PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

October 31, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

Re: UM 1667—PacifiCorp's 2014 Smart Grid Report

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing its 2014 Smart Grid Report. In support of its report, the Company is also providing an electronic copy of its Smart Grid Financial Model as Confidential Attachment A. Confidential Attachment A is provided under the provisions of the protective order in this proceeding, Order No. 13-279.

PacifiCorp respectfully requests that all data requests in this docket be addressed to:

By e-mail (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, Oregon 97232

Informal questions concerning this filing may be directed to Natasha Siores, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6583.

Sincerely,

R Bryce Dalley /ncs

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: Service List—UM 1667

Smart Grid Annual Report

October 31, 2014

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Executive Summary

This report is an update to the 2013 Smart Grid Report filed in response to Order No. 12-158 in docket UM 1460. Smart grid is the application of advanced communications and controls to the power system, from generation, through transmission and distribution, to the customer. As a result, a wide array of applications can be defined under the smart grid umbrella. This smart grid report focuses on technologies that can be readily integrated with the existing electrical grid infrastructure.

A business case analysis was performed to examine the quantifiable costs and benefits of a smart grid system, as well as each individual component. The net present value of implementing a comprehensive smart grid system throughout PacifiCorp is negative at this time. However, PacifiCorp has implemented specific projects and programs that have a positive benefit for our customers, and explored pilot projects in other areas of interest.

A key effort at PacifiCorp in 2014 is the continued evaluation of advanced metering technologies and development of a business case. This effort consisted of identifying all projected benefits, and defining costs associated with implementing an advanced metering system in the Oregon service territory. Due to widely-varying manufacturer cost data, a request for proposal was issued to all major metering system vendors to obtain precise fixed costs. Proposals are in the process of being evaluated with the objective of having the business case updated by 12/31/2014.

Commission Recommendations

At the conclusion of the 2013 Smart Grid Report, the Public Utility Commission of Oregon made several recommendations, which are summarized in Table 1. Each recommendation is addressed on the page listed.

Table 1 – Summary of Projects

Category	Recommendation	Page
Transmission Enhancements	Report on dynamic line rating	8
	Report on synchrophasors	11
Substation and Distribution Enhancements	Update on centralized energy storage	14
	A future assessment of communicating faulted circuit indicators	15
	Propose reliability and quality of service metrics	16
	Continue to evaluate integrated volt/var optimization	18
Customer Information and Demand-Side Management Enhancements	Report the results of the Oregon advanced metering project	22
	Explore demand response pilots/programs in Oregon	25
	Full financial analysis of direct load control demand response programs (including Cool Keeper, water heating, commercial cold storage, other commercial & industrial)	25
Distributed and Renewable Resource Enhancements	Analysis of work integrating distributed generation and renewables (including electric vehicles and solar power)	32
Other Recommendations	Include a roadmap	38
	Provide an integrated view of all its smart grid technology efforts with regard to the distribution management system, including outage management	16
	Evaluate traditional non-smart grid investments and applications	22
	Cost/benefit analysis	37, App. A

Smart Grid Strategies, Objectives and Goals

The purpose of this smart grid report is to define the scope and philosophy of the smart grid for PacifiCorp, identify the strategies, objectives, and goals required to meet that definition, and examine the financial characteristics required of an investment that would attain these goals. A potential roadmap for the future is presented at the end of the report, which aligns the relative start dates for various components in order to give an understanding of the progress required to reach a full smart grid deployment with an aggressive schedule. However, the starting date and schedule of progression of any effort must be driven by the fundamental economics laid out in a financial analysis in order to protect the Company and its customers' best interests.

PacifiCorp considers the following strategies necessary to realizing a smart grid:

- Ensure that smart grid investments support providing adequate service at reasonable and fair prices by comparing products and solutions in a financial model that highlights the most beneficial solution configurations;
- Institute cost-effective standards and equipment specifications that enable implementation of smart grid-compatible devices, either through retrofitting where appropriate or through replacement due to equipment obsolescence or failure;
- Work with manufacturers to discuss smart grid products and determine their applicability to PacifiCorp's system; and
- Research industry projects and work with industry organizations, such as the National Electric Energy Testing Research and Applications Center, in order to apply this knowledge to PacifiCorp's benefit.

A number of short-term objectives have been identified as part of the smart grid efforts at PacifiCorp:

- Continually improve customer relations through customer communications and web portal work;
- Draft an advanced meter solution for Oregon by the end of 2014; and
- Implement a custom meter data management system by the end of 2014 that is scalable for future smart grid data throughput.

