climatological assessment of the research test bed, describes INL's methodology of DLR using computational fluid dynamics (CFD) simulation and an INL custom-built, Java-based iterative solver, and enlightens political implications for regulatory bodies of Dynamic Line Rating (DLR), also known as Dynamic Thermal Ratings, Real-Time Thermal Rating, Real Time Rating, and Concurrent Cooling. The work documented focuses on overhead lines (OHLs), the component that stands to benefit the most from the adoption of DLR [4]. Fig. 2 shows the energy balance in an OHL between environmental conditions and heating by the Joule Effect.

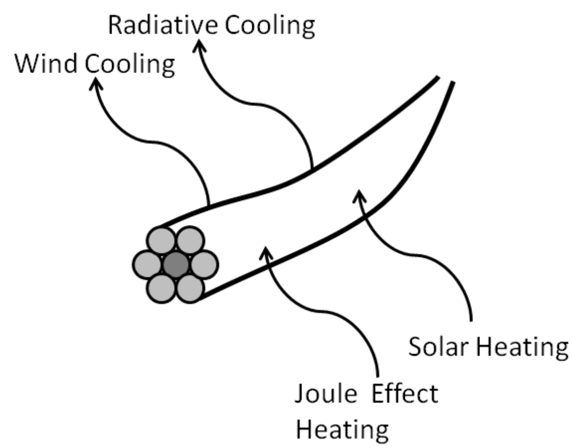


Figure 2. Diagram of the heat balance within a conductor

This energy balance is described mathematically by Michiorri, Taylor, and Jupe in their 2010 article [4]:

$$I^2R(T_C) + q_S = q_C + q_r \qquad (1)$$

where q_s, q_c, and q_r is the heating through solar radiation, cooling through convection, and cooling through radiation, respectively. T_C is the core temperature of the conductor, $I^2R(T_C)$ represents internal heating from the Joule Effect due to line current. Equation (1) represents a steady state case, where the line has reached thermal equilibrium.

II. Case Study

A. Overview

A trial site in the U.S. is located in a small corridor along the Snake River Plain in Idaho. A map of the site is shown in Fig. 3. Varied terrain, seasonal trends in weather, and available instrumentation make this region prime for DLR research. More than 430MW of wind power generation is also available in this region, directly correlating with dynamic line rating as more wind generates more power and effectively cools transmission lines at the same time. Fig. 4 shows a local weather station installed on a wooden transmission line structure. This is a transmission line that carries local wind generation to a nearby substation.

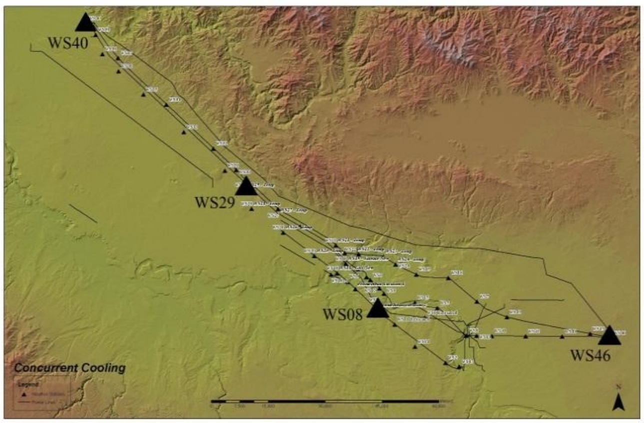


Figure 3. Map of Trial Site located in the Snake River Plane of Idaho

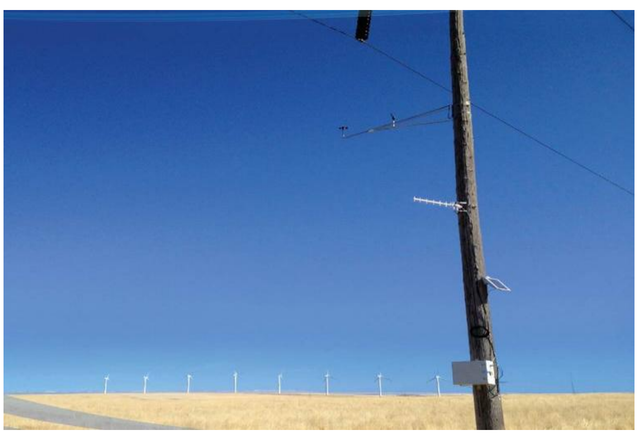


Figure 4. Image of weather station installed near Wind Park

Presently, the dynamic ratings of two 138kV lines and two 230kV lines are being studied with 20 weather stations instated at strategic locations on tower structures along the lines. All weather stations are spaced between 1 and 5 miles apart. It is important to note that this is a straight line distance between all weather stations. Each conductor may have instruments installed approximately 10 miles apart, but because all conductors are in the same corridor, multiple weather stations in the same location of line are not necessary.

Once data is collected, the information is processed in pseudo-real time. Fig. 5 shows an overview of data flow in order to effectively relay appropriate information to operators and initiate current flow adjustments. Data shown in this paper is collected from weather station 40, 29, 8, and 46.

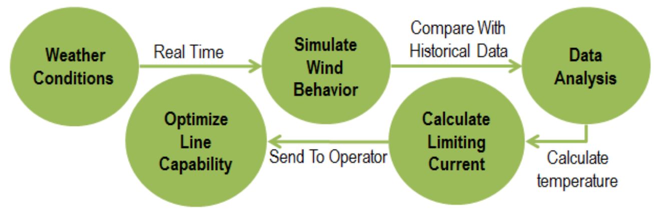


Figure 5. Data Flow Representation from Real-Time Weather Assessment to Operator

B. Weather Assessment

Understanding regional weather behaviors is critical for dynamically rating transmission lines accurately. INL's structure mounted weather stations, installed at mid-span height (~10m), collect 4 critical parameters: wind speed, wind direction, ambient air temperature, and solar irradiance. Each station takes a sample measurement every 15 seconds, and logs the average and maximum of these samples every 3 minutes.

Due to the stochastic behaviors of regional climatology, weather conditions cannot be exactly predicted. However, historical data shows local trends in both short term and long term periods. Fig. 6 shows average seasonal conditions with approximately 72°F during the summer months and 32°F in the winter.

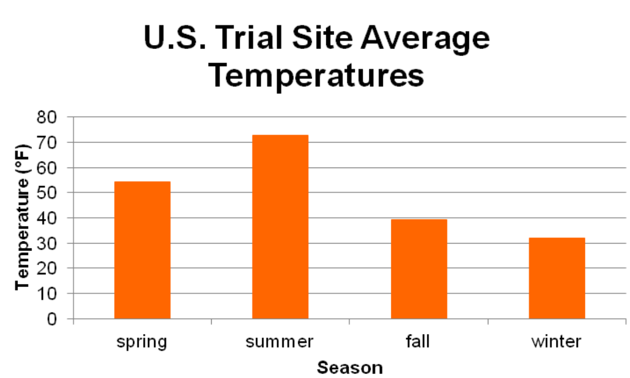


Figure 6. Seasonal variations in temperature provide broad range of research capabilities

This work is supported by the U.S. Department of Energy Wind Power Technology Office contract with Idaho National Laboratory. The authors would also like to acknowledge the contributions and support of Idaho Power.

Jake P. Gentle, Warren L. Parsons, and Michael R. West are with the Idaho National Laboratory, USA (Jake.Gentle@inl.gov)

Phil Anderson is with Idaho Power Company, USA.

While ambient temperatures are an important factor in DLR, wind stands to have the greatest effect on concurrent cooling [1]. Fig. 7 shows a combined snapshot of wind speed data taken at several locations within the trial site. The data represents average wind speeds across a three month period of sampling. Important information can be gleaned such as the lower average wind speeds in the 3rd subplot. This suggests that this region may possibly house the majority of limiting dynamic ratings simply due to the lower wind speeds.

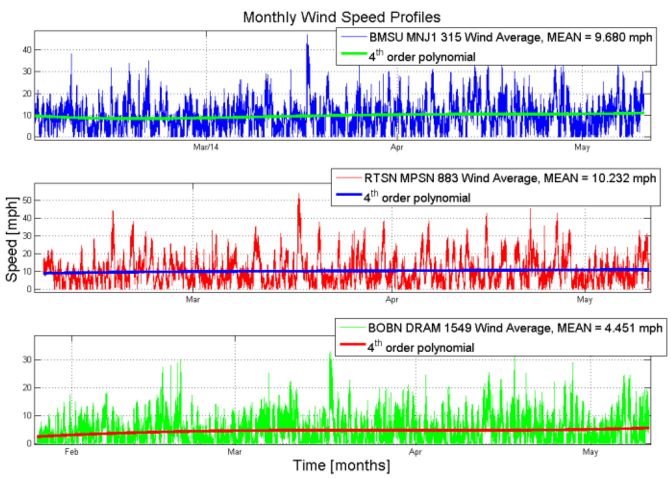


Figure 7. 3 month snapshot of wind speeds collected at several points of interest

Fig. 8 shows a snapshot in time of wind flows across the entire region, showing how a spike in wind speed at all 3 locations occurs with a time delay between each one. Using this information, and verifying with wind direction measurements, regional wind flow patterns can be identified. A time delay between rapid increases in wind can be seen between the hours of 3:00am and 6:00am. Generally lower wind speeds at WS40 suggests that the limiting region of concurrent cooling may reside in this region most of the time. Wind direction must be considered as well, and can have as much of an impact on cooling overhead lines as the wind speed itself. Maximum surface area contact between wind and overhead lines provides most convective heat loss.

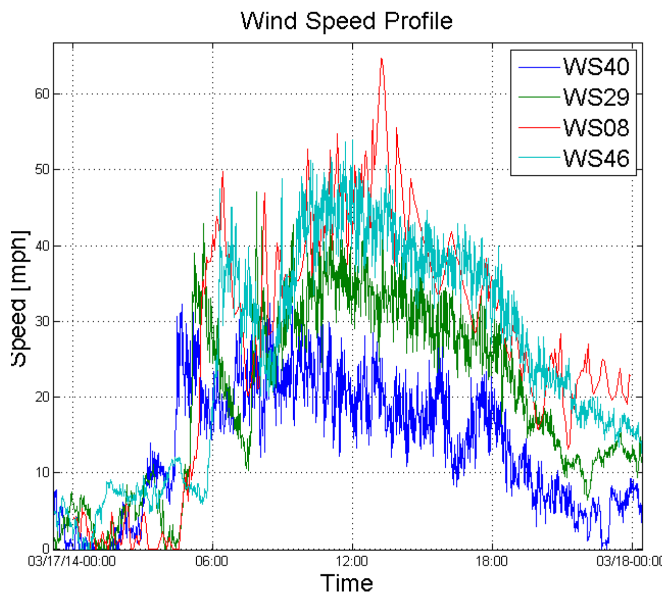


Figure 8. March 17, 2014 wind speed profile demonstrating flow patterns from east to west

Due to the variations in wind speeds, limiting regions or “hot spots” may appear at specific locations along conductors for the majority of the time as a result of lower wind speeds. By collecting a database of historical weather conditions, trends in weather patterns at each location can be easily identified and possibly create a static location that can create a critical region of interest for thermal ratings.

C. Computational Fluid Dynamics Modeling

WindSim, a computational fluid dynamics (CFD) program originally developed for wind farm annual energy production, approximates environmental conditions incident to transmission lines between weather stations. Using classical 3D Reynolds-Averaged Navier-Stokes (RANS) equations, the INL simulates wind velocity along the length of the line at specific points 500-1000m apart. Using historical data obtained from the weather stations, the model may be refined to account for seasonal trends in climatology patterns.

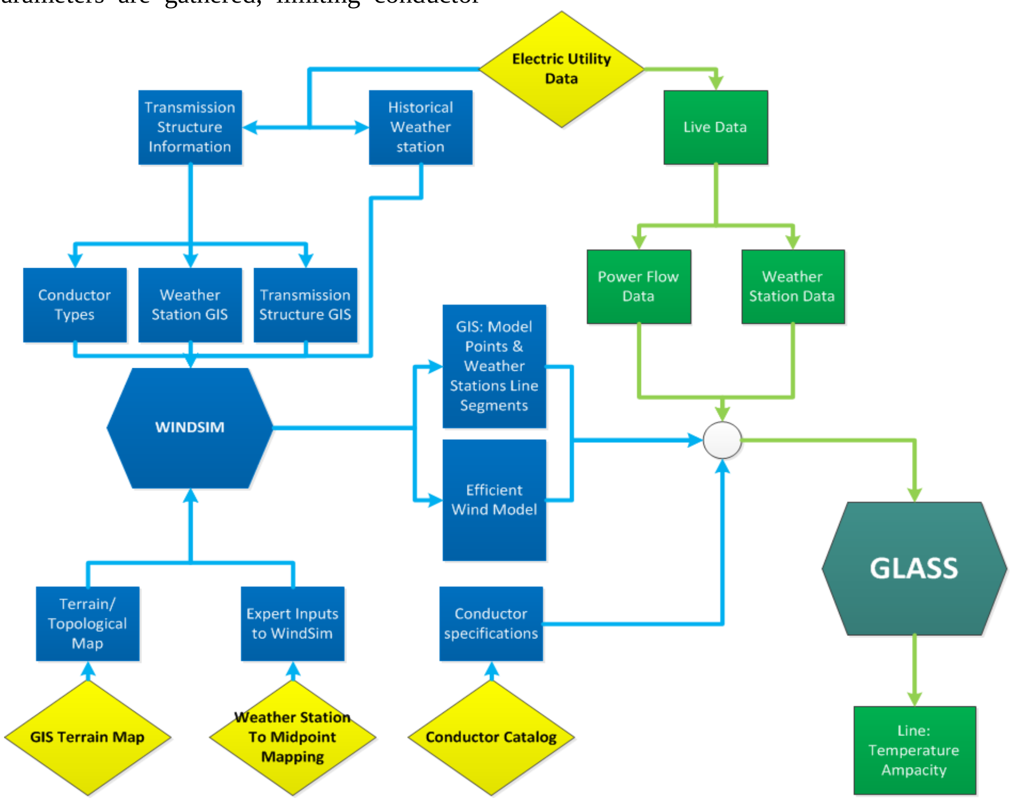
In addition to using historical weather data, INL uses RANS nonlinear transport equations to include complex terrain [5]. Digital terrain models with length scaling sufficiently describe the geography within the applied mesh. RANS mass and momentum equations can then be used to predict wind velocities at points of interest along the conductor.

Terrain roughness such as topographical effects, trees, shrubs, and buildings have a strong influence on wind speed at the zone near the ground and disrupt laminar flows. This roughness is also included in the model to account for terrain effects that are smaller than the grid. Since the terrain is modeled as a surface roughness rather than fully realized 3D objects, effects such as sheltering from vegetation can only be approximately represented.

As with all computational programs, limitations do exist for simulating wind conditions over larger geographic areas. This is an area currently being improved upon in order to mesh smaller pieces of terrain together into one large simulation.

D. General Line Ampacity State Solver (GLASS)

It is anticipated that line ratings will be determined for 15 minute intervals. Once wind speed and other environmental parameters are gathered, limiting conductor temperatures can be identified. This analysis is done using General Line Ampacity State Solver (GLASS); GLASS is an INL custom-built, Java-based program that combines the real time model point simulations from WindSim, power flow data, and conductor information in order to accurately assess conductor temperatures and ampacity. Flow Diagram 1 shows a diagram of data tracked into and out of GLASS. Data is displayed in a simple graphical user interface. Equations used to determine the conductor temperature as a function of current and environmental condition have been used for some time, and are documented in the IEEE standard 738 [1].



Flow Diagram 1. Flow Diagram for GLASS: Blue - static configuration data; Green - dynamic data

The heat balance (1), as introduced in Section I, is used to calculate the steady state current carrying capacity of a conductor.

Solving (1) for the current I yields:

$$I = \sqrt{\frac{q_c + q_r - q_s}{R(T_c)}} \quad (1)$$

We determine q_r (radiated heat loss rate per unit length – W/m), q_c (convective heat loss rate per unit length – W/m), and q_s (heat gain from sun) using

$$q_r = 0.0138D\varepsilon\left[\left(\frac{T_c + 273}{100}\right)^4 - \left(\frac{T_a + 273}{100}\right)^4\right] \quad (2)$$

where ε is the emissivity, D is the conductor diameter, T_c is the conductor temperature, and T_a is the ambient air temperature, and

$$q_s = \alpha Q_{se} \sin(\theta) A' \quad (3)$$

where α is the solar absorptivity, Q_{se} is the total solar and sky radiated heat flux rate with elevation correction, θ is the effective angle of incidence of the sun's rays, and A' is the projected area of conductor per unit length.

The convection heat loss has two equations: the value q_{c1} for low air speed (<3 mph) and q_{c2} for higher air speed:

$$q_{c1} = \left\{1.01 + 0.0372\left(\frac{DV_w\rho_f}{\mu_f}\right)^{0.52}\right\}k_f K_{angle}(T_c - T_a) \quad (4)$$

$$q_{c2} = \left\{0.0119\left(\frac{DV_w\rho_f}{\mu_f}\right)^{0.6}\right\}k_f K_{angle}(T_c - T_a) \quad (5)$$

where V_w is the speed of the air stream at conductor, K_{angle} is the wind direction factor, and the parameters ρ_f (air density), μ_f (dynamic viscosity), k_f (thermal conductivity), must be calculated for the current ambient temperature. K_{angle} can be found using equation (6).

$$K_{angle} = 1.194 - \cos(\phi) + 0.194\cos(2\phi) + 0.368\sin(2\phi) \quad (6)$$

where ϕ is the angle between wind direction and the conductor axis [1].

Verification of GLASS is being conducted using software written to produce test log data files. This program is configurable to any number of transmission lines and produces random readings within specified boundary conditions and rigorously tests GLASS developments. Doing so allows for rapid debugging and troubleshooting errors that may exist internal to GLASS.

E. Results and Discussion

Throughout a 3 month testing period, available ampacity improvements ranged between 32% and 75% above static, calculated using an industry standard Penguin 6/1 ACSR (aluminum conductor steel reinforced) and actual weather data collected from WS08. This conductor was chosen simply as a representation for use in this analysis. Fig. 9 shows a comparison between the static rating (red) and the dynamic rating (dark blue). A 4th order polynomial is used to show trend line in the dynamic rating. As a time constant is involved for reaching a state of thermal equilibrium, a 30 minute moving average (light blue) is included. Future research on evaluating this time constant will be conducted in order to improve the accuracy of this methodology.

It is important to note that although the dynamic rating is generally higher than the static rating, there is some risk of it dropping below the static rating as a result of high loading and extreme weather conditions that may exceed worst case scenario static expectations. However, these low dynamic ratings are short in duration and are already considered when strictly using static ratings.

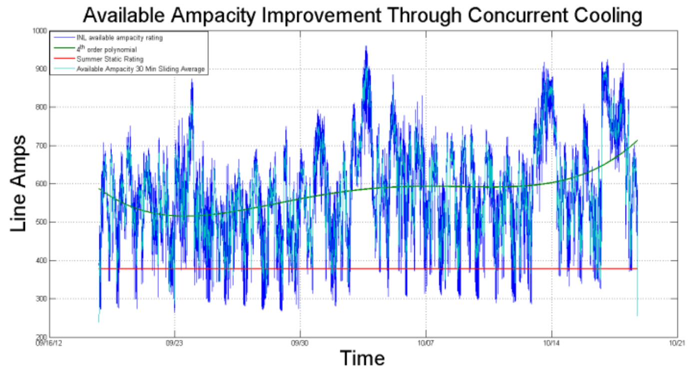


Figure 9. Dynamic ampacity rating (dark blue) and 30 minute sliding average (light blue) compared with static rating (red)

Fig. 10 is an alternate representation of the data shown in Fig. 9, and shows the percentage of time that a specific amount of ampacity is above the static rating. At the intersecting point of the static rating and additional available capacity, risk of dropping below the static rating can be identified; this occurred less than 7% of the time. In other words, dynamic line rating improved the capacity of the transmission line 93% of the time during this particular snapshot. This number will vary across the system, and will also vary across the seasons. Utilizing DLR enables a system to know exactly what the true line capacity is in real-time.

Using DLR, additional installation of generation resources is possible without upgrading transmission lines. Concurrent cooling and wind generation are directly proportional as more wind increases production and cools conductors.

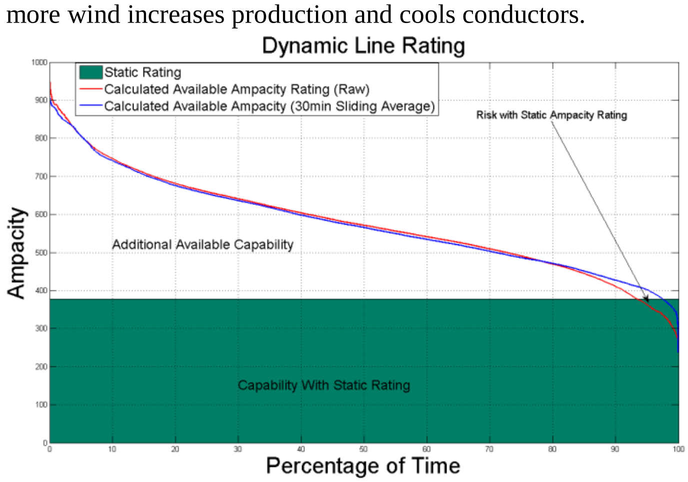


Figure 10. Risk of Dynamic Rating Dropping Below Static Rating

III. Policy and Regulation Associated with DLR

A. Overview

Transmission capabilities can help or hinder renewable energy development. Increasing integration of renewable generation sources, like wind and solar, requires new technologies, such as DLR, to maintain reliability, accurately define necessary limitations, and assist growth of these beneficial energy sources. The cost of this technology is reducing, making it a likely contender to provide the transmission improvements needed[6]. Some regulatory challenges remain that may prevent the timely deployment of DLR technology. A non-comprehensive list of these regulations include the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007, FERC Order 2000, and other standards initiated by FERC for Facilities Design, Connections, and Maintenance (FAC)

B. Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPACT) expanded FERC's authority to impose mandatory reliability standards on the bulk transmission system. This was in response to transmission infrastructure impediments across state boundaries [7]. Under certain conditions, the EPACT allows FERC to be petitioned by developers to exercise its imminent domain authority in order to construct new transmission.