By implementing the objectives mentioned above, the Company expects to be able to reach the following long term smart grid goals:

- Increase customer awareness and understanding of how the electric system works and how electricity usage impacts and drives Company investments and operations;
- Give customers tools they can use to change their electricity usage in ways that benefit themselves and society; and
- Optimize PacifiCorp's electric system through the application of cost-effective smart grid technologies.

It is PacifiCorp's goal to leverage smart grid technologies in a way that aligns with the integrated resource plan goals and to optimize the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers. This overall goal attempts to work in synchronicity with state commissions, whose goals include improving reliability, increasing energy efficiency, enhancing customer service, and integrating renewable resources. These goals will be met by utilizing strategies that analyze total cost of ownership, performing well-researched cost benefit analyses, and focusing on customer outreach.

Projects Overview

PacifiCorp has implemented a number of smart grid-related projects and programs. Our projects are chosen on their merits to cost-effectively improve service to the Company's customers. These projects can apply to any sector of the power system, which synergistically support a smart grid concept, depicted in Figure 1.

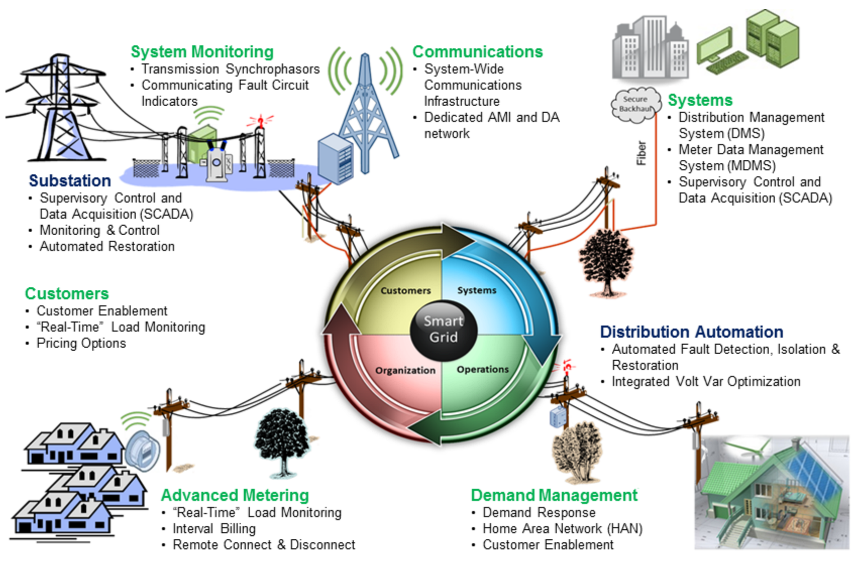

Figure 1 – Select Smart Grid Components

Many of the smart grid technologies are dependent upon preceding technology deployment for the full benefit. As illustrated in Figure 2, all applications depend upon a wide area network for full functionality.

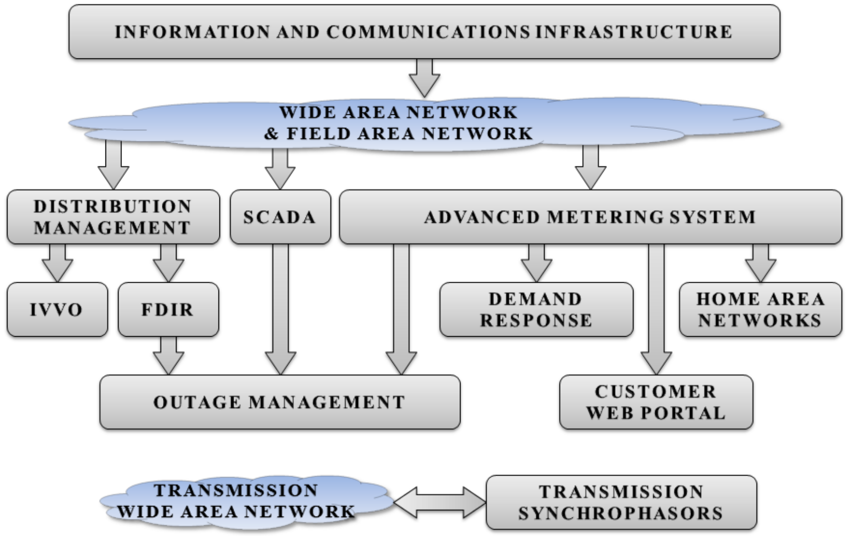

Figure 2 – Smart Grid Technology Dependencies

The following section describes the individual projects, programs, and efforts in detail. These are displayed spatially in Figure 3.

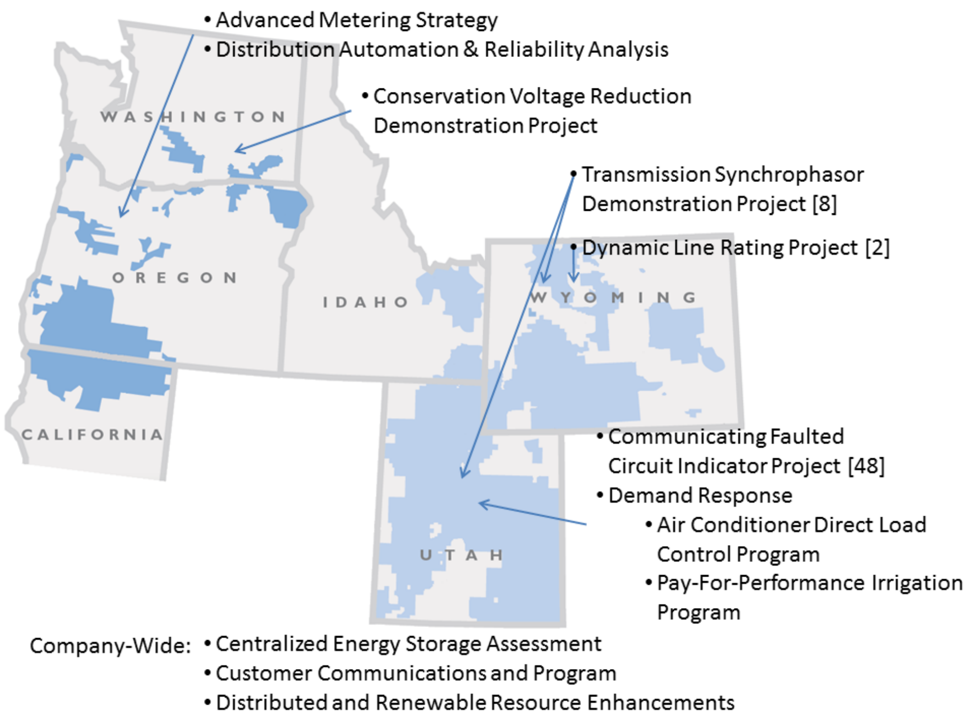

Figure 3 – PacifiCorp Smart Grid Projects

Project status and timeline is summarized in

Table **2**.

Table 2 – Summary of Projects

Project	Status	Timeline
Dynamic Line Rating	One project complete. 2nd project, West-of-Populus, ongoing	West-of-Populus project fully functional expected 2015-2016
Transmission Synchrophasor Demonstration	PacifiCorp's Western Interconnection Synchrophasor Project responsibilities complete	Awaiting data access from WECC; expected 2015
Centralized Energy Storage Assessment	Complete	N/A
Communicating Faulted Circuit Indicators	Ongoing validation and analysis	Validation and analysis by Spring 2015
Distribution Automation & Reliability Analysis	Complete	N/A
Conservation Voltage Reduction Demonstration	Complete	N/A
Advanced Metering Strategy for Oregon Customers	Ongoing business case analysis	Decision early 2015
Customer Communications and Programs	Complete	N/A
Demand Response	Complete	N/A
Distributed and Renewable Resource Enhancements	Complete	N/A

Projects 1: Transmission Network and Operations Enhancements

Transmission projects include dynamic line rating and transmission synchrophasors (TSPs).

Dynamic Line Rating Project

Dynamic line rating is the application of sensors to transmission lines, which indicate the real-time current-carrying capacity of the lines. Transmission lines are generally rated by an assumption of worst-case condition of the season (e.g., hottest summer day or coldest winter day). Dynamic line rating allows an increased capacity during times when this assumption does not hold true.

Project Summary
Two dynamic line rating projects were implemented in 2014. One project, Miners-Platte, is operational. The other project, West-of-Populus, requires further data collection and analysis. West-of-Populus is planned to be operational in 2015.