EPACT of 2005 also creates opportunity for DLR through a loan guarantee program both for advanced generation technologies and technologies that *maximize efficient use of transmission infrastructure*. In addition FERC was granted the oversight of incentive rates for new transmission facilities that seek to enhance reliability and efficiency of wholesale power markets. Order 679 outlines the criteria for qualifying for the incentive rates[7]. In November 2012 FERC made a Policy Statement that may increase access to pricing incentives for transmission improvements such as DLR. Paragraph 21 removed barriers by allowing the incentives first set forth in the EPACT of 2005 to be applied more broadly. This means better grid management or new technology introduced to the grid would be subject to a higher rate of return [8].

Restrictions on transmission development could also be a boon for DLR. Those developers seeking to qualify for the lower incentive rates outlined in Paragraph 21 would first need to show that they "considered alternative means of achieving the improvement.[8]" As costs for DLR technology fall it can be used more aggressively as an alternative.

C. Energy Independence and Security Act of 2007

The Energy Independence and Security Act (EISA) set forth standards by which utilities could begin modernizing the transmission system. These standards included incentives to spur the development of "smart grid" technology. It also directed DOE to increase research and development (R&D) efforts relating to transmission and distribution[9]. The research outlined above to increase reliability of DLR, is the result of R&D supported by the DOE. It is important that FERC along with the DOE, leverage investor capital and interest to ensure this beneficial research is applied.

D. FERC Order 2000

FERC order 2000 requests that transmission owning utilities transfer control to regional transmission organization (RTO). The RTO would also be granted operational authority for all of those transmission facilities under its control, "including security aspects to ensure real-time operating reliability.[7]" The order failed to include provisions to incorporate nonjurisdictional utilities. Since they compose a significant percentage (30%) of transmission in the U.S. their lack of incentive to cooperate has led to the failure to form an integrated network of RTOs [7]. The establishment of RTOs could provide a pathway to better implementation of DLR.

E. Description of NERC Standards for Facilities Design, Connections, and Maintenance (FAC)

On January 1 of 2013 changes came into effect for FAC-008 and FAC-009. The update, FAC-008-03, applies to transmission and generation owners. It requires all Transmission Owners (TO) to provide "a documented methodology for determining Facility Ratings of its solely and jointly owned Facilities. [12]" This may include ratings based on data from the manufacturer of a conductor, performance restrictions or industry standards, such as IEEE.

The revised standard also aggregates the communications ratings previously found in FAC-009. This is the major improvement that may allow DLR to gain a place in transmission planning. The communication rating adds the requirement for TOs to provide detailed ratings information upon request by a Planning or Reliability Coordinator.
This system of checks and balances will allow for improved management. As DLR technology is proven more reliable and adoption occurs, static and dynamic ratings will inhabit the same grid. Timely communication of ratings will relieve some of the reliability hazards that TOs face[13].

The IEEE 738 standard is used by many utilities to calculate transmission ratings. The standard describes a method of calculating the current-temperature relationship of bare overhead lines. This standard does not attempt to list actual temperature-ampacity relationships for the any of the many conductors available from industry, nor does it recommend how to appropriately describe weather conditions for the rating of overhead power lines in any particular area or situation. The last revision of this standard took place in 2012 and was finalized in 2013 [11].

There are several opportunities for improvement to modify the static ratings standards, in light of DLR technology advances. Prominent among these is the software program for steady state and transient calculations of temperature and thermal rating of overhead conductors. This standard way of calculating conductor temperature and line ampacity should be replaced by more modern software package to offer multiple benefits; 1) it would allow for simple verification of the program and 2) improve transparency to commercial developers. It is important to update calculations as well as their applications within the standard to accelerate DLR adoption.

F. Other Transmission Challenges

Transmission investment faces a significant amount of capital and risk. Developers hindered by siting and litigation issues may not find recourse through policy changes. Additionally, there are many other industries and investments that can be made to outcompete transmission with lower risk and less hassle. Regulatory certainty is needed to secure investment capital[2].

Transmission projects approved by FERC are often subject to more review and deliberation in state commissions. These individual groups analyze the benefit of transmission with little uniformity. Additional push-back from private interest groups and the public can add further delays. While the DOE has established a specialized group to improve the federal approval timeline, results of this endeavor have not been enough to significantly impact the permitting process[2].

IV. Conclusion

The purpose of this article was to enlighten progress in DLR research, methodology, and review several associated policies. Climatology data was discussed to demonstrate the test bed's variable environmental conditions, focusing on the importance of available wind for dynamic line rating, as it has the largest impact on transmission line cooling. GLASS was introduced as part of INL's methodology for computing thermal and ampacity ratings in real-time, effectively increasing transmission capabilities between 32% and 75% above the static rating. Application of this scheme is easily modified for various locations.

The objective of this research is to provide a clear demonstration that DLR technology is reliable, and allows for industry to openly investigate the results of different methodologies that may be applied to their systems. Reliability continues to stand as the strongest opponent to dynamic line rating.

Further analysis on conductor behaviors, risk, human factors, and weather forecasting is necessary for increased confidence. Model accuracy will be refined by removing uncertainties and assumptions such as steady-state, boundary conditions, imperfect terrain shape, and roughness.

Additional work is needed and ongoing research at INL includes the support to utility planners to better understand the cost structure and benefits of DLR. Work also continues to improve the interoperability with utility transmission control centers and energy management systems through advanced analytics and visualization of critical data. Improving the operator's ability to visualize the improvements will also further enable decisions to be made without the impact to the systems reliability.

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IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix D

Time of Day Final Study Report

Time Of Day

IDAHO POWER
An IDACORP Company

Impact Study
Final Results

September 1, 2014




Time Of Day Study Objectives

- The goal was to conduct a customer behavior study evaluating how the Time Of Day (TOD) pilot pricing plan impacted energy consumption for who signed up during the 2012 plan implementation.

- The Company used a quasi-experimental design structure with TOD participants (Treatment group) and closely matched non-participants (Control group).

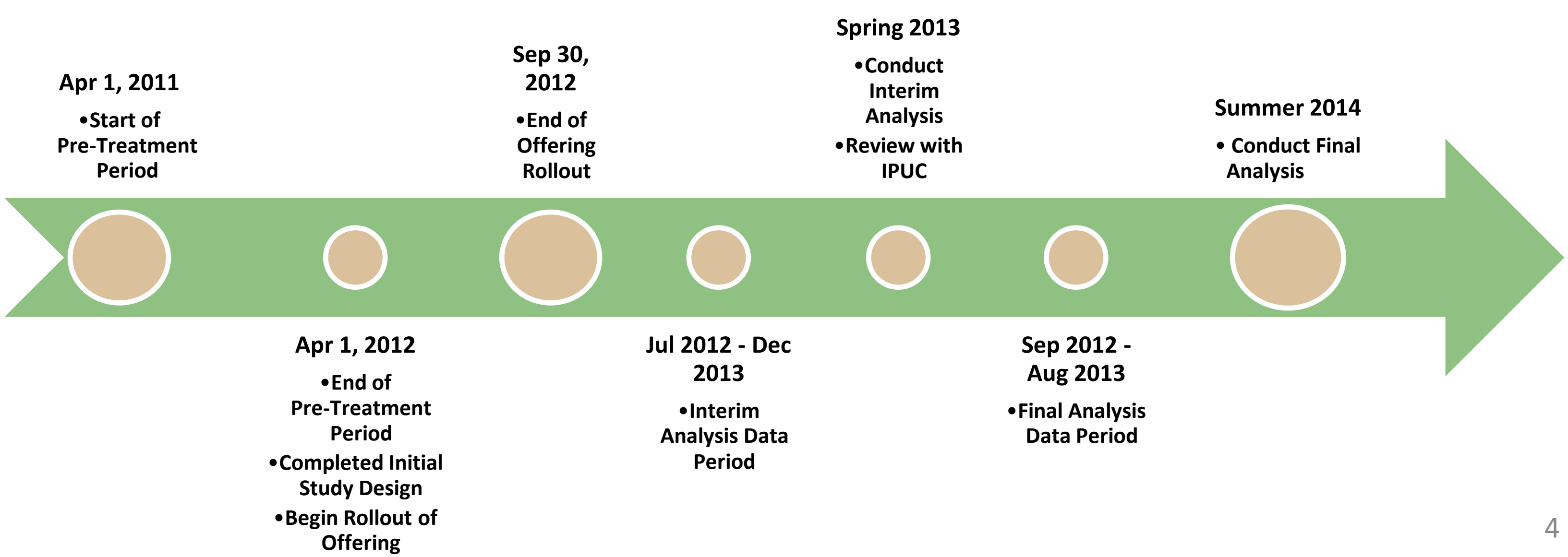
Overall Study Approach

1. Identify Study Parameters and Attrition Risks
2. Identify Population and Stratify
3. Identify Study Sample Frame and Map onto Population Stratification
4. Develop Offering Messaging
5. Roll-out the Offering to all Stratum
6. Target output : Obtain a minimum

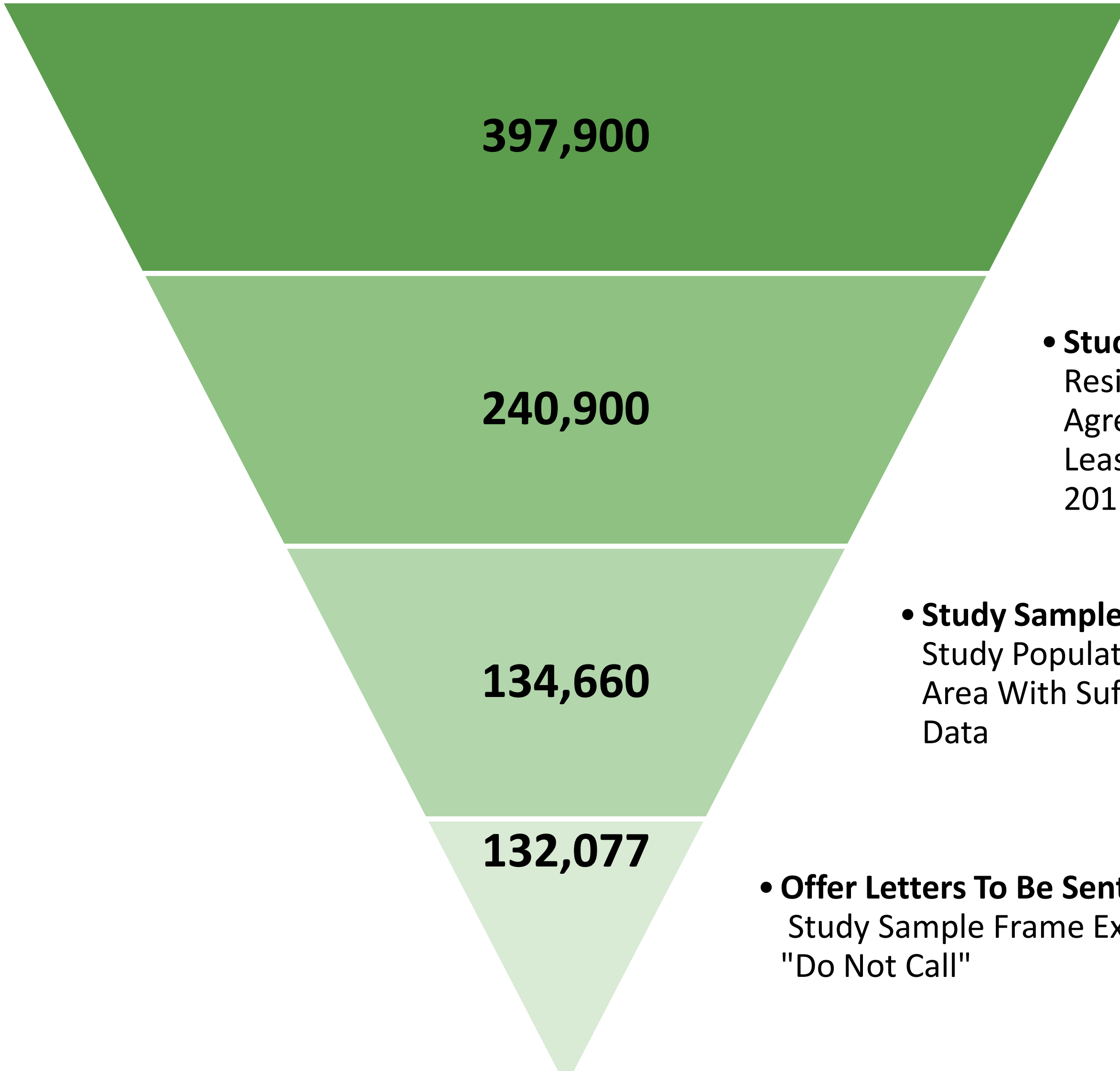
   of 1200 participants without excessive attrition of participants for analysis

Time Periods for The Study

- Pre-treatment Period is April 2011 – March 2012
- Roll out of rate offering April 2012 – September 2012
- Conducted interim analysis (Spring 2013) using service points on the TOD rate on November 1, 2012. Analyzed the period of May-December 2012 as a test of analytic approach
- Integrated feedback from interim analysis into final analysis
- Final analysis (Treatment) Period is Sep 2012 – Aug 2013



Two-Tier Stratification Design



- Active Idaho Residential Service Points as of April 2012
- **Study Population** = Residential SPs Excluding Rental Agreements and Those Not Having at Least 1 Bill > 800 kWh during Apr 2011 - Mar 2012
- **Study Sample Frame** = Study Population of a Specified Geographic Area With Sufficient Pre-Treatment Interval Data
- **Offer Letters To Be Sent** = Study Sample Frame Excluding Customers Requesting "Do Not Call"

Two-Tier Stratification Design

Study Population
240,900 SPs

50% of Population
Low Summer
Avg Jul/Aug/Sep bill
<= **1070 kWh**

50% of Population
High Summer
Avg Jul/Aug/Sep bill
\> **1070 kWh**

Low Summer - Low Winter
50% of Low Summer SPs = 25% of Population
Low Winter Avg Dec/Jan/Feb bill <= **955 kWh**

Low Summer - High Winter
50% of Low Summer SPs = 25% of Population
High Winter Avg Dec/Jan/Feb bill > **955 kWh**

High Summer - Low Winter
50% of High Summer SPs = 25% of Population
Low Winter Avg Dec/Jan/Feb bill <= **1398 kWh**

High Summer - High Winter
50% of High Summer SPs = 25% of Population
High Winter Avg Dec/Jan/Feb bill <= **1398 kWh**

Analysis Methodology

1. Treatment Group: include customers (service points) on TOD any time during the analysis period

2. Match Control group (non-participants) to Treatment Group (participants) using: Zip code, Study Quadrant, and peak vs. off peak usage in the pre-treatment period
   - Do not match on AC Cycling. Excluded AC Cycling Days
   - Select match on minimum weighted Euclidian distance based on seasonal on-peak and off-peak consumption

3. Analyze the treatment TOD group against the matched control group in both the before and after time periods

Difference of Differences Analysis

- Participants on the TOD Rate – [T]
- Closely Matched Control Group – [C]
- Pretreatment Period was April 2011 – March 2012 [0]
- Rolled out rate April 2012 – September 2012
- Analysis (Treatment) Period is September 2012 – August 2013 [1]

$$\text{Impacts} = (\overline{T}_1 - \overline{C}_1) - (\overline{T}_0 - \overline{C}_0)$$

$$\text{Impacts} = \left(\frac{1}{\text{n}_\text{T}} \sum_{i=1}^{n_T} T_{1i} - \frac{1}{\text{n}_\text{C}} \sum_{j=1}^{n_C} C_{1j} \right) - \left(\frac{1}{\text{n}_\text{T}} \sum_{i=1}^{n_T} T_{0i} - \frac{1}{\text{n}_\text{C}} \sum_{j=1}^{n_C} C_{0j} \right)$$

Weighting Quadrants to the Group

Quadrant 1 - Low Summer / Low Winter	Quadrant 2 - Low Summer / High Winter	Quadrant 3 - High Summer / Low Winter	Quadrant 4 - High Summer / High Winter
25% of Study Population	25% of Study Population	25% of Study Population	25% of Study Population
Avg Summer Bill <= 1070 kWh	Avg Summer Bill <= 1070 kWh	Avg Summer Bill > 1070 kWh	Avg Summer Bill > 1070 kWh
Avg Winter Bill <= 955 kWh	Avg Winter Bill > 955 kWh	Avg Winter Bill <= 1398 kWh	Avg Winter Bill > 1398 kWh
26.2% of Study Sample Frame	15.4% of Study Sample Frame	34.3% of Study Sample Frame	24.1% of Study Sample Frame

What Questions Are We Trying To Answer With This Study?

1. Did participants on the TOD rate use less energy overall? i.e. Did overall consumption change?
   a) By Total Group b) By Quadrant

2. Did participants on the TOD rate use more or less energy during peak hours? Did participants use more or less during off peak hours?
   a) By Total Group b) By Quadrant

3. What was the overall response rate to the plan?

4. What was the revenue impact of the pricing plan?

Key to the following graphs

Time Of Day

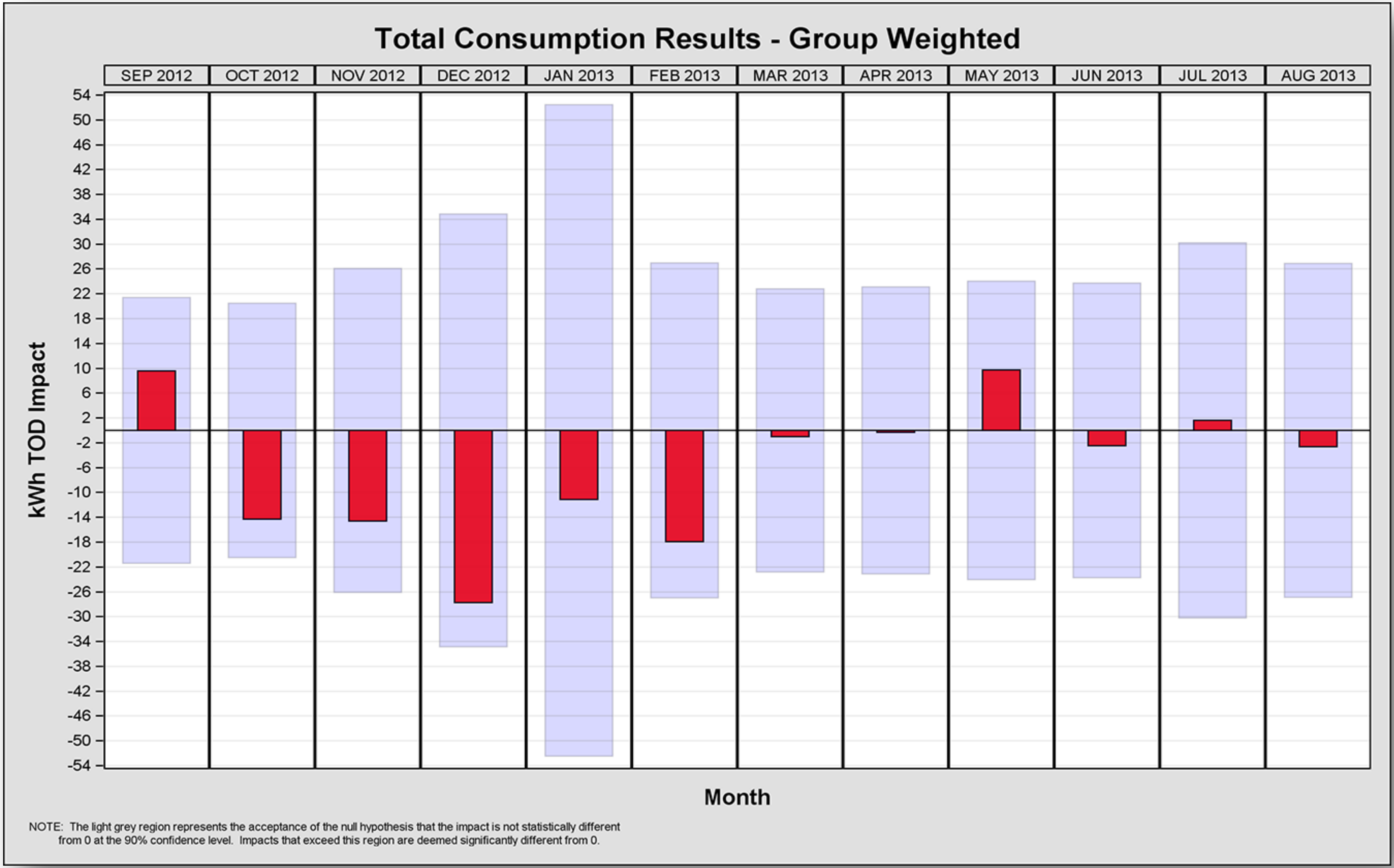
- For the following graphs that show the study findings:
- The red bars show, in kWh, the estimated increase or decrease of usage by month and time of day of the TOD pricing plan participants. The light grey bars behind the red bars represent a "not significant" band. Where the red bar does not extend beyond the light grey bar, then the estimated increase or decrease is small enough that it is within the range of what we might expect to see due to normal random variation and is not statistically significantly different from zero. Where the red bar extends beyond the light grey bar behind it, the results for that month are statistically valid at the 90 percent confidence interval. The graphs either show group total or quadrants. Also, the graphs either show total usage for the month or usage broken into peak and off-peak hours. For the peak and off-peak graphs, the left axis indicates the peak and off-peak results panels of the graph.