Project Description and Analysis
PacifiCorp engineering standards currently use static winter and summer thermal limits to rate lines. The static ratings are based on conservative assumptions of ambient conditions that impact the temperature of the conductor. Dynamic line rating systems utilize real-time measurements of conductor load and ambient conditions to calculate steady-state and transient conductor thermal

capacity. The installation of dynamic line rating systems in certain locations will allow the Company to improve system capacity by rating constrained lines based on real-time conditions, rather than the static seasonal ratings. For example, dynamic line rating systems offer significant benefits in areas of the system where transmission line loading is dependent upon output from wind generation facilities, and line loading tends to increase or decrease in conjunction with thermal capability of the line. Dynamic line rating systems only provide a benefit where conductor thermal performance is the limiting element on a given line, and may not provide benefits if system voltage or other constraints limit the capability of a given area of the system. Additionally, operator procedures to determine appropriate system adjustments in response to a reduction in dynamic rating should be considered. Company planners and engineers must keep these factors in mind when determining locations for potential dynamic line rating application.

PacifiCorp identified two locations within its transmission system where real-time dynamic thermal line rating systems offered potential benefits. These locations were identified as needing transmission expansion during PacifiCorp's normal transmission planning process and dynamic line rating was determined to be an applicable solution (e.g. the transmission was thermally constrained, and the time periods and capacities required were coincidental with that made available with dynamic line rating).

Table 3 – DLR Activity Timeline.

Activity	**Time Period**
Miners-Platte	
Equipment Installation	Early 2012
Data Collection & Analysis	Summer 2012
Ratings Process	Mid-2012 – Mid-2013
In Service	End of 2013
West-of-Populus	
Equipment Installation	2013
Data Collection	2013 – ongoing
Ratings Process	2015
In Service	Expected 2015-2016, dependent on analysis and quality of data

The first location selected for installation of dynamic line rating equipment is a 31-mile section of 230 kV transmission line between Miners and Platte substations in south-central Wyoming. The steady-state thermal rating of this particular line segment was one of the limitations on the Western Electricity Coordinating Council (WECC) TOT4A transmission path, and multiple wind farms impact the loading of the line segment. The second location selected for installation of dynamic line rating equipment is three 345 kV transmission lines west of Populus substation in southeast Idaho with a combined length of 147 miles. In this particular installation, the system capacity of West-of-Populus is limited by post-contingency loading of one of the lines following the loss of the other two. Refer to Figure 4 (left) for a simplified map of the 230 kV system in south-central Wyoming where the Miners-Platte dynamic line rating system was installed. Refer to Figure 4 (right) for a map of the 345 kV transmission system near Populus substation, where the West-of-Populus dynamic line rating system was installed.

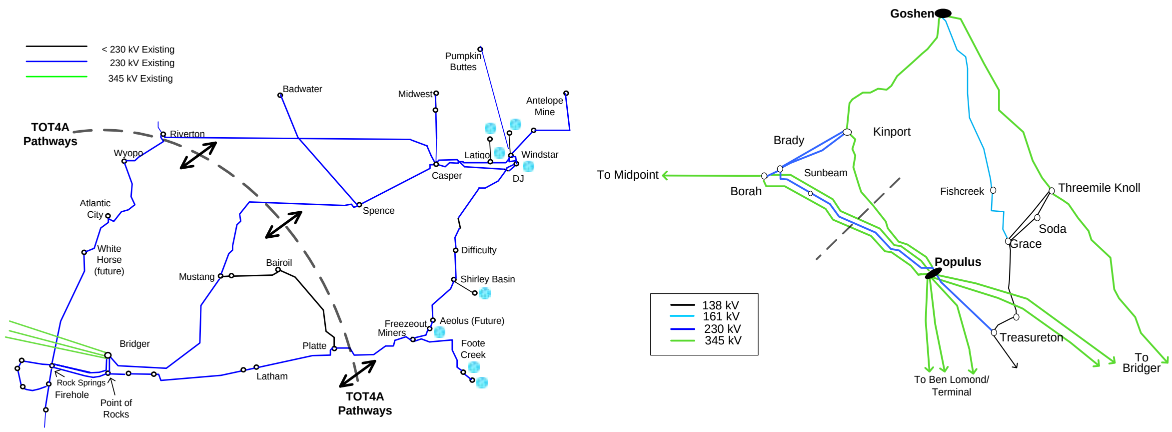

Figure 4 – (Left) TOT4A and the Southern-Wyoming 230 kV Transmission System. (Right) Simplified Transmission System near Populus Substation.

PacifiCorp selected the CAT-1 line monitoring system offered by The Valley Group for both projects. The CAT-1 system calculates real-time line ratings using line section tension readings from load cells installed on the lines. Measurement data is taken from multiple sensing locations throughout the lines, and the data is communicated via radio to a central master station. The master station processes the measurement data and communicates line ratings and other system information to the Company dispatch center. The information is converted to a screen display that shows the real-time maximum rating of the line, thereby enabling dispatch decisions utilizing the real-time thermal capability of the line.

The Miners-Platte installation is complete and in-service. System studies were completed to determine the project benefits and the TOT4A WECC path rating was increased. The maximum non-simultaneous TOT4A path rating was increased from 810 megawatts (MW) to 960 megawatts as a result of the dynamic line rating system in conjunction with other system improvements. Real-time operating limits of the TOT4A path are determined in conjunction with loading on the adjacent TOT4B WECC path; however the TOT4A capacity increase resulting from the dynamic line rating installation at typical TOT4B load levels exceeds 100 megawatts. Refer to Figure 5 for the current TOT4A / TOT4B operating nomogram. The dynamic line rating system benefits are limited to the winter static operating nomogram to prevent operation of the system above voltage limitations on the path. Therefore, the winter static curve in Figure 5 is representative of the maximum possible benefit from the Miners-Platte dynamic line rating system without further transmission improvements.

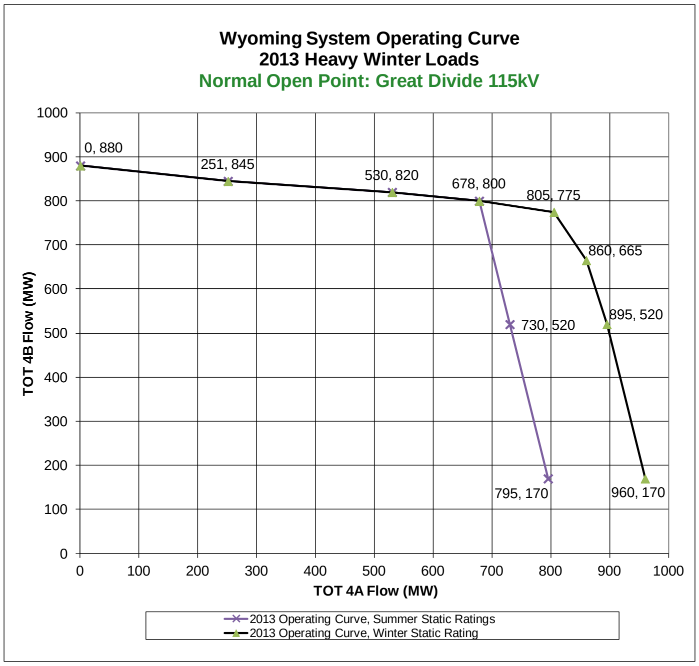

Figure 5 – TOT4A/TOT4B Nomogram

The dynamic line rating installation on the 345 kV lines West-of-Populus is currently in a data collection and analysis phase to determine an optimal strategy to incorporate the system into real-time operations. Hardware installation is complete at this time, and the system is reporting real-time line ratings. Data collection and analysis is ongoing.

Future Actions

Further analysis is necessary on the West-of-Populus dynamic line rating system to determine an optimal strategy to incorporate the system into real-time operations. This effort will be completed and operational in early 2015.

Dynamic line rating is considered for future transmission needs. Dynamic line rating is only applicable for thermal constraints and provides capacity only during site-dependent time periods, which may or may not align with the expected transmission need. Dynamic line rating is one method within the toolbox of transmission planning and is considered when applicable.

Transmission Synchrophasor Demonstration Project

Transmission synchrophasors, also called phasor measurement units, can lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement[1]. The phasor measurement unit can also be used to increase reliability by synchrophasor-assisted protection due to line condition data being relayed faster through the

[1] U.S. Energy Information Administration. (2012, Mar. 30). *New technology can improve electric power system efficiency and reliability* [Online]. Available: http://www.eia.gov/todayinenergy/detail.cfm?id=5630

communication network. Future applications of this precise data could be developed to dynamically rate transmission line capacity, real-time and real-condition path ratings, and real-time power factor optimization. Such dynamic ratings would require vast changes in the current contract path (a transmission owner's rights to sell capacity are based on contracts, not actual flows) transmission capacity methodology currently employed by PacifiCorp and other transmission operators in the WECC. Phasor measurement unit implementation and further development may enable transmission operators to integrate variable resources and energy storage more effectively into their balancing areas and minimize service disruptions. A self-healing transmission grid would reduce outages by "detouring" energy to other paths with available capacity.