Findings

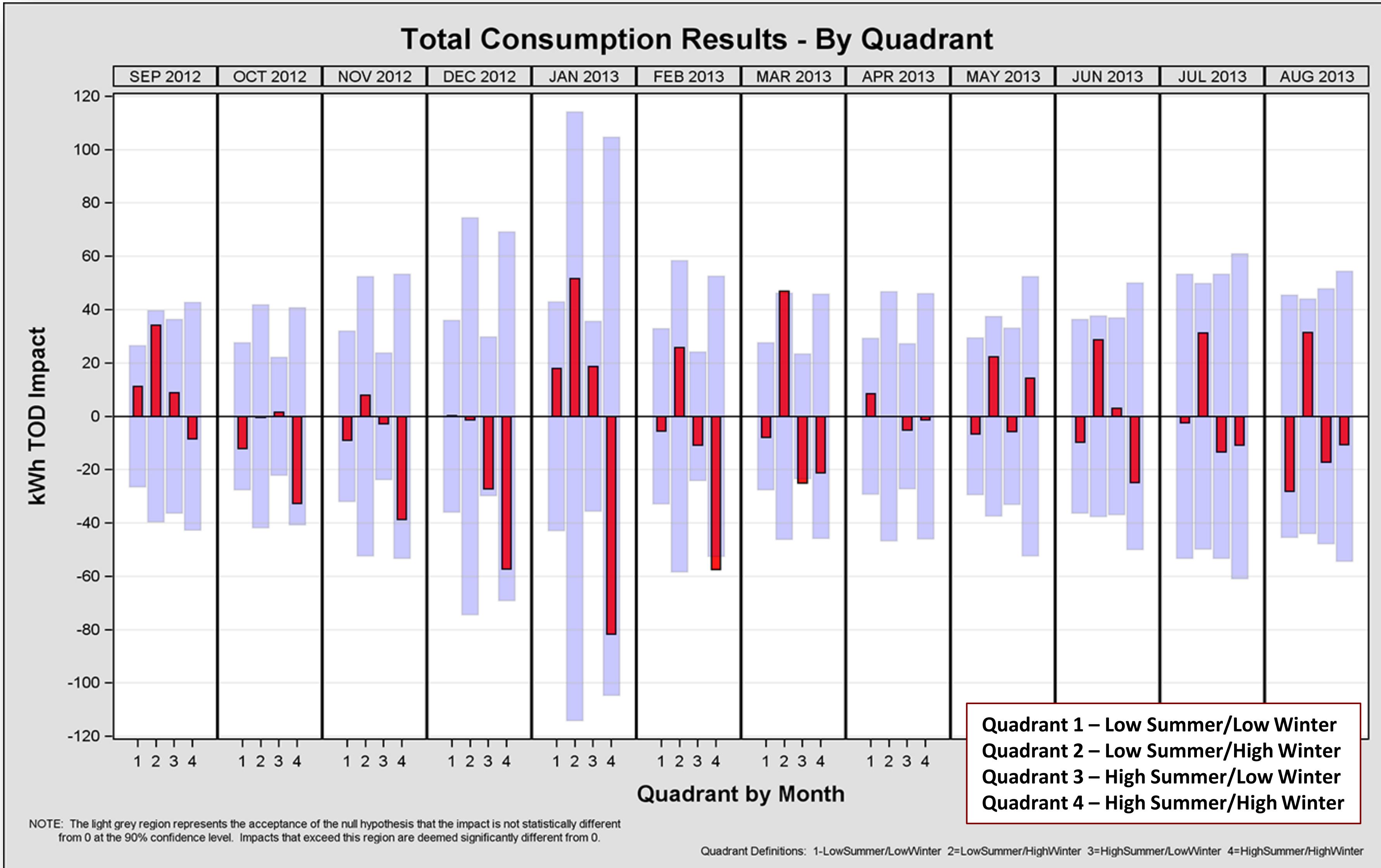
- Did participants on the TOD rate use less energy overall?   i.e. Did overall consumption change?
  - By Total Group
  - By Quadrant

The following two graphs show that there was **no change in overall energy consumption** of plan participants. This was true for the Group Weighted findings and when analyzed by the four different usage Quadrants.

No Change Overall Consumption: by Total Group



No Change Overall Consumption: by Usage Quadrant



Time Of Day

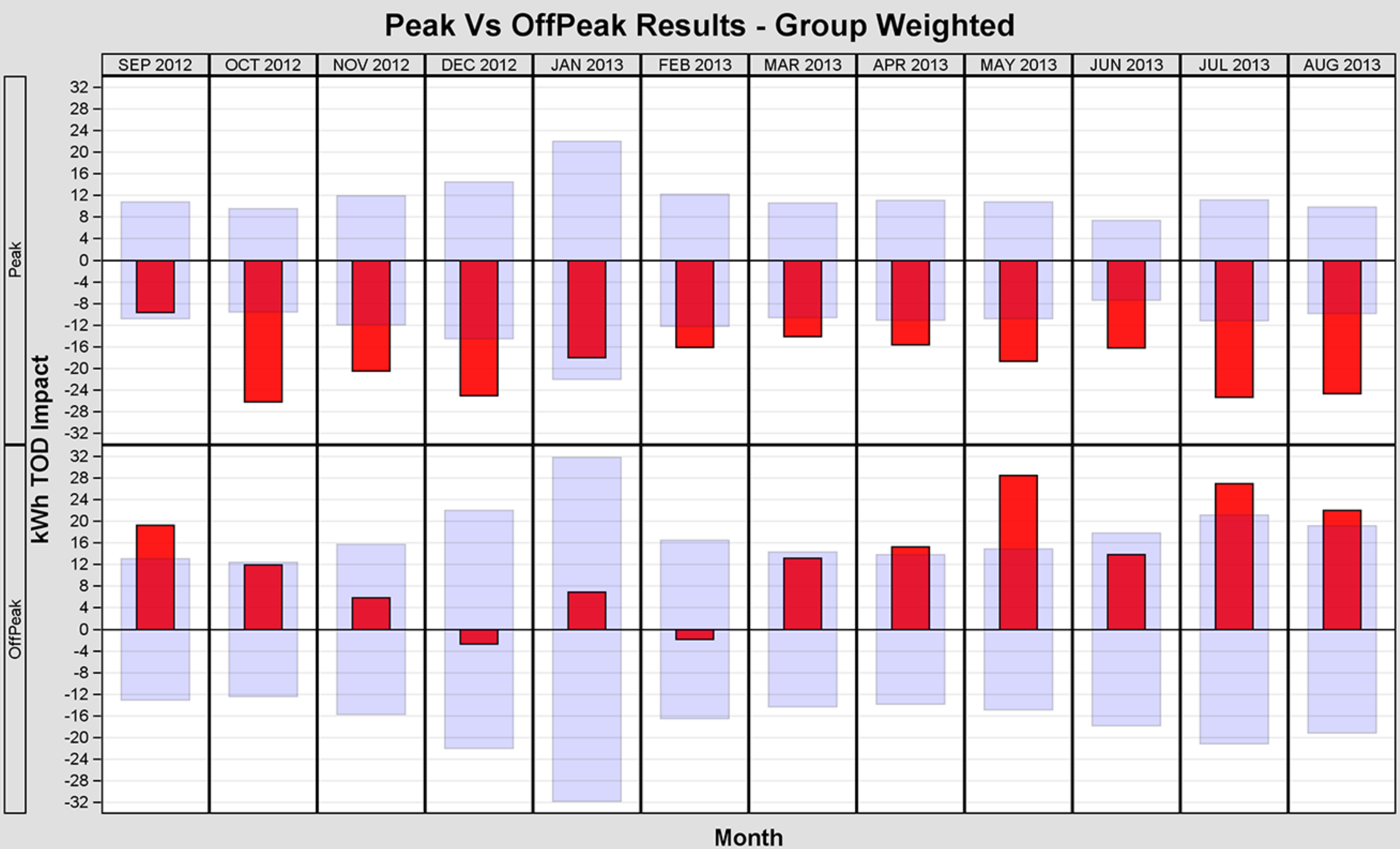
Findings – Total Group

- Did participants on the TOD rate use more or less energy on peak hours? Did participants use more or less during off peak hours?

1. For the study group as a whole, the data analyzed showed a **reduction** in energy use from peak time periods by the analyzed participants of the pricing plan versus the control group.
2. This combined reduction in peak time period consumption was approximately **3 percent** of total kWh use.
3. For the study group as a whole, the data analyzed showed an **increase** in energy use during off-peak time periods by the analyzed participants of the pricing plan versus the control group.
4. This combined increase in off-peak time period consumption was approximately **1 percent** of total kWh.

Peak And Off-Peak Hour Usage Change: by Total Group

Time Of Day



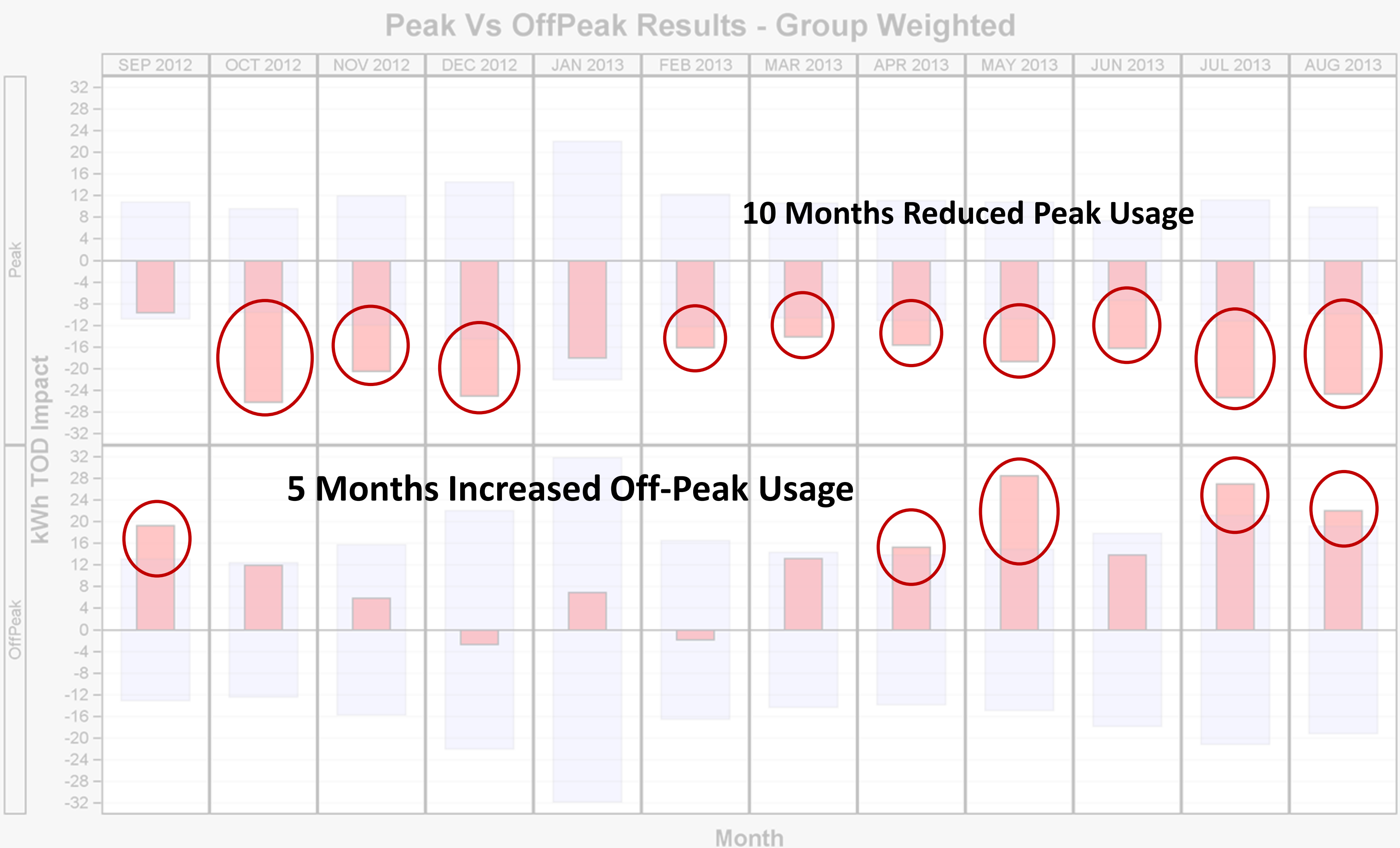
NOTE: The light grey region represents the acceptance of the null hypothesis that the impact is not statistically different from 0 at the 90% confidence level. Impacts that exceed this region are deemed significantly different from 0.

Findings – Total Group

- Did participants on the TOD rate use more or less energy on peak hours? Did participants use more or less during off peak hours?

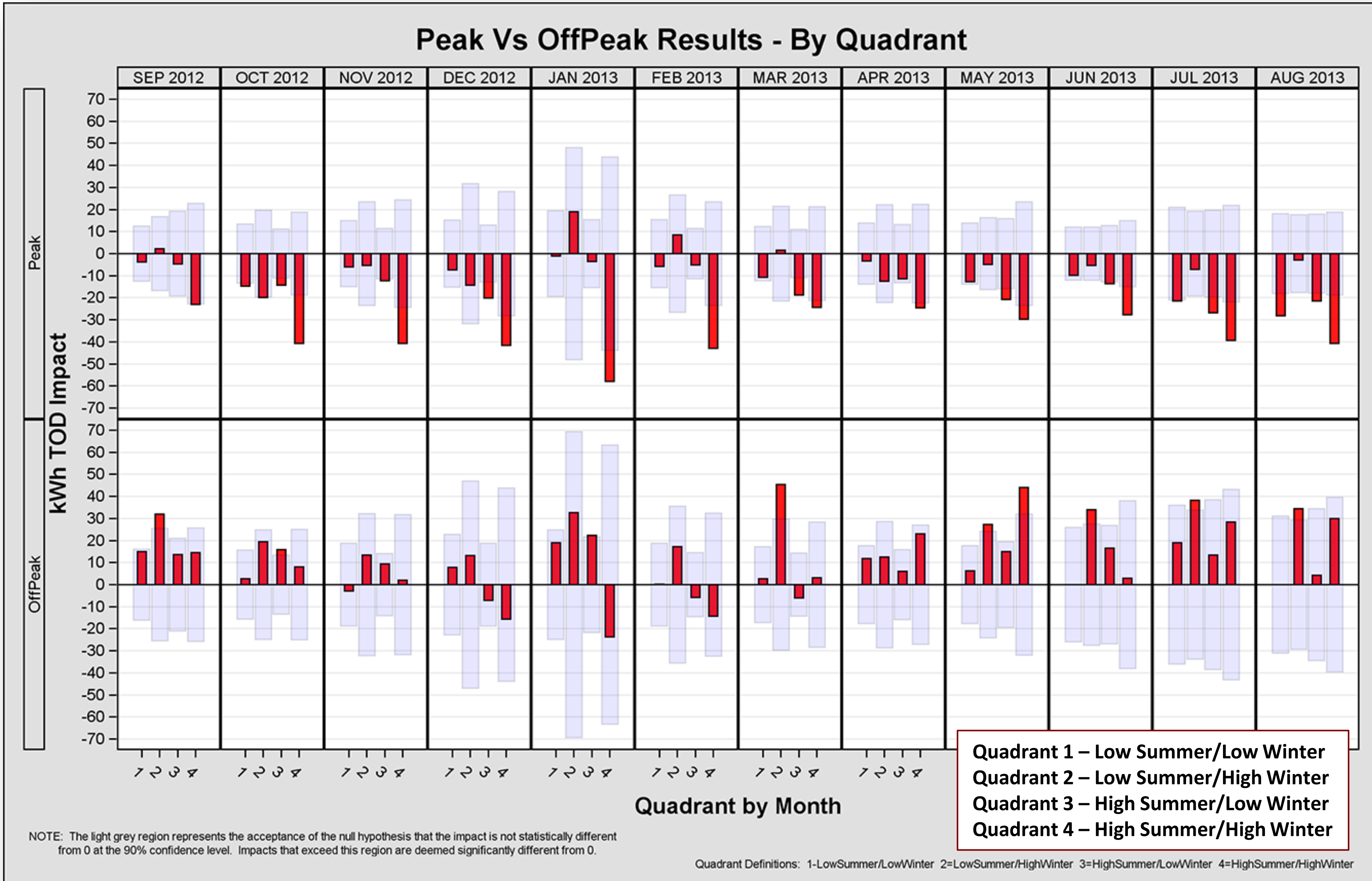
1. All but two months out of 12 months showed statistically significant reductions in energy use during peak periods.
2. Although in 10 months out of the year the average off-peak usage of participants increased, only in five of these months were the results statistically significant.

Peak And Off-Peak Hour Usage Change: By Total Group



NOTE: The light grey region represents the acceptance of the null hypothesis that the impact is not statistically different from 0 at the 90% confidence level. Impacts that exceed this region are deemed significantly different from 0.

Peak And Off-Peak Hour Usage Change: by Quadrant



Findings: Response Rate

Time Of Day

- Estimated general recruitment rate of the offering: **1.3%**
- Number of participants and response rate by usage quadrant:

Quadrant	Participants	Response Rate
Low summer/low winter	**211**	**0.61%**
Low summer/high winter	**243**	**1.19%**
High summer/low winter	**364**	**0.80%**
High summer/high winter	**525**	**1.65%**

- Study findings indicate if Idaho Power were to expand the TOD offering to the remainder of the residential customer population in exactly same manner, approximately **4,000** additional customers would likely sign up assuming customers responded in the same rate as those customers studied.

Findings: Billing Impact

- 12 month shadow bill analysis
- September 2012 through August 2013
- Energy usage not weather normalized
- Actual TOD plan energy billings of all participants compared to standard plan energy billings of all participants
- Study estimates a total revenue reduction of **$119,000**
- This equates to energy billing revenue impact of **-5.48%**

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Appendix E

Transmission Situational Awareness
Oscillation Monitoring Presentation

Idaho Power Company
Smart Grid Investment Grant [or Smart Grid Demo Grant] Update

Dave Angell
dangell@idahopower.com

Data content as of August 2014
Prepared for NASPI Work Group Meeting
October 22-23, 2014

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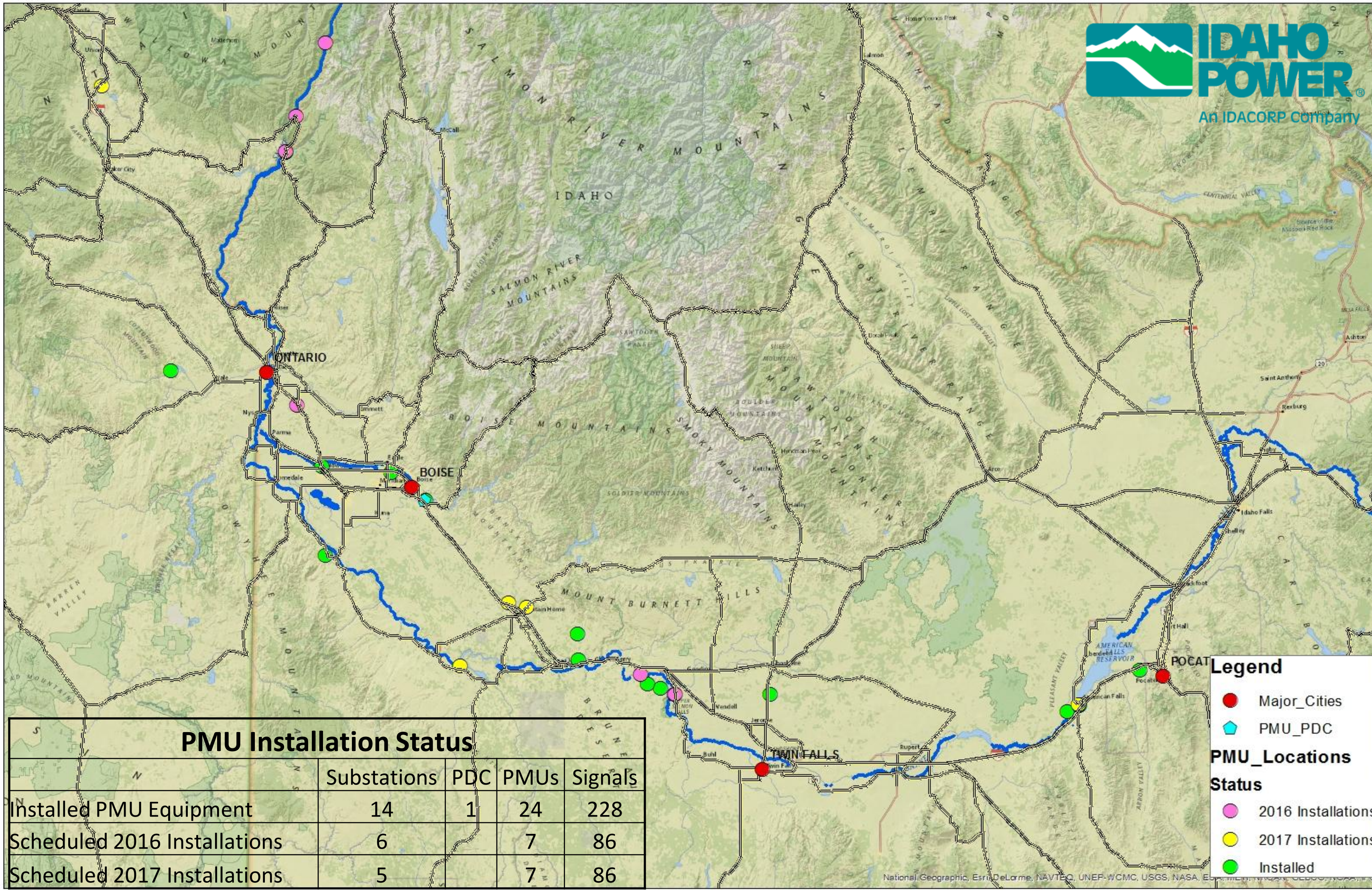
BIG PICTURE

NASPI North American SynchroPhasor Initiative

Project Participants

- Lead sponsor/awardee
  - Dave Angell, dangell@idahopower.com, 208-388-7601
- Project TO/asset owner partners
  - IPCo

Project Map



PMU Installation Status

	Substations	PDC	PMUs	Signals
Installed PMU Equipment	14	1	24	228
Scheduled 2016 Installations	6		7	86
Scheduled 2017 Installations	5		7	86

Synchrophasor project goals

- Situational Awareness
  - Real Time Tools
    - Oscillation Monitoring
    - Voltage Stability
    - Excessive Phase Angle

- Post Event Analysis
  - Off-Line Tools
    - Oscillation Monitoring
    - Voltage Stability
    - System performance
    - Root Cause Analysis *

- Model Validation
  - Plant/Equipment Level
  - Network Elements *
  - Transmission System Level

* Indicates minor change in goals between planning in 2009 and today.

Synchrophasor Uses

- How are phasor data applications being used today (or will be used) in your control room?
  - Being used today
    - phasor data applications are currently <u>not</u> being used in the IPCO control room
  - Will be used in the future
    - phasor data applications will be used to provide situation awareness in the IPCO control room
      - oscillation monitoring
      - voltage stability
      - excessive phase angles across major transmission paths

- How are phasor data applications being used today (or will be used) by your planners?
  - Being used today
    - plant/unit level dynamic model validation using disturbance recording “play-back” tools
      - Wind and hydro-power power plants
    - off-line post-event analysis
  - Will be used in the future
    - Plant/unit level dynamic model validation for NERC MOD-026-1 and NERC MOD-027-1 compliance
    - system level dynamic model validation for NERC MOD-033-1 compliance

Synchrophasor uses (cont.)

- Will you be using PMUs at the distribution level (even for experimental purposes)?
  - Yes – PMUs will be used at the distribution level to collect data for assessing feeder voltage performance and voltage regulation equipment coordination
    - IPCO Generator Interconnection Requirements
      - 8 - 10 MW projects interconnecting to 12.47 kV distribution circuits
      - 16 - 20 MW projects interconnecting to 34.50 kV distribution circuits

Synchrophasor uses (cont.)

- Are you making any additional post-SGIG synchrophasor-related hardware or software investments? If yes, in what and for what purpose?
  - Hardware Investments – Yes (Design and Construction)
    - Fourteen (14) additional PMU Projects over the next three years
    - Purpose - increasing PMU measurements near generation resources/injections
      - » Increased PMU measurements for use in Oscillation Detection Applications
      - » Increased PMU measurements for use in off-line Dynamic Model Validation Applications
  - Software Investments – Yes (Planning and Scoping)
    - Data archiving/data retrieval system improvements of the next three years
    - Purpose
      - Improved PMU data retrieval efficiency
      - Improved PMU data archiving redundancy
      - Improved PMU data visualization
      - Improved PMU system performance monitoring
      - Ability to develop real-time applications and tools

Synchrophasor uses (cont.)

- What outcomes will mean success for this project by the end of 2015?
  - Establishment of plans, processes, and procedures for maintaining a IPCO Synchrophasor Program
  - Completion of scoping and design activities for post-SGIG synchrophasor-related hardware investments
  - Completion of scoping activities for post-SGIG synchrophasor-related software investments

- What key obstacles stand in the way or what problems need to be solved to achieve these outcomes?
  - Key obstacles
    - Human resource availability for Synchrophasor Program Staffing
    - Funding
    - Technology – Production grade real-time operation applications

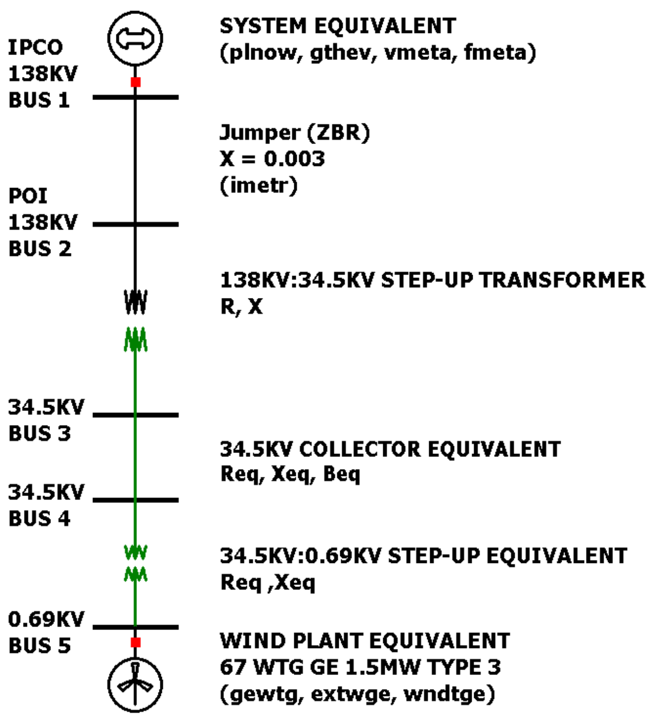
Signs of success

- Value Added
  - Model Validation of Generation Facilities
  - Oscillation Monitoring System Research Project

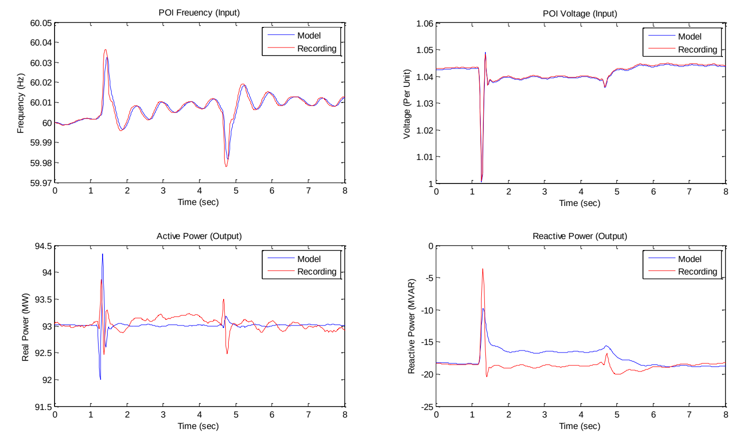
- Money saved from using synchrophasor tools?
  - Model validation using disturbance data rather than staged testing
    - Approx. savings 2-3 days mobilization and testing time per machine

Success stories so far

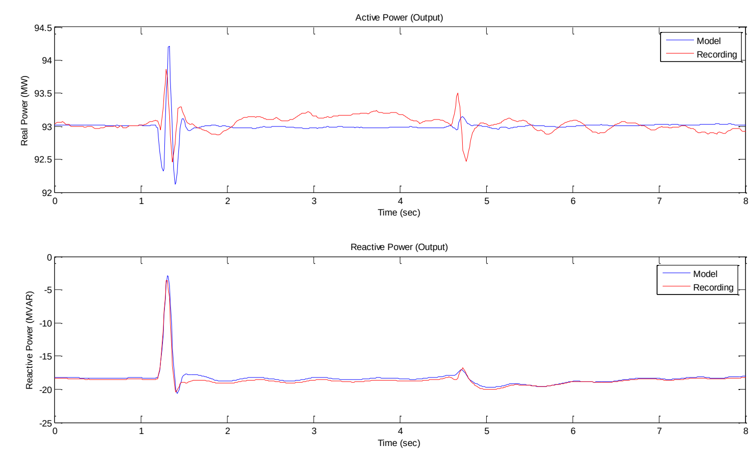
Dynamic Model Validation – Case 1



Pre-Model Calibration

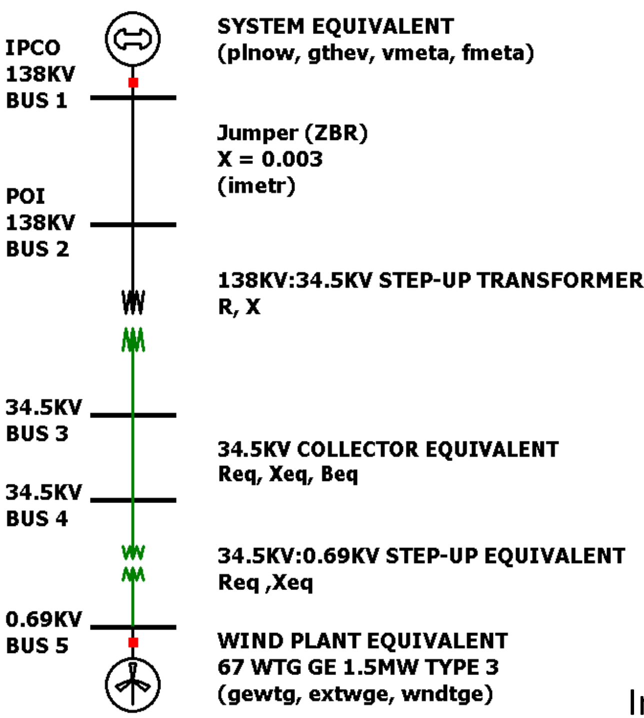


Post-Model Calibration

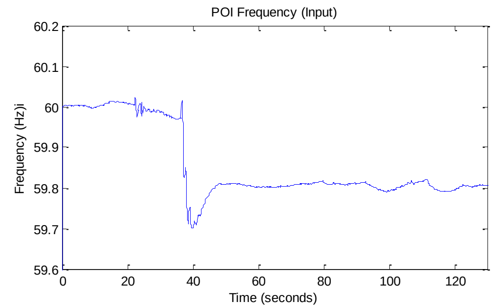


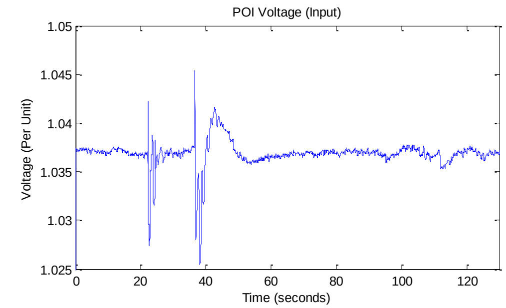
Success stories so far (cont.)

Dynamic Model Validation – Case 2



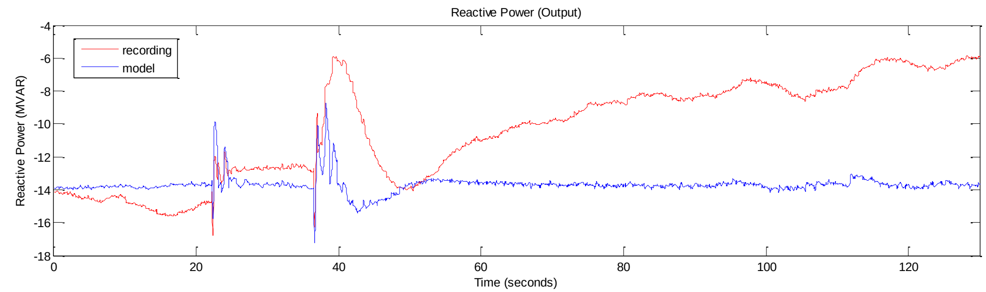
PMU Disturbance Recording



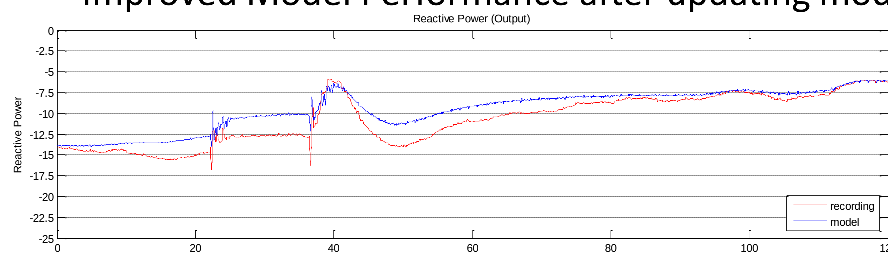


Change in Plant Voltage Control Strategy

– PMU Data indicates poor dynamic model performance and need to update model parameters for this facility

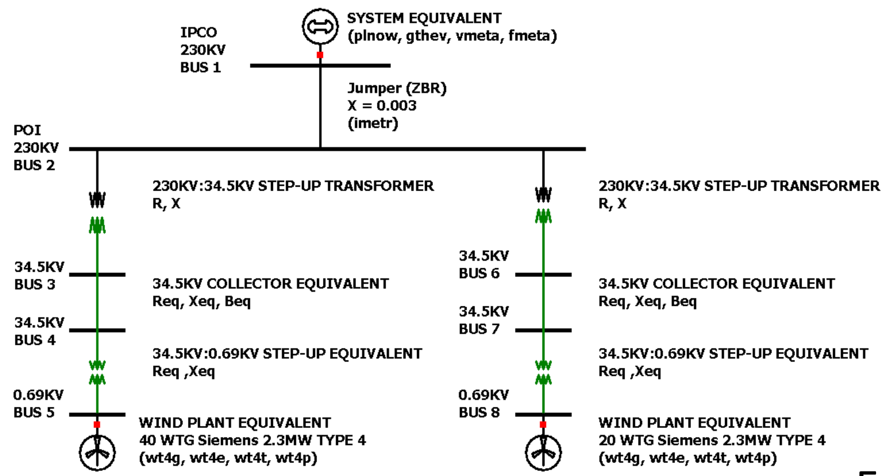


Improved Model Performance after updating model parameters

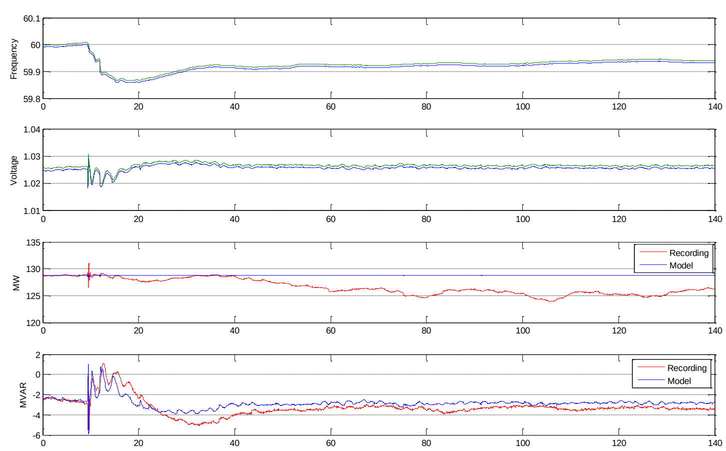


Success stories so far (cont.)

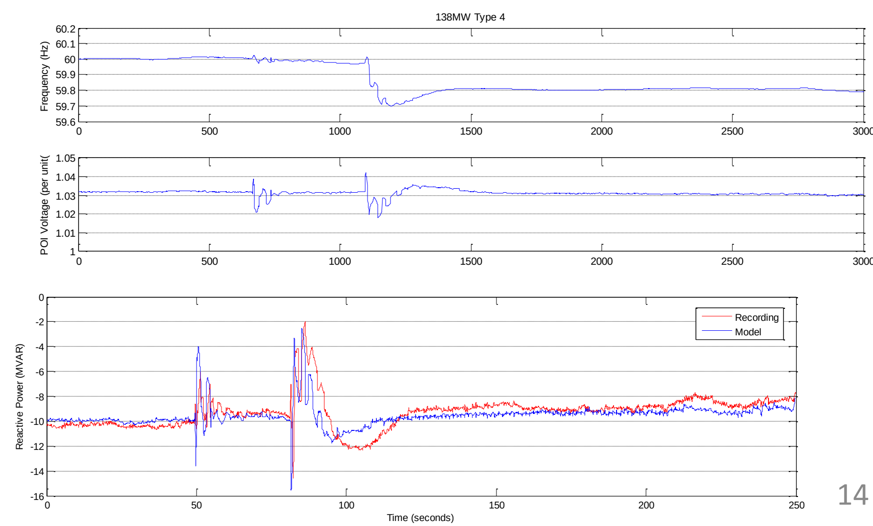
Dynamic Model Validation – Case 3



Event 1



Event 2



Success stories so far (cont.)

Washington State University Oscillation Monitoring System

- Research Project with Washington State University
- Exploration of Real-Time and Off-Line Analysis Tools

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

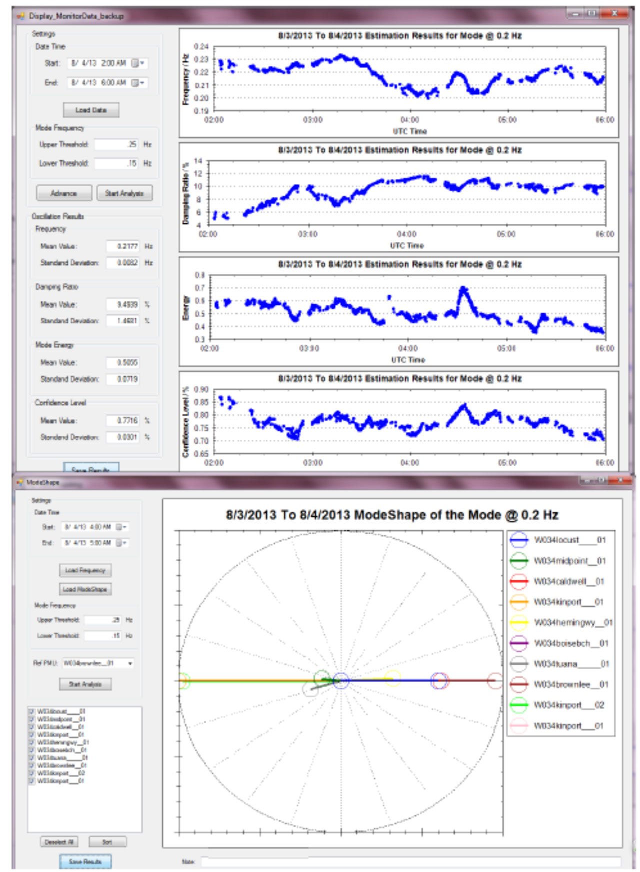
Refresh Rate = 10 seconds

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.



0.2 Hz mode was shown twice, 6am-2pm and 2am-6am the next day, and it was well damped.

Challenges and lessons learned

- What have been your biggest technical challenges?
  - Custom developed software applications
  - Data archive reliability
- What did you do to solve them?
  - Still investigating application solutions
  - Updated software and increased hardware resources
- What have been your biggest programmatic or execution challenges?
  - Establishing reliable data archiving systems. Creating useful and reliable PMU based metrics for dispatch.
  - How did you solve them? Worked with vendors to eliminate performance issues that led to missed data.
- Other lessons or insights about
  - N/A

Synchrophasor training

- No formal training at this time.

Phasor data-sharing

- What are you doing to assure that your project is sharing data with other parties to assure real-time wide-area visibility and situational awareness?
  - IPCO has provided the PEAK RC a list of synchrophasor signals for inclusion in the PEAK RC synchrophasor registry
  - IPCO phasor data shared with the RC is available to operating entities through the PEAK RC WAV tool
- Shared data
  - How many TOs and RCs receive data from your PMUs/project? (list or map)
    - IPCO is sending PMU data to BPA at this time
  - How many TOs and RCs send you their data?
    - IPCO receives PMU data from BPA at this time
    - IPCO is working with PAC to receive PMU data
    - IPCO would like to receive PMU data directly from the RC rather than having to establishing data connections with every individual TO

Phasor data-sharing

- Shared applications
  - How many receive applications output that result from processing real-time phasor data? (list or map)
    - IPCO is neither sending or receiving application output data from processed real-time phasor data
- Will any of this change by 10/2015? (e.g., EIDSN participation?
  - There are no planned changes regarding phasor data-sharing at this time. IPCO makes its phasor data available to entities upon request
- Other measures?
  - None

Phasor data-sharing

- Do you share phasor data for research purposes?
  - Dr. Mani Venkatasubramanian
    - Washington State University
    - Voltage Stability Monitoring System Software Development
    - Oscillation Monitoring System Software Development
  - Dr. Pouyan Pourbeik
    - EPRI
    - Wind Power Plant Model Validation/Model Calibration Software Development

Project timeline from here

SGIG project:

- Are all hardware installations complete?
  - Yes – SGIG project hardware installations are complete
- What are the end dates for your applications installation, testing and analysis?
  - IPCO currently has the following applications installed
    - Open PDC archiver
    - SEL SynchroWAVe Central
    - IPCO developed data Open PDC Reader application
    - WSU VSM/OMS research applications

Project timeline from here

- Now that everything's pretty much installed, what are you working on and monitoring for the last year of the project -- i.e., what should we ask you about next year?
  - IPCO is working on developing plans, processes, and procedures for maintaining a Synchrophasor Program
    - Application technologies are currently being evaluated
    - Improvement of our data archive/retrieval system using OSI-PI are currently being explored
    - Identification of useful real-time visualization tools are being discussed
    - Monitoring PMU/PDC/Archive system performance

Project timeline from here

Post SGIG project

- Working on developing a Synchrophasor program that includes
  - Hardware installations in 2016 and 2017
  - Software applications and visualization platform

Looking forward for NASPI

- What can NASPI do in 2014-2015 to help you make your project more successful or better position synchrophasor technology to become more used, usable and useful?
  - Investigate cost effective operational platforms for viewing and integrating PMU applications.