The early benefits of synchrophasor installation and intelligent monitoring of the transmission system are focused on increased reliability. The deferral or elimination of new or upgraded transmission lines is not facilitated by the synchrophasor program as envisioned in this report. Further research may reveal whether dynamic ratings can help reduce the future need for additional transmission lines. Transmission energy storage and load reductions could defer or eliminate the need for additional central station generation, which in turn would defer or eliminate some future transmission line.

Project Summary

PacifiCorp and other participating utilities have completed installation of all phasor measurement units and have data streaming to WECC since 2013. An additional three phasor measurement units have been installed since the last Oregon smart grid report, for a total of eight units at eight substations. While utility responsibilities are complete, WECC and Peak Reliability are continuing to develop data access for utility participants. The system of synchrophasors will support WECC and Peak Reliability in the prevention of system blackouts, as well as provide historical data for the analysis of any future power system failure. The data may prove useful for utility operations in the future.

Project Description and Analysis

PacifiCorp participated in the WECC Western Interconnection Synchrophasor Project[2], a collaborative effort between partners throughout the U.S. portion of the Western Interconnection. The project will support WECC and Peak Reliability, which was formed through a division of WECC, to maintain the stability of the power system. The synchrophasors will be used by WECC and partners to identify and analyze system vulnerabilities and disturbances on the western bulk electric system and take timely actions to avoid wide-spread system blackouts.

[2] U.S. Department of Energy. *Western Electricity Coordinating Council: Western Interconnection Synchrophasor Program* [Online]. Available: https://www.smartgrid.gov/project/western_electricity_coordinating_council_western_interconnection_synchrophasor_program

PacifiCorp completed installation of phasor measurement units at eight substations:

- Camp Williams (Utah)
- Emery (Utah)
- Mona (Utah)
- Populus (Utah)
- Dave Johnston (Wyoming)
- Jim Bridger (Wyoming)
- Monument (Wyoming)
- Wyodak (Wyoming)

PacifiCorp also installed two phasor data concentrators at the PacifiCorp Salt Lake City control center, which are capable of streaming data to WECC and Peak Reliability. The phasor data concentrators collect and archive real-time data streams from remote substation site phasor measurement units and transmit the real-time data to WECC in Vancouver, Washington.

WECC has developed the "wide area view" tool[3] to enable situational awareness. The wide area view tool can allow users to see all of the connected participating phasor measurement unit sites in the Western Interconnection and any available real-time data that they provide. The wide area view tool has been live since 2013[4], but only limited data from a small number of phasor measurement units are available.

Peak Reliability is continuing to work to "improve the quality and use of the synchrophasor data it receives". "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 documentations/procedures;
4. Deploy automatic controls; and
5. Make data availability efficiency improvements, including employing a more efficient and reliable system for distributing synchrophasor data."[5]

PacifiCorp will continue to work with Peak RC to determine how to best use the available phasor measurement unit data for situational awareness using the Peak RC wide area view tool or an in-house tool. PacifiCorp completed its Western Interconnection Synchrophasor Project equipment installation responsibilities, but will not be able to submit feedback from using the wide area view tool until we are able to support the PacifiCorp-installed equipment and network

[3] Peak Reliability. *WAV* [Online]. Available: https://www.peakrc.org/Realtime/Pages/WAV.aspx
[4] WECC. *WECC Newsletter October 2013*.
[5] Peak Reliability. *Peak Reliability June 13, 2014 Release* [Online]. Available: https://www.peakrc.com/Business/Press%20Release%20Peak-DOE%2006-13-2014%20Final%20.pdf

connections, and the Peak RC wide area view tool is more comprehensive for PacifiCorp and its neighboring utilities. Future smart grid reports will include updates on the synchrophasor project and the results from using the wide area view tool.

Future Actions and Timeline

Participating utilities completed installation of all phasor measurement units in 2013 and have data streaming to WECC. While utility responsibilities are complete, WECC is continuing to develop data access for utility participants. The system of synchrophasors will support WECC and Peak Reliability in the prevention of system blackouts, as well as provide historical data for the analysis of any future power system failure. While WECC and Peak Reliability responsibilities of the Western Interconnection Synchrophasor Project are ongoing, the data may prove useful for utility operations in the future. At present, PacifiCorp has no plan to implement more synchrophasors; additional installation will be considered after the Western Interconnection Synchrophasor Project proves fruitful.