Looking forward for NASPI

- Research needs – what do we (the synchrophasor community) need to figure out next to help you and synchrophasor technology succeed?
  - Development of voltage stability applications using synchrophasor data that provide useful information for real-time and contingency conditions to Grid Operators and Reliability Coordinators
  - Application development: new PMU applications and code development

DETAILS

NASPI North American SynchroPhasor Initiative

PMUs

- One transmission owners in project and total 24 PMUs by asset owner
- Transmission elements monitored by PMUs (counts include PMU at each end of a transmission element)
  - 3 elements > 345 kV
  - 13 elements > 230 – 345 kV
  - 44 elements 230 kV and below
- % of regional footprint monitored by PMUs
  - 100 % > 300 kV
  - 70% > 200 - 300 kV
- 14 substations with PMUs
- PMU installation rate
  - 24 installed (total, new v. replacements v. upgrades) by EOY 2014 – any more expected?
  - Are your PMUs IEC 37.118-1-2011 compliant? Yes

PDCs and communications

[data below for completed project]

- PDCs
  - RC control centers with PDC: Send PMU data to Peak RC
  - # BA/TO control centers with PDCs: 0
  - # field PDCs: 1
  - PDC availability rate (%/year) – if < 99.5%, No available data but have not had reliability issues with PDC failures
- Communications system
  - Network technology: serial over MPLS from station PMU's to central concentrator.
  - Communication links to TOs: Ethernet to WECC WAN
  - Miles of fiber: Utilizes existing IPCO backbone system
  - System centralized or distributed ownership? If owned, by whom, and who is the vendor? System is owned entirely by IPCO
  - Other details (Phasor Gateways? SIEgate? Phasor Signal Registry? Other?): Request signal names and PMU IDs from Peak RC and information is updated in the Signal Registry.
  - Communications system availability rate (%/year) – if < 99.5%, why? No available data but communication problems were solved by network reconfigurations utilizing a higher bandwidth network.

Communications and data

- Data flows and speeds
  - Phasor data is delivered to PDCs over a serial connection. Generally we run our SEL-487E's at 28.4kbps to the PDC and SEL-421/351A at 19.2kbps
  - PDCs to centrally processed applications; and where are centrally-processed applications hosted?)~500kbps Application servers and archive file servers are located at IT managed data centers.
  - Central applications to users/clients this depends on the amount of data being requested by clients
  - Data speeds and volumes of data for each leg above for Class A data
  - Is all data flowing up to the archive in real time or is there data triage and storage or delayed batch deliveries along the way? If yes, what's being kept or delayed and where? All data is flowing real time to archiving systems.
- Data storage -- Archive/database status – what's stored in the field and what's archived in central facilities
  - Storage size. ~4TB for 12 month storage.
  - Age/duration of data to be readily accessible. 12 Months
  - Is data access query process mature and workable? Some applications offer better data retrieval capabilities than others, currently PI offers the greatest ease of use in this regard.
  - Total volume of data being generated by your phasor data system?
    - PMU sampling rate. 30 Samples per second
    - Number of PMUs, number of phases monitored/PMU, number of data points measured per sample, number of data points calculated per sample
    - Total volume data sent up by minute
    - Total volume data being generated and stored per year? ~4TB
- Data compression and triage
  - Using data compression? No, there were performance issues with lossless data compression and maintaining a separate version of OpenPDC which implemented lossless compression for archiving wasn't worth the size reductions.
  - Triage or reduce data before sending it from PMU upstream to applications and storage? no
  - Pre-condition data before sending it to specific applications? We are doing this with our trial PI Server, using a 3rd party calculation engine to calculate voltage stability and oscillations before sending to PI for archiving.

Data quality and availability

- Lessons learned regarding data quality improvement? Archive and PDC software performance caused some early data availability issues. Increasing available resources and fixes from vendors have fixed this.

Major operational applications using phasor data

- Wide-area situational awareness
  - PEAK RC WAV
    - Integrated into other control room applications?
      - Not yet Integrated
    - Operational date
      - 2013
  - Oscillation Monitoring System/ WSU Software
    - Integrated into other control room applications?
      - Not yet Integrated
    - Operational date
      - uncertain
  - Voltage Stability Monitoring System/ WSU Software
    - Integrated into other control room applications?
      - Not yet Integrated
    - Operational date
      - uncertain

Major operational applications using phasor data

- Renewable generation integration
  - MW monitored by PMUs
    - 380 MW of Wind Resource
  - Integration technique and applications; software or vendor used?
    - No applications currently used for integration
    - Currently used for off-Line analysis for dynamic model validation
  - Operational date
    - Uncertain date for integration techniques and applications

Major operational applications using phasor data

- State estimation
  - DOE Grant to develop software
    - V & R Energy
  - Operational readiness date
  - ~ 2017
- Other?
  - WSU Oscillation Monitoring System Research Application
  - WSU Voltage Stability Monitoring System Research Application

Major operational applications using phasor data

- Are your operators and operations support engineers using these applications?
  - Operators and operations support engineers are not using these applications.
- Why or why not?
  - The available applications are still in test & development mode and not ready for porting to the operations environment for use as real-time production tools.
- What impacts or benefits are you anticipating; have you observed any to date?
  - Benefits observed to date
    - Identification of dynamic models needing improvement
  - Anticipated Benefits
    - We expect these tools to provide a better situational awareness to the operators and provide sufficient lead time to perform effective mitigation actions.
- What obstacles have you identified and how are you addressing them?
  - Obstacles
    - Human resources to provide continuous synchrophasor program support
    - Funding for completing development of applications
    - Clear identification of useful operational benefits of synchrophasor applications
    - Sub-optimal system performance/data archiving performance
  - Next Steps
    - Develop a Synchrophasor Program plan
    - Clear identification of real-time synchrophasor application needs/useful operational benefits of synchrophasor applications
    - Contact other TOs/industry partners to gather additional information
    - Currently developing a business case for management review

IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix F

Peak Reliability Press Release

PEAKRELIABILITY
assuring the wide area view

FOR IMMEDIATE RELEASE

Media Contact Peak Reliability:

Rachel Sherrard
(360) 213 2674
rsherrard@peakrc.com

Date: June 13, 2014

U.S. DOE Awards Peak Reliability approximately $3.9 million to build on successful Western Interconnection reliability efforts

VANCOUVER, Wash. — The U.S. Department of Energy (DOE) has awarded Peak Reliability, approximately $3.9 million in funding to build on its successful Western Interconnection Synchrophasor Program (WISP), which was completed on schedule in March 2014. The funding matches dollars committed by seven WISP partners to extend and deploy synchrophasor technologies. The total funding for this new grant is approximately $7.8 million.

WISP utilizes newly installed synchrophasor technology to obtain data that provides a more comprehensive and precise view of the Western Interconnection. With WISP, system operators can visualize power system disturbances, and can take preventative measures to minimize the risk of these disturbances from evolving into a major, systemwide event.

Peak Reliability will use the grant to improve the quality and use of the synchrophasor data it receives from 584 phasor measurement units (PMUs), which were installed throughout the Western Interconnection by WISP participants.

“This is an excellent opportunity to more fully operationalize the wealth of data that we’re getting from the PMUs in the field,” said Gary Stephenson, Peak Reliability President and Chief Executive Officer. “This is another great step forward for Western Interconnection reliability.”

In 2010, the Western Electricity Coordinating Council (WECC) received $53.9 million in funding from DOE. The funding, awarded under the American Recovery and Reinvestment Act’s Smart Grid Investment Grant initiative, matched dollars committed by nine WISP partners to extend and deploy synchrophasor technologies within their western electrical systems. The total funding for WISP was $107.8 million.

Peak Reliability applied for the additional grant, subsequent to the bifurcation of WECC into a Regional Entity (WECC) and a Regional Coordinator (Peak Reliability).

Improving grid performance

Now that a sophisticated infrastructure for the measurement, transmittal, use and archiving of time-synchronized phasor measurements has been deployed, Peak Reliability will work to improve grid performance in the following five focus areas:

1. Manage and improve data quality;
2. Correlate synchrophasor measurements with Interconnection behavior and performance;
3. Integrate application results with operational documentation/procedures;
4. Deploy automatic controls; and
5. Make data availability efficiency improvements, including deploying a more efficient and reliable system for distributing synchrophasor data.

Peak Reliability's efforts should realize measurable benefits, including:

1. Avoiding cascading electrical failure;
2. Making full use of available transmission capacity; and
3. Improving data delivery system efficiency.

The project's participants are: Peak Reliability, Bonneville Power Administration (BPA), Southern California Edison (SCE), the California Independent System Operator (CAISO), Idaho Power Company (IPC), San Diego Gas and Electric (SDG&E), V&R Energy Systems Research, Inc., and Alstom Grid, Inc.

Peak operates two reliability coordination offices, one in Vancouver, Washington (which also houses its corporate office) and the other in Loveland, Colorado. To learn more about Peak Reliability and its services, please visit www.peakrc.com.

***

NOTES:
Peak: provides situational awareness and real-time supervision of the entire Western Interconnection. Peak operates two reliability coordination offices, one in Vancouver, Washington and the other in Loveland, Colorado. Peak has the highest level of authority for the reliable operation of the Western Interconnection Bulk Electric System. Peak works with Balancing Authorities, Transmission Owners, and Transmission Operators to minimize disruptions, provide leadership, and help assure reliability.

Synchrophasors: are precise grid measurements from PMUs. The measurements are taken at high speed and are synchronized to give a more precise and comprehensive view of the entire Interconnection compared with conventional technology. Synchrophasors enable a better indication of grid stress, and can be used to inform corrective actions to maintain reliability. (source: www.NASPI.org).

Synchrophasor technology also can provide the ability to see and manage the intermittent nature of renewable resources, and to deploy the ancillary services needed to solidify the changing nature of the West's generation fleet.

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2014 SMART GRID REPORT

Appendix G

Conservation Voltage Reduction Enhancements
Project Plan

DELIVERY PLANNING
RESEARCH, DEVELOPMENT AND DEPLOYMENT

Conservation Voltage Reduction Enhancements Project
PROJECT PLAN

DATE
4/21/2014
(Rev1.0 – 9/1/14)

TABLE OF CONTENTS

INTRODUCTION

Conservation Voltage Reduction (CVR) is a term used to describe a method for decreasing energy use by decreasing the voltage on a feeder. By reducing feeder voltages by just a minimal amount, significant energy can potentially be saved by our customers. Idaho Power implemented a CVR program in 2009 and the program currently includes nine substations. This CVR program was instituted at minimal cost by simply changing the tap settings on distribution substation transformer load tap changers (referred to herein as "one control point"). Only a very small number of feeders qualify for CVR using this method because of low voltage issues that can result at certain locations along the feeder. Also, controlling only at the transformer load tap changer, every feeder connected to an individual transformer must qualify for CVR status. So, even if only one feeder has low voltage issues, the entire group of feeders connected to a given transformer would not qualify.

A further complication that comes from operating a static, one control point program is that as an individual feeder's load characteristics change based on season, little can be done to adjust the voltage to compensate. Load growth also changes the voltage profile of a feeder. As a result, a feeder that may qualify for CVR may not be qualified soon after CVR is initiated without significant upgrades. Additionally, energy and demand savings associated with CVR can vary tremendously from month to month.

Idaho Power has identified a number of additional feeders that could qualify for CVR if upgrades to either the conductors or the voltage regulation equipment were made. However, these upgrades are very costly and we have not fully quantified the existing system's cost benefits so they can be applied to new feeders. Furthermore, there are likely other technologies that could be applied to upgrade a feeder that may be less costly than reconductoring.

PROJECT MANAGEMENT APPROACH

The Project Manager has the overall authority and responsibility for managing and executing this project according to this Project Plan. The project team will likely consist of personnel from the following departments: T&D Reliability Engineering, Regional Operations/Metering, T&D Planning, Power Quality, and others as appropriate. The Project Manager will work with all resources to perform project planning. All funding decisions will be made by the project sponsor.

The project team will be a matrix in that team members from each organization continue to report to their organizational management throughout the duration of the project. The Project Manager is responsible for communicating with organizational managers on the progress and performance of each project resource.

PROJECT SCOPE

The scope of the ***CVR Enhancements Project*** is to:

1) Validate the energy and demand savings associated with CVR at the customer level
2) Quantify the costs and benefits associated with implementing CVR
3) Determine methods for expanding the CVR program to additional feeders
4) Pilot methods for making Idaho Power's CVR program more dynamic
5) Determine methods for ongoing measurement and validation of the CVR program's effectiveness

The outcome of this project will be a robust CVR program that can be more fully utilized across the Idaho Power system.

MILESTONE LIST

The chart below lists the major milestones for the ***CVR Enhancements Project***. If there are any scheduling delays which may impact a milestone or delivery date, the project manager must be notified immediately so proactive measures may be taken to mitigate slips in dates. Any approved changes to these milestones or dates will be communicated to the project team by the project manager.

Milestone	Description	Date
Validation Method Determination	Determine and define the method or methods that will be used for data collection and validation	Dec. 31, 2014
Draft OPUC Report Section	CVR project update for insertion to Smart Grid Report draft to OPUC	May 15th of each year
OPUC Report Section	CVR project update for insertion to Smart Grid Report final to OPUC	Sept 15th of each year
Complete Data Collection	Collect data from treatment and control groups representing varied customer classes over course of 1 year	Dec. 31, 2015
Complete Pilot Project(s)	Operate one or more pilot projects aimed at improving CVR performance	Dec. 31, 2015
Cost Benefit Analysis	Perform cost/benefit analysis on data captured during 2015	May 31, 2016
Program Description/Definition	Create documentation that describes in a detailed manner what the mature CVR program should look like.	June 30, 2016
Final Report		September 1, 2016

DELIVERABLES

There are a number of documents and reports that will be produced periodically throughout the course of the ***CVR Enhancements Project***. The following are descriptions and delivery date.

Report	Due Date
Existing CVR Program Report	August 29, 2014
CVR Project Update for inclusion in *Draft* OPUC Smart Grid Report	May 31, 2014, 2015 & 2016
Potential Methods for Analyzing and Improving CVR	May 31, 2014 (dynamic document)
CVR Project Update for inclusion in OPUC Smart Grid Report	Sept. 15, 2014, 2015 & 2016
Validation Method Definition and Procedure Document	Dec. 31, 2014
Complete Data Collection/Report on Data Repository Contents	Dec. 31, 2015
CVR Cost/Benefit Analysis Report	May 31, 2016
CVR Program Structure and Layout Document	June 30, 2016
CVR Operating Procedures Manual	June 30, 2016
***CVR Enhancements Project* Final Report**	September 1, 2016

WORK BREAKDOWN STRUCTURE

The ***CVR Enhancements Project*** Work Breakdown Structure is comprised of 15 tasks as described below.

1.0 Develop Existing CVR Program Report (Start: 3/3/14➔End: 8/29/14)

Under this task, a report will be developed within which will be gathered the various pieces of information regarding Idaho Power's existing CVR program. A clear repository of information will be developed and linked to from within the report or CVR SharePoint. Additionally, the energy and demand savings will be estimated for feeders in the existing program and the results recorded in this report.

- 1.1 Background of CVR at Idaho Power
- 1.2 Feeders on which CVR is already implemented
- 1.3 Feeders identified for future CVR implementation
- 1.4 CVR savings calculations
- 1.5 Produce report

2.0 **Develop method(s) to calculate CVR factors as a function of time, geographical location, and dominant customer type (Start: 3/3/14➔End: 8/29/14)**

The CVR Factor is a measure of load reduction as a function of voltage and is used to measure the effectiveness of a CVR program. It is defined as the percentage reduction in load resulting from a 1% reduction in voltage.

$$\text{CVR Factor} = \Delta E / \Delta V$$

CVR Factors can range from 0.5 to 1.0 and in some cases, exceed 1.0. It is dependent on the load characteristics of a feeder.

The characteristics of demand on a feeder change as a function of time (seasonally and hourly) which means the CVR factor is not a static number but changes often. Additionally, the CVR factor varies by customer type and geographic location.

This task will develop methods to calculate the CVR factor for individual customer classes taking into account seasonality, time of day, and geographic location. The chosen method will be applied across Idaho Power's service territory and be used in determining which transformers are good candidates for inclusion in the CVR program.

3.0 Develop Method(s) to Analyze Savings from CVR (Start: 3/3/14➔End: 8/29/14)

There are a number of different methods that could be used to analyze the energy savings resulting from the use of CVR. For example, energy savings or demand reduction could be measured by evaluating the load changes on an individual transformer due to voltage change associated with CVR. Control could be performed with the CVR on for an entire day followed by CVR off on a similar day then the results compared. Alternately, two separate, though similar transformers could be compared; one with CVR active and one with no CVR. There are many different variations within these two alternatives and there are also other completely different alternatives (scenarios) that could be used. This task will evaluate the various scenarios and choose a method for use in Task 8.0.

- 3.3 Survey different techniques used by other utilities.
- 3.4 Develop Primer Document that describes the results of the technique search
- 3.5 Determine which method to use to validate CVR benefits

4.0 Develop method(s) to capture CVR savings (Start: 3/3/14➔End: 8/29/14)

There are ways to enhance the effectiveness of Idaho Power's CVR program without the need to install additional line equipment other than measurement devices. One such method is to dynamically control the transformer LTC settings such that they change in response to changes in feeder loading.

This task will evaluate and develop methods to make the existing system more dynamic without installing additional line equipment.

- 4.1 Survey different techniques used by other utilities
- 4.2 Investigate new equipment for controlling load tap changers
- 4.3 Determine control limitations for load tap changers
- 4.4 Determine which equipment and methods will be used for controlling load tap changers

5.0 Evaluate and select method to enhance CVR cost effectiveness (Start: 3/3/14➔End: 8/29/14)

Various methods could be adopted that would allow the CVR program to expand to previously unqualified feeders and substations. Under this task, research will be performed looking for methods other utilities have used to enhance their CVR programs. Additionally, new methods not tried at other utilities may be evaluated.

- 5.1 Feeder voltage regulator control
- 5.2 Static voltage control devices
- 5.3 Remote controlled load tap changers
- 5.4 Integration into future Volt/VAR Management System (VVMS)

Milestone: Place purchase order for data collection and pilot devices (9/30/14)

There are potentially a number of different technologies that will be tested for use in Idaho Power's CVR program. Depending on technology chosen in Task 5.0, the following devices will be placed on order:

- Transformer load tap changer controllers
- Protective relaying devices
- Static voltage control devices
- Metering equipment
- Smart Grid Monitoring (SGM) devices
- TWACs equipment

6.0 Make preparations to collect data on selected CVR customer groups(Start: 9/1/14➔End: 12/31/14)

Based on the method determined and defined in Task 2.0, the effects CVR has on demand and energy will be analyzed. Representations of different customer classes will be monitored over a year with data being collected that will be used to analyze CVR effectiveness.

- 6.1 Choose control and treatment groups
  - 6.1.1 Determine protocol that will be used for analysis
- 6.2 Prepare for data collection
  - 6.2.1 Setup systems for collecting data
  - 6.2.2 Create database

7.0 Collect Data on selected customer groups associated with Task 2.0 (Start: 1/1/15➔End: 12/31/15)

- 7.1 Collect AMI data and any other pertinent data to analyze their load characteristics and quantify CVR effects on load. Data collection to occur over 1 year (2015)

8.0 Collect Data on selected CVR customer groups associated with Task 3.0 (Start: 1/1/15➔End: 12/31/15)

8.1 Collect AMI data and any other pertinent data to analyze their load characteristics and quantify CVR effects on load. Data collection to occur over 1 year (2015)

9.0 Collect Data on selected CVR customer groups associated with Task 4.0 (Start: 1/1/15➔End: 12/31/15)

9.1 Collect AMI data and any other pertinent data to analyze their load characteristics and quantify CVR effects on load. Data collection to occur over 1 year (2015)

10.0 Analyze CVR Data(Start: 4/1/15➔End: 5/31/16)

Based on the analysis performed in Task 3.0, the costs and benefits associated with CVR will be quantified. It is anticipated that the method(s) used to quantify the benefits will be chosen such that they will be recognized as valid by regulatory agencies. That is, we will either choose an industry standard Cost/Benefit analysis method or define a method that can be defended as valid when presented to regulators.

11.0 Define Final CVR Program Structure and Layout (Start: 9/1/15➔End: 6/30/16)

In preparation for rollout of Idaho Power's enhanced CVR program, this task will define the program structure and layout. It will also setup procedures for program operation and maintenance and define the method or methods to be used for ongoing measurement and validation of program effectiveness.

- 11.1 Program structure
- 11.2 Program operation
  - 11.2.1 Stand-alone or operated as part of VVMS or DMS
- 11.3 Program maintenance
- 11.4 Method(s) for ongoing measurement and validation of program effectiveness
- 11.5 Method for qualifying new transformers for CVR

12.0 Determine CVR Program Rollout (Start: 11/2/15➔End: 7/29/16)

This task will determine which substation transformers to include in the enhanced CVR program. It will determine and define a staged rollout of CVR on these transformers.

- 12.1 Based on cost/benefit, determine:
  - 12.1.1 Transformers to include in the CVR program
  - 12.1.2 Staged rollout

13.0 Write Operating Procedures Manual (Start: 12/1/15➔End 6/30/16)

This task will put together a Procedures Manual so the program is operated and expanded in a controlled and formal manner. It will define and assign rolls so responsibility can be assigned for the ongoing operations of the CVR program.

13.1 Control setpoint changes
13.2 Disabling CVR on a transformer
13.3 Qualifying new transformers to include in program
13.4 Change control

14.0 Write Report (Start: 4/1/16➔End: 7/31/16)

14.1 Issue final ***CVR Enhancements Project*** report.
14.2 Draft to be complete May 31, 2016
14.3 Final to be complete July 31, 2016

15.0 Remove Pilot Equipment (Start: 1/1/16➔End: 6/30/16)

15.1 This task may be avoided if it is determined that the pilot equipment should be left in-place
15.2 This task will likely be accomplished under other Project Plans

Change Management Plan

Any changes to either the scope or final scheduled delivery date for the ***CVR Enhancements Project*** must be approved by the project sponsor: Leader, T&D Planning. Project Manager may approve schedule changes that do not affect the final delivery date.

Communications Management Plan

This Communications Management Plan sets the communications framework for this project. It will serve as a guide for communications throughout the life of the project and will be updated as communication requirements change. This plan identifies and defines the roles of project team members as they pertain to communications. It also includes a communications matrix which maps the communication requirements of this project, and communication conduct for meetings and other forms of communication. A project team directory is also included to provide contact information for all stakeholders directly involved in the project.

The Project Manager will take the lead role in ensuring effective communications on this project. The communications requirements are documented in the Communications Matrix below. The Communications Matrix will be used as the guide for what information to communicate, who is to do the communicating, when to communicate it, and to whom to communicate.

Communication Type	Description	Frequency	Format	Participants/ Distribution	Deliverable	Owner
Status Report	SharePoint summary of project status	Monthly	Share Point	RD&D Leader, Project Team and Stakeholders	Status Report	Project Manager
Project Meetings		As needed	In Person	Project Team	Meeting Minutes	Project Manager
Project Review	Present metrics and status to sponsor	Bimonthly	In Person	Project Sponsor	Status and Metric Presentation	Project Manager
Change Review	Review any Change Requests	As Needed	In Person	Project Sponsor and Project Team	Change	Project Manager

Communications Conduct:

Meetings:
The Project Manager will distribute a meeting agenda at least 2 days prior to any scheduled meeting. During all project meetings the Project Manager will ensure that the group adheres to the times stated in the agenda and the recorder will take all notes for distribution to the team upon completion of the meeting. Meeting minutes will be distributed no later than 3 working days after each meeting is completed.

Procurement Management Plan

The Project Manager will work with the project team to identify all items or services to be procured for the successful completion of the project. Any procurement made as part of this project must be approved by the project sponsor.

Project Scope Management Plan

Scope management for the ***CVR Enhancements Project*** will be the sole responsibility of the Project Manager. The scope for this project is defined by the Scope Statement and Work Breakdown Structure.

Proposed scope changes may be initiated by the Project Manager, Stakeholders or any member of the project team. All change requests will be submitted to the Project Manager who will then evaluate the requested scope change. Upon acceptance of the scope change request the Project Manager will submit the scope change request to the Project Sponsor for acceptance. Upon approval of scope changes by the Project Sponsor the Project Manager will update all project documents and communicate the scope change to all stakeholders. Based on feedback and input from the Project Manager and Stakeholders, the Project Sponsor is responsible for the acceptance of the final project deliverables and project scope.

The Project Sponsor is responsible for formally accepting the project’s final deliverable. This acceptance will be based on a review of all project documentation.

SCHEDULE MANAGEMENT PLAN

Schedule management for the ***CVR Enhancements Project*** will be the sole responsibility of the Project Manager and is defined in the Milestones List.

Proposed schedule changes may be initiated by the Project Manager, Stakeholders or any member of the project team. All change requests will be submitted to the Project Manager who will then evaluate the request schedule change. Upon acceptance of the schedule change request the Project Manager will submit the schedule change to the Project Sponsor for acceptance. Upon approval of schedule changes by the Project Sponsor the Project Manager will update all project documents and communicate the schedule change to all stakeholders. Based on feedback and input from the Project Manager and Stakeholders, the Project Sponsor is responsible for the acceptance of the final project schedule.

STAFFING MANAGEMENT PLAN

The ***CVR Enhancements Project*** will consist of a matrix structure with support from various internal organizations. All work will be performed internally. Staffing requirements for the project include the following:

Project Manager (1 position) – Responsible for all management for the ***CVR Enhancements Project.*** The Project Manager is responsible for planning, creating, and/or managing all work activities, variances, tracking, reporting, communication, staffing, and internal coordination with functional managers as well as serve as technical lead for the project. The Project Manager will produce the final report for this project.

> The Project Manager will negotiate with all necessary functional leaders in order to identify and assign resources for the ***CVR Enhancements Project***. All resources must be approved by the appropriate functional leader before the resource may begin any project work. The project team will not be co-located for this project and all resources will remain in their current workspace.

T&D Planning Senior Engineer (1 position) – Responsible for technical leadership of CVR Enhancements Project team. The T&D Planning Senior Engineer will develop all technical documents as well as lead all tasks in the project.

EMS Leader or Designate (1 position) – Responsible for analyzing and programming LTC tap changer controller interface to SCADA system. Will also assist in determining programmatic control procedures for final CVR program.

Load Research Analysis (1 position) – Responsible for assisting in choosing which feeders should be analyzed to determine CVR effectiveness. Also responsible for determining methodology used in analyzing feeders for CVR effectiveness.

T&D Reliability Engineer (1 Position) – Responsible for assisting team in determining locations for new line devices associated with CVR enhancements.

Regional Operations Support Engineer (metering) (1 Position) – Responsible for assisting team in determining expanded uses of AMI system as it concerns CVR.

T&D Regional Planning Engineer (1 Position) **-** Responsible for assisting the T&D Planning Senior Engineer as required. The T&D Regional Planning Engineer will help develop test plans and assist in analysis work.

Regional Operations Line Crew (Multiple Positions) – Responsible for installing line equipment and metering devices associated with CVR Enhancements Project.

Stations Apparatus Engineer (1 Position) – Responsible for determining transformer LTC operational limits and also for design work associated with any new transformer LTC controls that may be applied as part of the CVR Enhancement Project.

System Protection Engineer (1 Position) – Responsible for assisting the team in design and procurement of feeder protective relaying that may be used in the project.

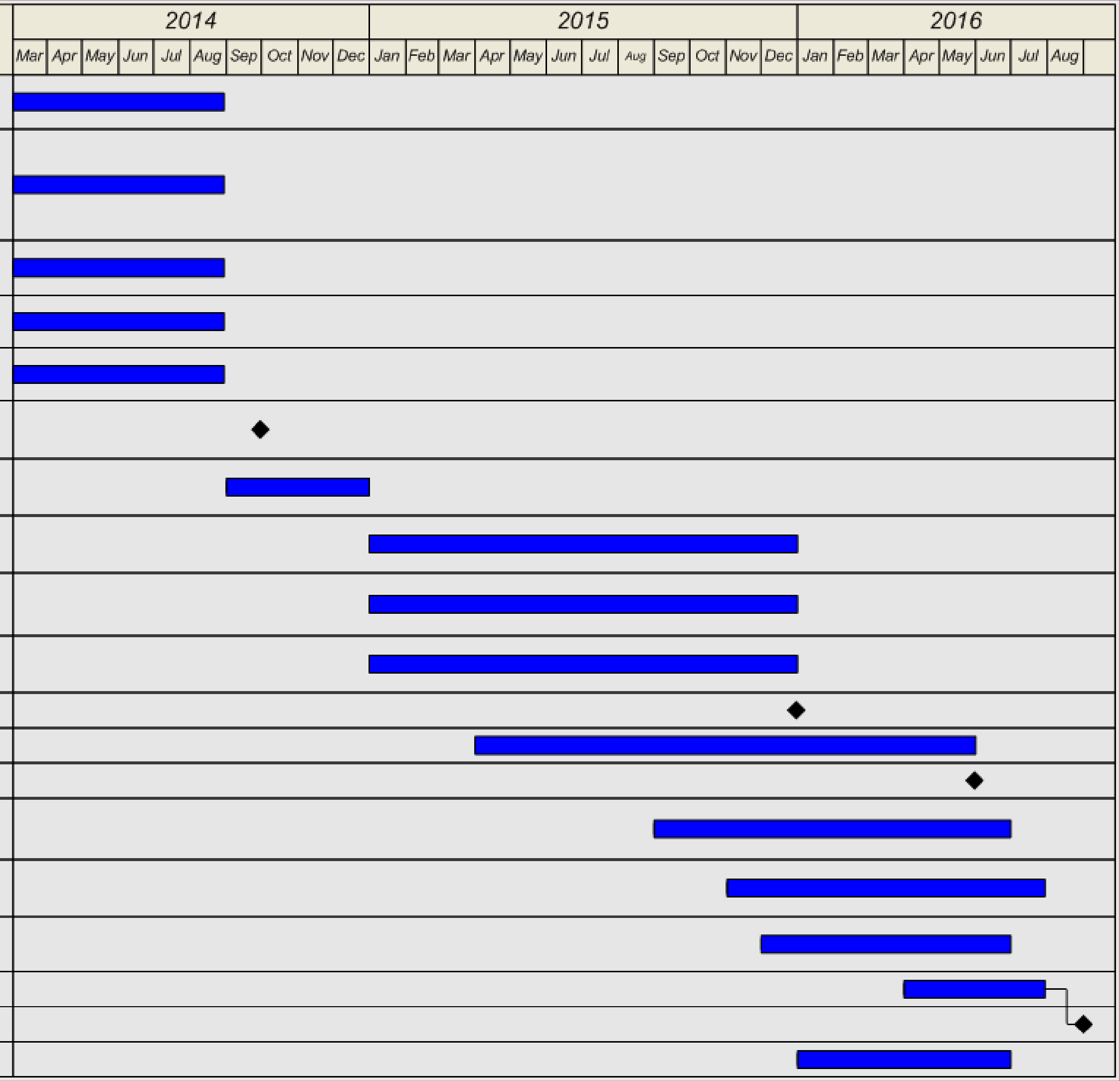
Power Quality, Senior Engineer (1 Position) – Responsible for analyzing power quality issues that may arise for devices installed as part of project. Will also assist in evaluating devices used in enhancing CVR.

COST BASELINE

This section contains the cost baseline for the project upon which cost management will be based. The cost baseline for the ***CVR Enhancements Project*** includes all budgeted costs for the successful completion of the project. Costs are still being estimated as of 9/8/14.

PROJECT SCHEDULE AND KEY MILESTONES

ID	Task Name	Start	Finish	Duration
1	Task 1: Develop Existing CVR Program Report	3/3/2014	8/29/2014	26w
2	Task 2: Develop method(s) to calculate CVR factors as a function of time, geographical location, and dominant customer type	3/3/2014	8/29/2014	26w
3	Task 3: Develop method(s) to analyze savings from CVR	3/3/2014	8/29/2014	26w
4	Task 4: Develop method(s) to capture CVR savings	3/3/2014	8/29/2014	26w
5	Task 5: Evaluate and select method to enhance CVR cost effectiveness	3/3/2014	8/29/2014	26w
6	**Place purchase order for data collection and pilot devices**	9/30/2014	9/30/2014	0w
7	Task 6: Make preparations to collect data on selected CVR Customer Grps	9/1/2014	12/31/2014	17.6w
8	Task 7: Collect Data on Customer Grps associated with Task 2.0	1/1/2015	12/31/2015	52.2w
9	Task 8: Collect Data on Customer Grps associated with Task 3.0	1/1/2015	12/31/2015	52.2w
10	Task 9: Collect Data on Customer Grps associated with Task Task 4.0	1/1/2015	12/31/2015	52.2w
11	**Complete Data Collection**	12/31/2015	12/31/2015	0w
12	Task 10: Analyze CVR Data	4/1/2015	5/31/2016	61w
13	**Complete Cos/Benefit Analysis**	5/31/2016	5/31/2016	0w
14	Task 11: Define Final CVR Program Structure and Layout	9/1/2015	6/30/2016	43.6w
15	Task 12: Determine CVR Program Rollout	11/2/2015	7/29/2016	39w
16	Task 13: Write Operating Procedures Manual	12/1/2015	6/30/2016	30.6w
17	Task 14: Write Report	4/1/2016	7/29/2016	17.2w
18	**Publish Final Report**	9/1/2016	9/1/2016	0w
19	Task 15: Remove Pilot Equipment	1/1/2016	6/30/2016	26w



SPONSOR ACCEPTANCE

Approved by the Project Sponsor:

____________________________________ Date: ________________

Daniel Arjona
Leader, T&D Planning

IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix H

ENGO Static VAR Device Pilot Project Plan

Delivery Planning
Research, Development an d Deployment

ENGO Static VAR Device Pilot Project
Project Plan

Date
12/24/2013
Revised 5/19/2014

TABLE OF CONTENTS

INTRODUCTION

Varentec's Edge of Network Grid Optimization (ENGO) unit is a solid state (static) VAR compensation device that provides dynamic or variable voltage control at the secondary side of distribution service transformers. The first ENGO unit is the single phase V10 which provides 10 kVAR of reactive support in steps of 1 kVAR, meaning the units can operate between 0 and 10 kVAR. A second unit, to be released in mid to late 2014, will provide 30 kVAR of reactive support and will be a three phase unit. This unit will be the V30 and is also intended for the secondary side of the service transformer. Varentec developed ENGO using DOE and ARPA-e funding as well as significant venture capital funding. These units have been deployed in pilot projects by a number of utilities and Varentec believes they are ready for commercialization, though still offering them in pilot quantities only.

This pilot project will deploy a number of ENGO units, both V10 and V30, to evaluate their viability for voltage support on feeders with spot voltage problems with the intent to use ENGO units in place of more expensive solutions such as reconductoring or small voltage regulators. The ENGO units may also be piloted on feeders presently involved in the Conservation Voltage Reduction (CVR) program where a more dynamic or aggressive voltage setting is desired. Additionally, the evaluation will include determining what, if any, affect the ENGO units have on Idaho Power's TWACS communications signal used by our AMI system.

The end product will be a report describing the testing performed and the results obtained from this pilot project. It is hoped that the units deployed in this project will remain in-place and will provide long-term voltage support.

PROJECT MANAGEMENT APPROACH

The Project Manager has the overall authority and responsibility for managing and executing this project according to this Project Plan. The project team will consist of personnel from the following departments: T&D Reliability Engineering, Regional Operations/Metering, T&D Planning, Power Quality, and others as appropriate. The Project Manager will work with all resources to perform project planning. All funding decisions will be made by the project sponsor.

The project team will be a matrix in that team members from each organization continue to report to their organizational management throughout the duration of the project. The Project Manager is responsible for communicating with organizational managers on the progress and performance of each project resource.

PROJECT SCOPE

The scope of ENGO Static VAR Device Pilot Project is to install, operate and test ENGO-V10 and ENGO-V30 solid state VAR compensating devices on various feeders on the Idaho Power system. The end product of this project will be a report that provides recommendations concerning ENGO use on the Idaho Power system for voltage support.

MILESTONE LIST

The chart below lists the major milestones for the ENGO Static VAR Device Pilot Project. This chart is comprised of major project milestones. If there are any scheduling delays which may impact a milestone or delivery date, the project manager must be notified immediately so proactive measures may be taken to mitigate slips in dates. Any approved changes to these milestones or dates will be communicated to the project team by the project manager.

Milestone	Description	Date
Purchase 25 ENGO-V10 units	Develop purchase order and place order for 25 ENGO-V10 units	12/31/2013
Determine Locations	Determine feeders and locations on feeders for ENGO unit installations	6/13/2014
Test Plan	Develop plan for installing, operating and testing ENGO units on Idaho Power system	4/30/2014
Install Units	Arrange for and perform installation of ENGO units	7/3/2014
Operate Units	Arrange for and perform operation of ENGO units	9/30/2014
Data Collection & Analysis	Collect and analyze data from ENGO units	11/14/2014
Remove ENGO Units	ENGO units will be removed upon project completion unless it is determined they are useful and should remain in-place	11/28/2014
Final Report		12/31/2014

WORK BREAKDOWN STRUCTURE

The WBS for the ENGO Static VAR Device Pilot Project is comprised of eight tasks as described below.

Task 1.0 – Purchase 25 ENGO-V10 units

1.1 Develop and place purchase order
1.2 Receive ENGO-V10 units
1.3 Varentec will be providing 6 ENGO-V30 units (30 kVAR, 3 phase) in late 2014 at no cost as part of a DOE funded initiative.
1.4 Pilot may expand to include additional ENGO units.

Task 2.0 – Determine Locations

2.1 Determine parameters to be used in deciding where units should be installed.
2.2 Determine feeders and locations on feeders for ENGO unit installations.
2.3 Prepare a spreadsheet that shows unit locations and operational parameters.

Task 3.0 – Test Plan

3.1 Develop test plan for installing, operating and testing ENGO units on Idaho Power system.
3.2 Test plan shall have buy-in from departments involved in the installation and operation of the ENGO units.
3.3 Test plan will be a separate document from Project Plan.

Task 4.0 – Install ENGO Units

4.1 Develop installation procedure for ENGO units.

4.1.1 ENGO-V10

4.1.2 ENGO-V30

4.2 Arrange for and perform installation of ENGO-V10 units. The initial order is for 25 ENGO-V10 units.

4.3 Arrange for and perform installation of ENGO-V30 units.

4.4 Installation will be complete prior to summer operating season.

Task 5.0 – Operate ENGO Units

5.1 Operations assignments to be determined.

Task 6.0 – Data Collection and Analysis

6.1 All data will be stored in common location.

6.2 Data will be provided by Varentec via their web-managed service.

6.3 Analysis will include:

6.3.1 Ability of ENGO units to maintain voltage setpoints under dynamic conditions.

6.3.2 Voltage profile of unit locations during summer operating conditions.

Task 7.0 – Remove ENGO Equipment

7.1.1 This task may be avoided if it is determined that the ENGO equipment should be left in-place.

Task 8.0 – Write Report

8.1 Issue final ENGO Static VAR Device Pilot Project report.

CHANGE MANAGEMENT PLAN

Any changes to either the scope or final scheduled delivery date for the ENGO Static VAR Device Pilot Project must be approved by the project sponsor: Manager of Delivery Planning. Project Manager may approve schedule changes that do not affect the final delivery date.

COMMUNICATIONS MANAGEMENT PLAN

This Communications Management Plan sets the communications framework for this project. It will serve as a guide for communications throughout the life of the project and will be updated as communication requirements change. This plan identifies and defines the roles of project team members as they pertain to communications. It also includes a communications matrix which maps the communication requirements of this project, and communication conduct for meetings and other forms of communication.

The Project Manager will take the lead role in ensuring effective communications on this project. The communications requirements are documented in the Communications Matrix below. The Communications Matrix will be used as the guide for what information to communicate, who is to do the communicating, when to communicate it, and to whom to communicate.

Communication Type	Description	Frequency	Format	Participants/ Distribution	Deliverable	Owner
Status Report	SharePoint summary of project status	Monthly	Share Point	RD&D Leader, Project Team and Stakeholders	Status Report	Project Manager
Project Meetings		As needed	In Person	Project Team	Meeting Minutes	Project Manager
Project Review	Present metrics and status to sponsor	Bimonthly	In Person	Project Sponsor	Status and Metric Presentation	Project Manager
Change Review	Review any Change Requests	As Needed	In Person	Project Sponsor and Project Team	Change	Project Manager

Communications Conduct:

Meetings:
The Project Manager will distribute a meeting agenda at least 2 days prior to any scheduled meeting. During all project meetings the Project Manager will ensure that the group adheres to the times stated in the agenda and the recorder will take all notes for distribution to the team upon completion of the meeting. Meeting minutes will be distributed no later than 3 working days after each meeting is completed.

PROCUREMENT MANAGEMENT PLAN

The Project Manager will work with the project team to identify all items or services to be procured for the successful completion of the project. Any procurement made as part of this project must be approved by the project sponsor.

PROJECT SCOPE MANAGEMENT PLAN

Scope management for the ENGO Static VAR Device Pilot Project will be the sole responsibility of the Project Manager. The scope for this project is defined by the Scope Statement and Work Breakdown Structure.

Proposed scope changes may be initiated by the Project Manager, Stakeholders or any member of the project team. All change requests will be submitted to the Project Manager who will then evaluate the requested scope change. Upon acceptance of the scope change request the Project Manager will submit the scope change request to the Project Sponsor for acceptance. Upon approval of scope changes by the Project Sponsor the Project Manager will update all project documents and communicate the scope change to all stakeholders. Based on feedback and input from the Project Manager and Stakeholders, the Project Sponsor is responsible for the acceptance of the final project deliverables and project scope.

The Project Sponsor is responsible for formally accepting the project’s final deliverable. This acceptance will be based on a review of all project documentation.

Schedule Management Plan

Schedule management for the ENGO Static VAR Device Pilot Project will be the sole responsibility of the Project Manager and is defined in the Milestones List.

Proposed schedule changes may be initiated by the Project Manager, Stakeholders or any member of the project team. All change requests will be submitted to the Project Manager who will then evaluate the request schedule change. Upon acceptance of the schedule change request the Project Manager will submit the schedule change to the Project Sponsor for acceptance. Upon approval of schedule changes by the Project Sponsor the Project Manager will update all project documents and communicate the schedule change to all stakeholders. Based on feedback and input from the Project Manager and Stakeholders, the Project Sponsor is responsible for the acceptance of the final project schedule.

Staffing Management Plan

The ENGO Static VAR Device Pilot Project will consist of a matrix structure with support from various internal organizations. All work will be performed internally. Staffing requirements for the project include the following:

Project Manager (1 position) – Responsible for all management for the ENGO Static VAR Device Pilot Project. The Project Manager is responsible for planning, creating, and/or managing all work activities, variances, tracking, reporting, communication, staffing, and internal coordination with functional managers as well as serve as technical lead for the project. The Project Manager will produce the final report for this project.

> The Project Manager will negotiate with all necessary functional leaders in order to identify and assign resources for the ENGO Static VAR Device Pilot Project. All resources must be approved by the appropriate functional leader before the resource may begin any project work. The project team will not be co-located for this project and all resources will remain in their current workspace. .

T&D Reliability Engineer (Multiple Positions) – Responsible for assisting the team in determining ENGO locations, test plan development, ENGO unit installation, ENGO unit operation, Data Collection & Analysis, and report writing. Specific duties will be determined as the project progresses. Individuals assigned these tasks will be determined by the region in which ENGO units are being installed.

Metering System Administrator (1 position) – Responsible for assisting the team in determining ENGO locations and test plan development.

Power Quality Engineer (Multiple Positions) – Responsible for assisting the team in determining ENGO locations, test plan development, ENGO unit installation, ENGO unit operation, Data Collection & Analysis, and report writing. Specific duties will be determined as the project progresses. Individuals assigned these tasks will be determined by the region in which ENGO units are being installed.

T&D Planning Senior Engineer (1 position) – Responsible for assisting the team in determining ENGO locations and test plan development. Will also assist in unit operation and data collection & analysis. Specific duties will be determined as the project progresses.

T&D Planning Engineer (Multiple Positions) **-** Responsible for assisting the team in determining ENGO locations. Will also assist in unit operation and data collection & analysis. Specific duties will be determined as the project progresses Individuals assigned these tasks will be determined by the region ENGO units are being installed.