Projects 2: Substation and Distribution Network and Operations Enhancements

Substation and distribution projects include centralized energy storage (CES), communicating faulted circuit indicators, distribution automation, operational management systems, conservation voltage reduction, and integrated volt/var optimization (IVVO).

Centralized Energy Storage Assessment

Centralized energy storage includes large, centralized storage resources, such as electrochemical batteries, pumped hydro, and electromechanical batteries (i.e., flywheels). One of the benefits of the smart grid is the ability to integrate renewable energy sources into an electricity delivery system. In contrast to “dispatchable” resources that are available on demand, such as most fossil fuel generation, some renewable energy resources have intermittent generation output due to their fuel source of wind or photovoltaic solar. The generation output of these resources cannot be increased and have high opportunity cost when generation is decreased. Providing service to the electrical grid becomes increasingly challenging as the amount of the grid’s energy requirements are served more and more from these intermittent resources. Two ways to fill this generation gap without the use of dispatchable resources are demand response (DR) programs and centralized energy storage.

Project Summary

PacifiCorp completed an energy storage screening study in support of integrated resource planning.

Project Description and Analysis

As part of integrated resource planning, PacifiCorp commissioned an energy storage screening study, which was completed in December 2011 and updated in July 2014. The study provides a current catalog of commercially available energy storage technologies.[6]

In 2013, PacifiCorp analyzed various centralized energy storage systems to study their effectiveness in improving asset utilization as well as transmission and distribution upgrade deferral. It was found that a single substation storage device is beneficial to provide incremental capacity to defer a minimal investment in substation equipment. For a significant transmission and distribution upgrade deferral, multiple substation storage devices in a single substation or multiple substations would be required. Furthermore, centralized energy storage devices do not provide any benefit to reduce future circuit infrastructure. On the other hand, localized energy storage technology (in which storage units are placed downstream from substations) provides the most benefit in avoided future infrastructure. However, in coordination with PacifiCorp's current subdivision design standards that are designed for the most effective and efficient operation of the distribution system, the commercially available localized energy storage devices would be heavily underutilized due to their limited kilowatt (kW) size. Also, increased losses from additional distribution transformers, increases in capital infrastructure cost per subdivision, as well as cold load pickup are issues that would need further detailed evaluation.

Future Actions and Timeline

PacifiCorp will continue to evaluate energy storage for future resource and system needs.

Communicating Faulted Circuit Indicators

Traditional non-communicating faulted circuit indicators are used to visually indicate fault current paths on the distribution system, while communicating faulted circuit indicators wirelessly send a signal to the utility. Communicating faulted circuit indicators have the potential to improve reliability indices, such as customer average interruption duration index (CAIDI), by reducing the amount of time associated with initial fault reporting and determining fault location.

Project Summary

PacifiCorp installed 48 communicating faulted circuit indicators in early 2014 as indicated in the 2013 Oregon smart grid report. Future actions include integration with PacifiCorp's outage management system, validation, and cost/benefit analysis; these actions are anticipated to be complete in spring of 2015.

[6] HDR Engineering, Inc. *Update to Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Energy_Storage-Screening-Study-July2014.pdf

Project Description and Analysis

In 2013, PacifiCorp completed an assessment of commercially available communicating faulted circuit indicators, reviewing features and physical form factors that may prove most beneficial. Measurement capabilities, physical device size, auxiliary power, and communication infrastructure requirements were evaluated. Cellular-based distributed network protocol communications, fault magnitude measurement, profiling of line current, and a form factor suitable for installation on a wide range of conductor sizes were identified as the critical components necessary for a successful communicating faulted circuit indicator deployment on PacifiCorp's distribution system.

Future Actions and Timeline

PacifiCorp Engineering implemented a pilot project, installing 48 communicating faulted circuit indicators on five circuits in eastern Utah in March 2014. These circuits had poor reliability, were in difficult-to-access rural areas, and had limited supervisory control and data acquisition (SCADA).

Sensor alerts and loading data are currently being hosted through a vendor-hosted web portal accessed by area engineers and dispatchers. A project to integrate communicating faulted circuit indicators sensor data with the Company's outage management system is in progress. Integration of the communicating faulted circuit indicators and outage management system is expected to provide operation personnel with an enhanced view of system status and accelerate the use of the data from new equipment. Validation of sensor performance is on-going; a cost-benefit analysis should be complete by spring of 2015. Given positive results this technology will be considered for similar circuits elsewhere. An update on this project will be included in subsequent smart grid reports.