Regional Operations Line Crew (Multiple Positions) – Responsible for installing ENGO units at locations designated by project team. Also responsible for removing and/or relocating units as directed by Project Manager. Individuals assigned these tasks will be determined by the region ENGO units are being installed.

Cost Baseline

This section contains the cost baseline for the project upon which cost management will be based. The cost baseline for ENGO Static VAR Device Pilot Project includes all budgeted costs for the successful completion of the project.

Tasl	Description	Hours	341 PM Hours	Load Researc	T&D Reliabili	Meterir	Power Qualit	T&D Plannir	Regional Operations Line Crev	Material	Notes
1.0	Purchase 25 ENGO-V10 Units	16	16							$28,740	
2.0	Determine Locations	160	40	40	24	8	16	32			
3.0	Develop Test Plan	68	40		8	4	8	8			
4.0	Install ENGO units - Pocatello	136	16		8		8		104	$1,500	Estimate 4 hours per unit (2 man crew = 8) including travel and setup. Material is bucket truck. 13 Units
	Install ENGO Units - Various	144	16		8		8		112	$2,000	Estimate 4 hours per unit (2 man crew = 8) including travel and setup. Material is bucket truck. 115 Units
5.0	Operate ENGO Units	64	24		16		16	8			
6.0	Data Collection and Analysis	136	80	8	16		16	16			
7.0	Write Report	96	80		8		8				
8.0	Remove ENGO Equipment	144	24						120	$2,000	Estimate 2 hours per unit including travel and setup
	Total Hours	964	336	48	88	12	80	64	336		
	Weeks	24.1	8.4	1.2	2.2	0.3	2	1.6	8.4		
	Days	120.5	42	6	11	1.5	10	8	42		
	Labor Cost/Hour		$60	$53	$50	$50	$50	$50	$55		
	Total Labor Cost per function	$53,384	$20,160	$2,544	$4,400	$600	$4,000	$3,200	$18,480		
	Total Material Cost	$34,240								$34,240.00	
	10% Contingency	$8,762									
	Total Project Cost	$96,386									

PROJECT SCHEDULE

ID	Task Name	Start	Finish	Duration
1	Task 1: Purchase 25 ENGO-V10 Units	12/2/2013	12/13/2013	2w
2	Task 2: Determine ENGO Install Locations	1/28/2014	6/13/2014	19.8w
3	Task 3: Develop Test Plan	2/28/2014	4/30/2014	8.8w
4	Task 4: Install ENGO Units	6/16/2014	7/3/2014	2.8w
5	Task 5: Operate ENGO Units	7/1/2014	9/30/2014	13.2w
6	Task 6: Data Collection and Analysis	7/1/2014	11/14/2014	19.8w
7	Task 7: Remove ENGO Equipment	10/1/2014	11/28/2014	8.6w
8	Task 8: Write Report	11/3/2014	12/31/2014	8.6w
9	Publish Report	12/31/2014	12/31/2014	0w

Sponsor Acceptance

Approved by the Project Sponsor:

____ Date: ____________________

David Angell
Manager, Delivery Planning

IDAHO POWER COMPANY

2014 SMART GRID REPORT

Appendix I

Demand Response as Operating Reserves Feasibility Report

DEMAND RESPONSE
AS OPERATING RESERVES
FEASIBILITY REPORT

September 30, 2014

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EXECUTIVE SUMMARY

In Settlement Agreements filed in both Idaho and Oregon[1] and approved by the Idaho Public Utilities Commission ("IPUC") and the Public Utility Commission of Oregon ("OPUC") in Order Nos. 32923 and 13-482, respectively, Idaho Power Company ("Idaho Power" or "Company") agreed to investigate the feasibility of using Demand Response ("DR") as operating reserves and to make a determination on the feasibility by the end of the 3rd quarter of 2014.

The Demand Response as Operating Reserves Feasibility Report ("Report") provides a background of the Company's operating reserves requirements, and identifies that DR could only be used for the non-spinning portion of the Company's Contingency Reserves Obligation ("CRO"). It describes each of the DR programs the Company currently operates, discusses the applicability of using DR as CRO from a compliance perspective, and describes the implementation requirements for the Company to use its DR programs as CRO. The Report then examines each of the DR programs and discusses whether or not each one has potential to be used as CRO. The Report concludes with the Company's financial analysis and recommendation.

Based on its analysis, Idaho Power concluded the risks outweigh the benefits to utilize DR as CRO because: (1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and provide for program costs, (2) the risks for failure to meet North American Electric Reliability Corporation ("NERC") standards is far greater than the economic benefit that might be derived, (3) the period of testing that would be required to provide operational certainty of compliance with NERC and Western Electricity Coordinating Council ("WECC") requirements would require carrying substantially more than the reserves actually needed for contingency, at a cost to all customers, and (4) the number of CRO events would put too heavy of a strain on the DR participants, thus risking participation in the Company's DR programs.

As described in the Report, the economic benefit, excluding payments to participants and program costs, of using DR as CRO is insignificant when compared to the capacity benefit the current DR programs provide. While having a dual-purposed program may be conceivable from a technical and compliance perspective, the Company believes that it is not practical from an economic and DR program participant perspective. The Company believes that the economic, DR program participation and other operational risks identified in this Report, are too great to proceed with a pilot at this time.

[1] Idaho Case No. IPC-E-13-14 and Oregon Case No. UM-1653.

Introduction

In late 2012 and early 2013, Idaho Power filed for changes to its A/C Cool Credit program, Irrigation Peak Rewards program, and FlexPeak Management program (collectively "DR Programs") in both its Idaho and Oregon jurisdictions.[2] These filings were prompted by the lack of near-term peak-hour deficits identified in the Peak Load and Resource Balance analysis prepared for the 2013 Integrated Resource Plan ("IRP"), and Idaho Power's desire to take prompt and prudent steps to avoid some of the expenses associated with the programs in years where the Peak Load and Resource Balance analysis did not show a need.

In Order No. 32823, the IPUC opened Case No. IPC-E-13-14, and set an informal prehearing conference to be held on June 12, 2013, to schedule workshops to evaluate Idaho Power's DR Programs for the 2014 program season and beyond. The IPUC ordered that the Idaho Irrigation Pumpers Association ("IIPA"), the Idaho Conservation League ("ICL"), and the Snake River Alliance ("SRA") were designated as intervening parties in this case. Additional petitions to intervene in this proceeding were filed by the Industrial Customers of Idaho Power ("ICIP") and EnerNOC, Inc. ("EnerNOC").

In the interest of administrative efficiency for the OPUC and for the Oregon customers of Idaho Power, in May of 2013, the OPUC opened Docket No. UM 1653 to facilitate participation by OPUC Staff and interested Oregon parties in the Idaho workshop process.

Following the June 12, 2013, prehearing conference, the parties set a schedule for four workshops, which were held on July 10, July 23, August 7, and August 19. During the August 19 workshop, the participants agreed to hold an additional workshop on August 27, 2013, which included confidential settlement discussions. An additional workshop was held in Oregon for the benefit of interested Oregon parties on October 9, 2013, where the results of the prior workshops were reviewed, questions were answered, and parties held settlement discussions.

Based upon the Idaho proceedings, several parties, including Idaho Power, IPUC Staff, IIPA, ICL, SRA, EnerNOC, and non-party customer Mike Seaman agreed to resolve and settle issues related to the reinstatement of Idaho Power's DR Programs for 2014 and beyond. The signed Settlement Agreement was approved by the IPUC in Order No. 32923. The Company filed a similar Settlement Agreement with the OPUC in Docket No. UM 1653, which was approved by Order No. 13-482. Both Settlement Agreements are working as envisioned and during the 2014 DR program season the Company had enrolled DR participants to provide approximately 390 megawatts ("MW") of maximum load reduction at generation level, which is near prior levels of DR capacity before the programs were temporarily suspended in 2013.

[2] Idaho Docket Nos. IPC-E-12-29, IPC-E-13-04, Oregon Advice 13-04 and Docket No. UM-1653.

In these Settlement Agreements, Idaho Power agreed to investigate the feasibility of using DR as operating reserves and make a determination on the feasibility by the end of the 3rd quarter of 2014.[3]

This Report presents the Company's feasibility review and recommendation not to use DR as operating reserves. First, the Report will provide a regulatory and operational overview of the Company's operating reserves requirements and will then describe each of the DR Programs the Company currently operates. The Report will then discuss the applicability of using DR as operating reserves from a compliance perspective and describe the implementation requirements for the Company to use its DR Programs as operating reserves. The Report will then examine each of the DR Programs and discuss why the DR Programs should not be used as operating reserves.

Regulatory and Operational Overview

For operation of its Bulk Electric System ("BES"), Idaho Power is regulated by the Federal Energy Regulatory Commission ("FERC") who oversees the NERC, as the Electric Reliability Organization ("ERO") for North America, a requirement of the Federal Power Act of 2006. NERC is the entity that develops and enforces the mandatory Reliability Standards that Idaho Power must adhere to, governed by Section 215 of the Federal Power Act. In addition to adhering to NERC Standards, Idaho Power is a member of the WECC, the Regional Entity responsible for coordinating and promoting BES reliability in the Western Interconnection.

Operating Reserves

NERC and WECC standards require that the Company hold a certain amount of operating reserves to ensure reliable operation of the system. NERC defines operating reserves as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection,"[4] or simply, the generation capacity required above the Company's load for possible contingency events, changes in load, and accommodation for variable generation. Operating reserves are comprised of Contingency Reserve[5] Obligations ("CRO") and Regulating Reserves.[6]

CRO is the amount of generation capacity generally held for use for events such as generator trips resulting in loss of generation or transmission line trips resulting in loss of import energy, while Regulating Reserve is the unloaded generation capacity

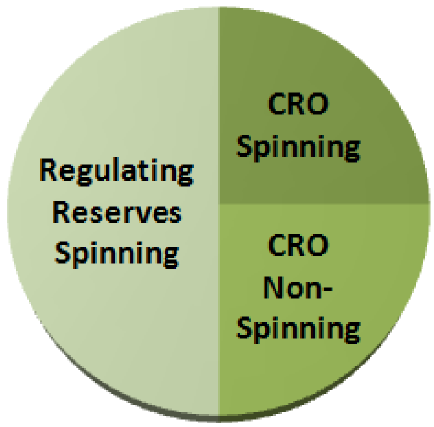
[3] Demand Response Programs Settlement Agreement at 4.

[4] NERC's Glossary of Terms Used in NERC Reliability Standards: http://www.nerc.com/files/glossary_of_terms.pdf

[5] NERC defines Contingency Reserve as "the provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements." *Id*.

[6] NERC defines Regulating Reserve as "an amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin." *Id*.

generally used for moment to moment changes in both load and variable generation. Typically the Company's CRO must have at least 50 percent met by Spinning Reserves,[7] with the remaining met with Non-Spinning Reserves[8] while Regulating Reserves are comprised completely of Spinning Reserves. Spinning Reserves is unloaded generation capacity that is online and synchronized to the electrical system while Non-Spinning Reserves is generation or load that can be dispatched and utilized within 10 minutes.[9]



In terms of managing and maintaining its operating reserves, Idaho Power is required to adhere to the following NERC and WECC standards: the Real Power Balancing Control Standard (BAL-001), the Disturbance Control Performance Standard (BAL-002), the Frequency Response and Frequency Bias Setting Standard (BAL-003), the Contingency Reserve Standard (BAL-002-WECC-2), and the Northwest Power Pool Reserve Sharing Agreement. Ultimately, Idaho Power must be able to meet the Most Severe Single Contingency ("MSSC") (BAL-002) with CRO, which for Idaho Power is 330 MWs, and equivalent to the loss of two units at the Jim Bridger Power Plant.

Because DR is not generation, it can only be used to satisfy the non-spinning portion of the Company's CRO, and as such, the remainder of this Report will focus on the CRO rather than total operating reserves, which are comprised of both CRO and Regulating Reserves.

CRO at Idaho Power

Generally, the Company's CRO is met by utilizing hydro generators that have reservoir storage available to provide the rapid response for the extended time needed, but other

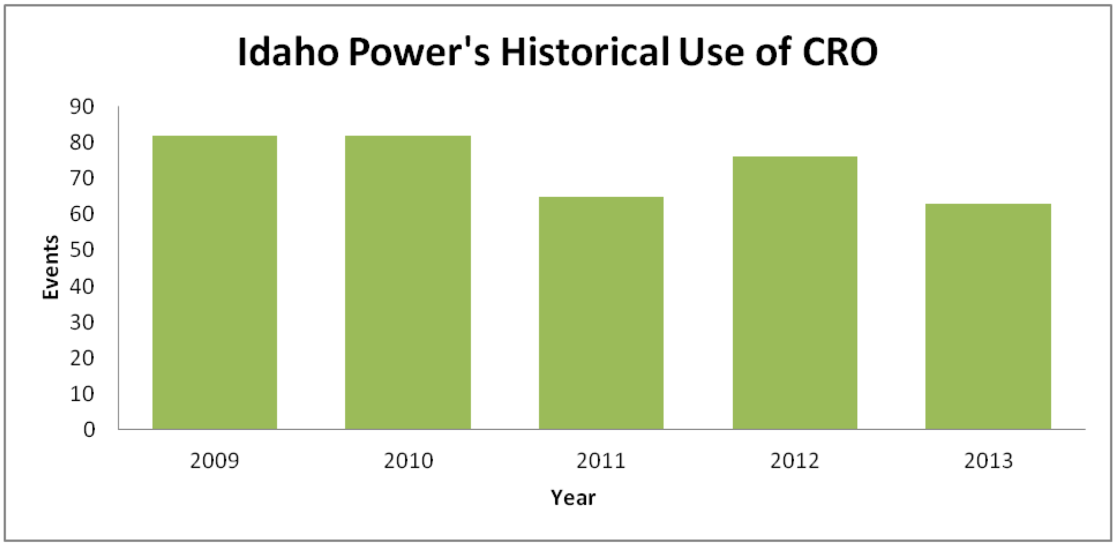
[7] NERC defines Spinning Reserve as "unloaded generation that is synchronized and ready to serve additional demand." *Id*.

[8] NERC defines Non-Spinning Reserve as "that generating reserve not connected to the system but capable of serving demand within a specified time" or "interruptible load that can be removed from the system in a specified time." *Id*.

[9] The 10 minute requirement is mandated by the Reserve Sharing Agreement Idaho Power adheres to as a member of the Northwest Power Pool.

types of generation used for reserves include the Company's thermal fleet that has demonstrated the ability to respond within the 10 minute timeframe. When used as reserves, these hydro or thermal plants have their generation output reduced and held in reserve to provide the capacity that can be activated when needed.

The number of times Idaho Power uses its CRO varies widely and is not predictable by day, duration, or number of MWs. The Company called on its CRO 82, 82, 65, 76, and 63 times during the years 2009 through 2013, respectively. The events spanned all seven days of the week, all 12 months of the year, and the number of MWs called on ranged from as few as two to as many as 171 during a single event. The chart below demonstrates how many times over the prior five years Idaho Power has called on its CRO.



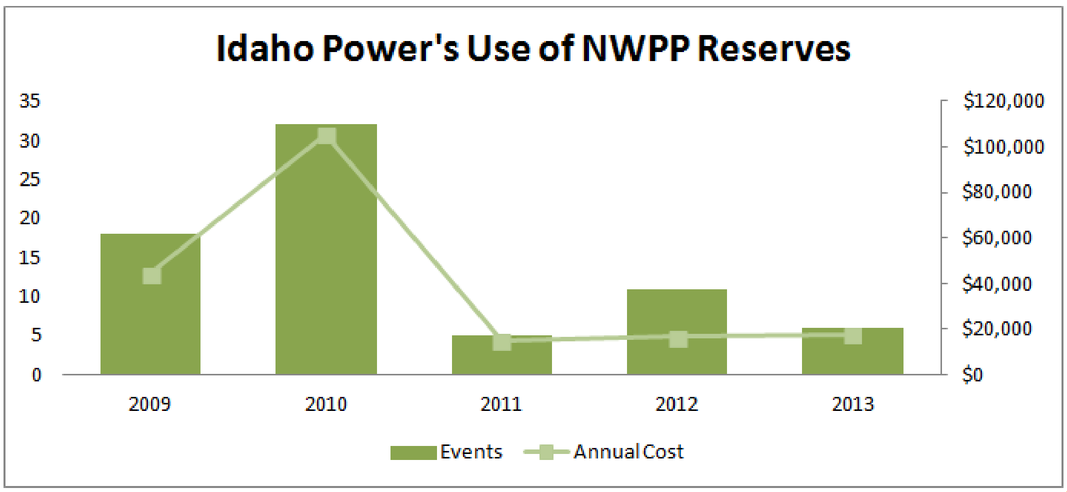
Northwest Power Pool

In addition to utilizing its own resources to meet its CRO, Idaho Power is a member of the Northwest Power Pool ("NWPP"), which is registered with WECC as a Reserve Sharing Group ("RSG") for compliance with the NERC Standard BAL-002 and the WECC Regional Standard BAL-002-WECC-2. By participating in the NWPP RSG, Idaho Power is able to reduce its overall Company-held CRO requirement to approximately half of its 330 MW MSSC.[10] As a member of a RSG, Idaho Power can utilize the reserves of other members in the event that it has exhausted its CRO. Conversely, other RSG members can request Idaho Power to deliver its CRO to assist in the mitigation of contingency events. The energy requested by the other NWPP members may not exceed Idaho Power's CRO. The operating agreements of the NWPP RSG allow for the real-time sharing of energy assistance without prior transmission reservations or payment for reserved generation capacity.

[10] Idaho Power's CRO is determined based on the following formula: CRO = (5% * Hydro Generation) + (7% * Thermal Generation). For the most recent 12 month period, the average CRO held was 113 MW.

NWPP RSG participants, like Idaho Power, differ from those entities that are bidding into an organized market for energy and capacity because the ability to call on the NWPP RSG allows the Company to reduce the amount of reserves it holds as capacity. Conversely, entities who operate in a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") market bid into that market based on each utility's relative costs of energy *and* capacity, and the market determines which resources are utilized to supply the needs of the entire RTO/ISO balancing area. Those costs are then spread across all participants in that balancing area.

The Company called on the NWPP RSG reserves 18, 32, 5, 11, and 6 times during the years 2009 through 2013, respectively. The events spanned all seven days of the week, all 12 months of the year, and the number of megawatt-hours called ranged from as few as one to as many as 599 during a single event. The chart below demonstrates how many times over the prior five years Idaho Power has called on the NWPP RSG (primary axis), and the annual dollars spent for all events (secondary axis). In the event that Idaho Power utilizes the NWPP RSG, it pays for that energy based on a market value[11] at the time of an event, so the Company is only paying for the market value of the energy and is not paying to reserve generation capacity or for transmission.



Demand Response Programs at Idaho Power

Idaho Power has three DR programs available for and tailored to each of its Residential, Large Commercial & Industrial ("C&I"), and Irrigation customer classes.

A/C Cool Credit is a voluntary DR program available to the Company's residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners ("A/C") or heat pumps off and on via a direct-load control device installed on the units. The program is available during summer peak

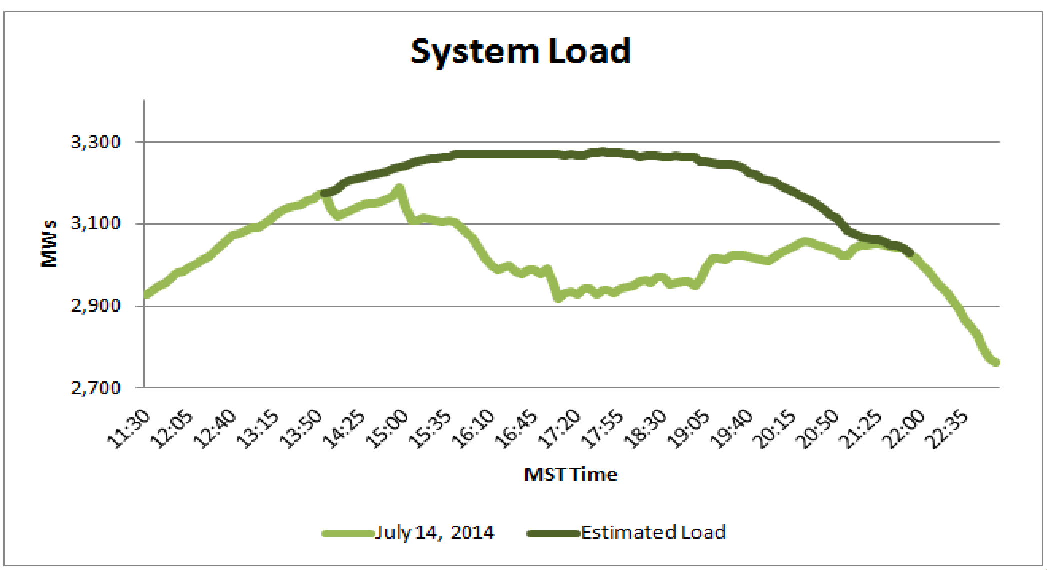
[11] For purposes of the Reserve Sharing Program, the settlement price will be the average of the Powerdex Mid-Columbia hourly price for (1) the hour during which the participant first requests Assistance Reserve (the "Request Hour") and (2) each of the two hours immediately following the Request Hour; provided, however, that in no event will the settlement price be less than zero or greater than the price cap in effect for the WECC in accordance with regulations and orders of FERC in effect as of the Request Hour.

periods between June 15 through August 15 with maximum event durations of four hours, and maximum event hours during the season of 60.

FlexPeak Management is a voluntary DR program available to the Company's C&I customers capable of reducing their electrical energy consumption for short periods of time. The program is administered by Idaho Power through a third-party aggregator and relies on customers voluntarily reducing use at their sites when they are notified of an event. The program is available during summer peak periods between June 15 through August 15 with maximum event durations of four hours, maximum event hours during a season of 60, and the maximum number of events called during a season of 20.

Irrigation Peak Rewards is a voluntary DR program that is available to the Company's agricultural irrigation customers. The program pays irrigation customers a financial incentive for the ability to turn off participating irrigation pumps at potential high system demand periods. The program is available during summer peak periods between June 15 through August 15 with maximum event durations of four hours, maximum event hours during a calendar week of 15, and maximum event hours during a season of 60. Irrigation Peak Rewards has three options for customer participation: two that are dispatched via direct-load control devices and a third manual interruption option that does not utilize a direct-load control device, but rather relies on participants to manually interrupt their loads when notified of an event.

During the 2014 season, Idaho Power's DR Programs were all utilized, with each program being dispatched three times. The chart below represents the estimated demand reduction achieved on July 14, 2014, when all three programs were dispatched on the same day. The nighttime and daytime temperatures that day were 73 and 103 degrees, respectively. The estimated reduction was based on real-time forecasting of the system loads, and based on that estimate, the DR Programs provided approximately 375 MW of peak load reduction.



Applicability

Idaho Power's research indicates that NERC and WECC standards would allow the use of DR as a non-spinning reserve. In order to be compliant with the standards, Idaho Power must ensure that it is able to: (1) accurately measure the amount of reserves claimed, (2) guarantee all reserves are activated within 10 minutes, and (3) maintain documentation to be provided during a NERC/WECC audit.

In order to ensure that the DR resource would perform as required when dispatched to provide CRO, the Company would require that a program be designed and implemented for a two-year period in order to ensure that the amount of CRO expected to be provided by the DR resource can be achieved 100 percent of the time in the required timeframes. The Company believes that for it to be able to depend on DR to provide all or a portion of CRO when needed, sufficient testing must be done to ensure deliverability of the load reduction that DR would provide under various system conditions. As noted earlier, the average CRO required by Idaho Power over the most recent 12 months was 113 MW, and for the Company to understand how it could use DR to meet a portion of that requirement, it would need to gain enough data during that two-year period to determine how much DR it could confidently integrate into the overall CRO requirement.

Further, to ensure compliance with the above-mentioned standards, if it were to use DR as part of its CRO, Idaho Power would require that its Real-Time Operators ("Operators") will have direct control over the resource. As system events occur, the Operators are evaluating system conditions to determine the appropriate action to take, and as the Operators execute these actions they are re-evaluating in real-time to ensure that the expected results are accomplished. By having direct-load control over the resource, the Operators can ensure that the expected load response occurs in time to comply with the NERC regulations, and in the event the expected load response does not occur, the Operator will immediately take additional actions to comply with the regulations. All of the Operators' actions are critical to maintaining the reliability of the electrical grid, and most importantly, all must be executed within a 10 minute period.

Lastly, Idaho Power is required to maintain auditable documentation to be provided to NERC/WECC, as requested at any time. At a minimum of once every three years, audits of this documentation are conducted by WECC, NERC, and occasionally FERC.

Implementation Considerations

Based on the requirements discussed earlier, the Company evaluated its current operations, systems and limitations to identify what modifications would need to be made to use DR as CRO. The Company also analyzed each of its three DR programs to determine the ability to use each as CRO and whether or not that program was a possible "fit" for providing CRO. In considering each program, the Company looked at several factors, including: whether or not there was a direct-load control device installed as a requirement of the DR program, the ease or difficulty of forecasting the demand reduction achieved by the program, the number of hours/days the DR program would be available as CRO, the size of the DR program in MWs and number of participants, and program participant notification requirements.

Operation System Modifications

The Company's existing Load Serving Operations' ("LSO") systems would need to undergo significant upgrades to be able to incorporate the use of DR as CRO. These upgrades include integration of the dispatch system(s) for each program to the Energy Management System ("EMS") and development of a fully integrated DR forecasting tool.

The EMS network consists of one or more control centers and Supervisory Control and Data Acquisition ("SCADA") connections to many field locations, typically substations. Field equipment takes measurements and sends data back to the control center to provide situational awareness to Operators. Those Operators have the ability to control field equipment through the SCADA network. Because the current EMS is not integrated with the other communication systems necessary to dispatch any DR resource, modifications would be required. In order to respond within the required 10 minute period, the Operator needs a specific tool that presents the forecasted load for any DR providing CRO. The current forecasting tools for all three of the Company's DR programs do not provide day ahead or real-time components, only a weekly generalized forecast. System modifications would be required to ensure that the forecast of DR on the system is being constantly updated with the most current data available. The updated systems would need to be able to quickly determine how much load reduction is achieved from DR and to continually update the forecast that the Operators are relying on for optimum accuracy.

A/C Cool Credit

The A/C Cool Credit program provides approximately 33 MW of load reduction if dispatched when temperatures are near 100 degrees throughout the program's season of June 15 through August 15. The program requires the installation of direct-load control devices as a provision of participation, which means the Company could utilize existing infrastructure if it determined the program was viable to use as CRO. The program currently uses one system to dispatch all events, so any necessary LSO system modifications would only require integration with that one system.

The current program cycles A/C units off and on between June 15 and August 15, but the Company believes that its A/C load could only provide substantial and reliable load reduction during certain hours of certain days during that time period. The program season could be expanded, but likely would not provide very much benefit due to the reduced A/C load during much of the summer.

There are many factors that influence the amount of load reduction the Company may experience during an event, including the temperature on the day of the event, the daytime and nighttime temperatures of the days leading up to the event, the time of day the event is called, and the amount of cycling (percent of time the unit is off) that is utilized. Generally, the Company would anticipate receiving about one kilowatt ("kW") per participant on a 100 degree or higher day, so long as those A/C units were on at the time of the event. Based on these factors, the amount of load available for CRO from the A/C Cool Credit program would be small and would vary dramatically hour by hour and day by day.

In addition, because customers have the ability to “opt out” of a single event, or the entire program at anytime, the Company and its contractor must be staffed during events to receive participant inquiries. Extending the program for its use as CRO would likely increase the labor costs of the program because the program could be called as CRO outside of normal business hours when the Company and its contractor currently do not have adequate staff available.

FlexPeak Management

The FlexPeak Management program provides approximately 38 MW of load reduction during events called throughout the program’s season of June 15 through August 15. While the third-party aggregator does have a handful of sites where there are direct-load control devices installed, most customers are in control of curtailing their own load at a participating site, and Idaho Power does not have direct control over any of the devices. For this reason, it is not feasible to consider the FlexPeak Management program for use as CRO, due to the requirement that Operators have direct control over the resource and that the resource must be fully dispatched within 10 minutes of an event starting.

Irrigation Peak Rewards

The Irrigation Peak Rewards program provides approximately 319 MW of load reduction during events called throughout the program’s season of June 15 through August 15. Irrigation Peak Rewards has three options for customer participation: two that are dispatched via direct-load control devices (approximately 240 MW) and a third manual interruption option that does not utilize a direct-load control device, but relies on participants to manually interrupt their loads (approximately 60 MW).

The program is currently structured to be used between June 15 and August 15, but the Company believes that its irrigation load could provide potential load reduction from mid-April through the end of September. Irrigation load typically runs at all hours of the day, so the Company believes that logistically, it is reasonable to expect Irrigation Peak Rewards could provide some level of CRO at most all hours of the day during the identified time period, (although this is difficult to predict based on the unpredictability of weather and the variability of crop characteristics). The Company believes it would be complicated to forecast the irrigation load available in the program for CRO each hour of each day throughout the irrigation season, but with modifications to the existing systems it could be done.

Lastly, because the Company would require that direct-load control devices are used to curtail load, only the first two options would be viable for consideration of the program as CRO. Based on current participation in the program, these two resources have the ability to provide approximately 240 MW of load curtailment.

Evaluating DR as a CRO

Costs

In order to provide Operators with a tool to effectively and reliably use DR as CRO, several modifications to the Company's existing technological infrastructure would be required. The current system configuration is not set up to directly dispatch DR in the timeframe necessary. The system modifications described below would enable the Operators to dispatch the DR resource within 10 minutes, as required by the WECC Reliability Standard BAL-002-WECC. The current system would also require a fully integrated real-time forecasting component necessary to assist the Operators in accurately determining the expected hourly DR load reduction.

- Modify the existing EMS to ensure the capability to dispatch the DR resources, providing visibility to Operators of available DR resources and with the ability to easily dispatch those resources in a timely manner. *Estimated Cost:* *<u>$50,000</u>*
- Develop or procure an application that accurately forecasts on an hourly basis the currently available DR on the Idaho Power system. *Estimated Cost:* *<u>$300,000</u>*
- Develop or procure an application that receives the request to dispatch DR resources and determines the specific points of service to curtail. *Estimated Cost:* *<u>$75,000</u>*
- Develop an application to enable the rapid and reliable dispatch of the appropriate DR resources. Currently, the systems used to dispatch DR reside on different networks and utilize different databases/data structures. The Company would need to ensure that information will be passed both securely and reliably between these systems. *Estimated Cost:* *$<u>50,000</u>*

Based on the required modifications, the total minimum upfront cost is estimated to be *$475,000;* however, the cost associated with the forecasting application could be higher depending on the specific DR programs that are selected. In addition to the upfront costs, there would be ongoing, annual costs associated with maintaining the upgraded and new systems. The annual cost associated with software maintenance and support is estimated to be $95,000, based on similar technology system projects that Idaho Power has completed and currently maintains.
It is expected that the life of the application will be approximately eight years before technology changes would require that it would have to be replaced or upgraded. It is projected that the cost of replacement or upgrade in eight years will be $150,000.

The projected timeline for implementing the modifications outlined above would be approximately six months to a year. This timeframe would provide for the ability to develop and verify the forecast, as well as providing adequate time to develop, test, and implement the other applications and integrations.

As discussed in the Applicability section above, in order to ensure that the DR resource would perform as required when dispatched to provide CRO, the Company would require that a program be designed and implemented for a two-year period of testing. Because Idaho Power would continue to utilize the resources that it currently uses to provide CRO during this testing period, the benefits of making these reserves available does not occur until the third year.

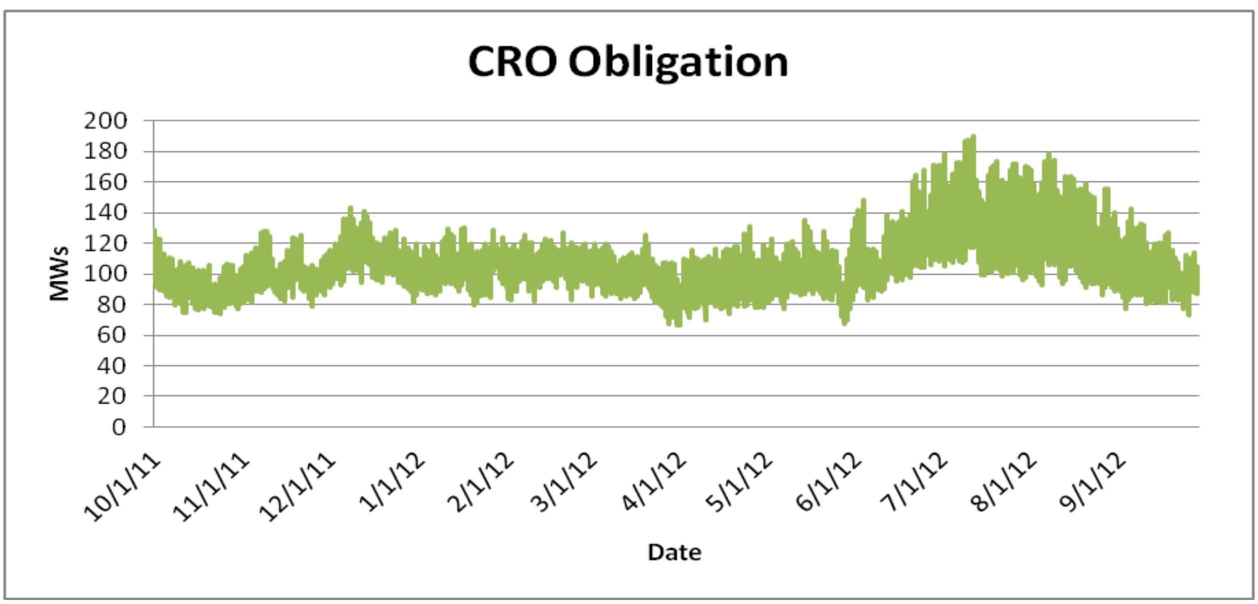
Benefits

To identify the potential benefits associated with using DR as CRO, the Company performed an analysis to quantify the dollar value of its CRO. The Company assumed levels observed during the 2012 Water Year (October 2011 through September 2012) for multiple system parameters, including system load, Mid-C prices, and natural gas prices. Water Year 2012 was selected for these parameters because the Snake River basin observed median-type stream flow conditions during Water Year 2012. Based on those assumptions, the Company conducted a study to determine the maximum dollar value of its CRO during a time period that DR could conceivably provide CRO. The time period utilized in the study assumes that DR could be available from mid-April through the end of September and valued the CRO during this time period at three different levels:

Results:

- Value of all of the non-spinning reserves. *Estimated Value: $578,212*
- Value of half of the non-spinning reserves. *Estimated Value: $363,678*
- Value of all of the heavy load hours non-spinning reserves (Monday through Saturday, 7 AM through 11 PM) *Estimated Value: $518,979*

The following chart represents the Company's total CRO during the time period studied. The maximum non-spinning portion of CRO identified by the Company's analysis was 96 MW.



Financial Analysis

The Company used the costs and benefits identified above to calculate an estimated annual levelized benefit and net present value of using DR as CRO. The annual levelized benefit amount is what the Company believes is the maximum incremental amount it could incur on an annual basis to use DR as CRO (for example to pay program incentives to participants or for program expenses), without financially harming other customers. In other words, if the annual levelized benefit amount was input in the financial analysis as an annual expense, the resulting net present value would be zero. The Company analyzed two scenarios for the Irrigation Peak Rewards program and a third scenario for the A/C Cool Credit program, which are presented below.

Based on the financial analysis performed for this Report, if the Irrigation Peak Rewards program were to provide all of the non-spinning reserves required from mid-April through September 30th at a 90 percent availability level,[12] the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $385,900 on an annual levelized basis. If the Irrigation Peak Rewards program were to provide all of the non-spinning reserves required during only heavy load hours from mid-April through September 30th at a 90 percent availability level, the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $336,400 on an annual levelized basis.

A current participant in the Irrigation Peak Rewards program receives an annual incentive of approximately $16 per kW of demand, which includes three dispatch events per season. For dispatch events beyond the first three, participants receive an energy payment based on the amount of demand reduction they are expected to provide during each dispatch event. If the Company were to design a program to be used as CRO, it would propose paying participants only fixed payments. The fixed payment structure would ensure that the Company does not make payments exceeding the annual levelized benefit amount. Additionally, because the CRO program would have an unknown and potentially unlimited number of events, the Company believes it would be imprudent to structure a program with a variable payment that would have the potential to exceed total benefits.

Using the scenario above where Irrigation Peak Rewards provides all of the non-spinning reserves required from mid-April through September 30th at a 90 percent availability level, the maximum amount the Company could design a program for is $385,900 on an annual levelized basis. This program would seek to achieve up to 96 MW of CRO and translates to a maximum $3.00 per kW of potential incentive.[13] The

[12] The Company does not believe it is reasonable to expect the Irrigation Peak Reward or A/C Cool Credit programs could provide 100 percent of the Non-Spinning reserves during the time studied. Ninety percent was selected to account for times when the programs would not be available due to factors such as mild temperatures and consecutive days of rain that would significantly impact whether participants would have irrigation pumps or A/C units turned on.

[13] For purposes of this report, the Company did not estimate total program costs to run a new CRO program. The actual amount available for participant incentives would be net of any program expenses incurred.

Company does not believe its irrigation customers would participate in a program that would have unlimited dispatch events, during all hours of the day, for only 20 percent of the incentive that the current Irrigation Peak Rewards participants are receiving from the traditional DR program.

Similarly, based on the financial analysis performed for this Report, if the A/C Cool Credit program were to provide approximately 35 percent[14] of the non-spinning reserves required during only heavy load hours[15] from mid-April through September 30th at a 90 percent availability level, the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $54,600 on an annual levelized basis. Under the current A/C Cool Credit program design, a participant receives an incentive of $15 per season, for no more than 60 hours of potential A/C cycling. Using the calculated annual levelized value of $54,600, the maximum Idaho Power could offer a participant in a CRO program is approximately $1.80 per season.[16] Here again, the Company does not believe its residential A/C customers would participate in a program that would have unlimited dispatch events for only 12 percent of the incentive that the current A/C Cool Credit participants are receiving from the traditional DR program.

Risks

Company Risk

It is critical to Idaho Power and the reliability of the BES that any CRO it maintains will undoubtedly perform as expected when it is dispatched, and the risks associated with not having a resource perform as projected cannot be understated. In the event that CRO is not responsive when activated, the Company is exposed to FERC, NERC, and WECC compliance violations as well as BES reliability issues that could negatively impact the electrical interconnection.

Part of the Operators' responsibly is to maintain system reliability, which is accomplished by various methods including the ability to shed firm load. The reliability to all of Idaho Power's customers could be impacted if a CRO resource does not perform when dispatched because the Operator may be required to activate the Load Curtailment and Interruption Procedure,[17] which could negatively impact some or all of Idaho Power's customers.

[14] The 35 percent was selected based on: (33 MWs of potential program load reduction / 96 MWs maximum CRO required during this time).

[15] Because approximately 83 percent of residential A/C use occurs during heavy load hours, the Company did not calculate the annual levelized benefit derived from using an A/C program during all hours.

[16] For purposes of this report, the Company did not estimate total program costs to run a new CRO program. The amount available for incentives would be net of any program expenses incurred.

[17] I.P.U.C. No. 29, Tariff No. 101, Rule J, Continuity, Curtailment and Interruption of Electric Service, Original Sheet No. J-1: "Load curtailment and interruption carried out in compliance with an order by governmental authority shall follow the Company's plan entitled "Load Curtailment and Interruption Procedure," as filed with and approved by the Commission."

If unable to adhere to the NERC BES reliability standards, the Company could be exposed to significant fines, which could have a financial impact to the Company and its customers, with the most severe fines of $1,000,000 per occurrence or violation, per day.

DR Program and Participant Risk

Idaho Power's DR Programs provide both economic and operational benefits to the Company and its customers, and continuation of these programs is important to meeting one of the main objectives of the Company's Demand-Side Management objectives of providing demand reduction as determined through the IRP planning process. The DR Programs are identified in the IRP to help meet potential peak demands caused by extreme conditions in the summer, and the programs are relied upon to serve load and delay the need for building new peaking resources. The Company believes that the risk of impacting its current DR program participation levels is a critical component in the discussion of the overall feasibility of using DR as CRO.

As noted earlier in this Report, it should be emphasized that Idaho Power cannot predict or forecast when it will call on its CRO. Based on the historical data, it is clear the number of events can vary widely, with the number of times CRO was called on in the years of 2009 through 2013 ranging from 63 to 82. However, while those events should not be relied on to predict future events with any degree of certainty, the Company believes it is reasonable to assume that DR participants participating in a reserve-type program would be interrupted far more frequently that DR participants participating in a traditional DR program.

A/C Cool Credit

The Company believes that anytime it dispatches a DR event and cycles a participant's A/C unit off and on, there is a risk that the temperature in the participant's home will increase, creating discomfort and potentially some dissatisfaction with the program.[18] This effect would be amplified if an event were to be called twice on the same day, or even on high temperature consecutive days, as the home's A/C unit may not have been able to catch up from the first event. The Company believes that increasing the number of events a participant is exposed to through the combination of traditional DR A/C Cool Credit events and CRO events seems likely to decrease customer satisfaction, which could inevitably lead to customers opting out of the program. Losing participants both decreases the amount of DR the program is able to provide and places additional costs on the Company as most participants who opt out of the program insist on having the installed device removed.

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[18] On Monday, July 14, 2014, the Company called an A/C Cool Credit cycling event lasting three hours between 4:00 PM and 7:00 PM. The high temperature that day was 103 degrees. The Company received 63 phone calls from participants during the event and 127 calls from participants the day after the event. 117 participants decided to "opt out" of the program, effectively ending their participation in the program.

Irrigation Peak Rewards

Based on the number of times that Idaho Power calls on its CRO, the Company does not believe its irrigation DR Program participants would be willing to accept the unpredictability and number of interruptions that may occur in a given season. The potential number of interruptions (past data shows 63-82 times per year) exceeds what the Company believes an irrigation DR Program participants would tolerate without becoming very frustrated. Manual restarts of the irrigation pumps are utilized for roughly 50 percent of the systems currently enrolled in the program, and even for the participants who have an automatic re-start, the Company believes several of these participants manually check their irrigation systems for proper operation after any type of interruption. As discussed more fully above, Idaho Power calls on its CRO all days of the week at all hours of the day, which might mean that an irrigator would have an interruption that would require a manual restart or check in the middle of the night. Further, because the number of events called per day and duration of those events is unpredictable, participants could be negatively impacted. In fact, several short events are probably more disruptive to the typical irrigation DR Program participant than a single four hour event, as allowed under the current DR program parameters.

RECOMMENDATION

Based on its analysis, Idaho Power believes the operational and compliance risks outweigh the benefits to utilize DR as CRO because: (1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and provide for program costs, (2) the risks for failure to meet NERC standards is far greater than the economic benefit that might be derived, (3) the period of testing that would be required to provide operational certainty of compliance with NERC and WECC requirements would require carrying substantially more than the reserves actually needed for contingency, at a cost to all customers, and (4) the number of CRO events would put too heavy of a strain on the DR participants, thus risking participation in the Company's DR Programs.

The economic benefits, excluding payments to participants, of using DR as CRO are insignificant when compared to the capacity benefit the current DR Programs provide, and while having a dual-purposed program may be conceivable from a technical and compliance perspective, the Company believes that it is not practical from an economic and program participant perspective. The Company believes that the economic, DR program participation and other operational risks identified in this Report are too great to proceed with a pilot at this time. Therefore, the Company believes that it is not feasible to utilize its DR Programs for CRO.