Distribution Automation and Reliability

Distribution automation, also known as fault detection, isolation, and restoration (FDIR) or fault location, isolation, and service restoration, utilizes strategically-placed, communication-enabled fault detection devices, distribution reclosers and motor-operated switches to automate restoration. These systems enable the utility to remotely or automatically reconfigure the distribution network in response to an outage. The devices communicate their status to a distribution management system (DMS), which determines the fault location and then sends out a signal to open or close fault isolation devices and switches to restore the maximum number of customers in areas outside the fault zone.

Project Description and Analysis

PacifiCorp has evaluated the reliability impacts and cost of distribution automation within the Oregon service area. For the implementation of distribution automation the Company would begin by installing the devices at each existing switch and reclosing device in the state, of which there are approximately 36,000 locations. This equipment installed, at an estimated average cost $21,000 per location, totals $730,000,000.

The Company estimates that the distribution automation would reduce sustained outage frequency to its Oregon customers by 8 percent and outage duration by 6 percent, improving reliability by an average of seven minutes per customer per year.

Using a cost per avoided customer minute metric, these improvements would result in a cost of $167/customer minute interrupted, which is approximately 300 times more costly than the improvements the Company funds in its normal targeted reliability programs.

Future Actions and Timeline
PacifiCorp will continue to evaluate smart grid technologies for system reliability needs.

Distribution Management

Greater precision in operational data and minute-by-minute management is critical to long-term success as distribution systems become more sophisticated. A distribution management system provides the utility with a variety of advanced analytical and operational tools for managing complex distribution systems and integrates several systems and functions that are currently operated independently, specifically outage management, switching operations, lock-out and tagging procedures, fault calculations, load flows, and real-time state estimation routines.

When combined with an integrated volt/var optimization program that interacts with different types of substation and line equipment, the distribution management system can manage voltages to minimize line losses and energy needs while maintaining customer voltage quality in compliance with established standards. A distribution management system utilizes strategically placed equipment, including distribution transformers, distribution reclosers, motor-operated switches and fault detection devices as data sources for an electronic model that records and calculates key values integral to system operation. Such a holistic infrastructure enables remote operation of several lines and substation equipment potentially enhancing the efficiency of the distribution system. Operational efficiency can be gained as these integrated subsystems perform calculations, autonomously choose the appropriate actions, and then carry out those actions. For security, some designs call for an effective extension of the utility's firewall to include the field intelligent electronic devices. The intelligent electronic devices then act as cyber security agents to detect and mitigate threats.

A distribution management system creates an intelligent distribution network model that provides ongoing data analysis from field-deployed intelligent electronic devices to maximize the efficiency and operability of the distribution network. A complete distribution management system provides distribution engineers with near real-time system performance data and highly granular historical performance metrics. This will support system planning, increases visibility of the system status and improves reliability metrics through better application and management of the distribution capital budgets.

With appropriate data inputs from field intelligent electronic devices, the distribution management system will be able to analyze the distribution network for both normal and emergency states and perform the following functions required for integrated volt/var optimization and fault detection, isolation, and restoration:

- Monitor unbalanced load flow and determine if there are any operational violations for normal state and reconfigured distribution feeders;
- Determine the optimal positions and operating constraints for the various power transformer taps, line voltage regulators and capacitors along a distribution feeder and manage the open/closed positions of these devices;
- Receive fault data and run a short circuit analysis to determine the probable location(s) of faults;
- Analyze the system during abnormal conditions and determine the optimal redistribution of available load to adjacent feeders and substations;
- Suggest the switching sequence required to isolate the fault and restore power, to as much load as possible, outside the fault zone; and
- Suggest the switching sequence for line unloading should a condition arise where an operator needs to reduce the load on a specific device.

Outage Management

All electrical distribution systems are subject to faults caused by storms and other external events as well as failures related to aging and overloaded systems. When these faults and failures occur, protective devices such as circuit breakers, reclosers, sectionalizers and fuses operate to limit the resultant outage to the smallest practicable area. Information on the outage is currently obtained through supervisory control and data acquisition systems, where available, and/or notifications to the Company's customer service call centers. These notifications, when interfaced with the Company's connectivity model, inform the Company that an outage exists and allows for the dispatch of personnel to manually identify the location and restore service to areas outside the fault zone. When appropriate amounts of data are received from customers, intelligence within the current outage management software can make assumptions as to where a fault may have occurred. To accelerate service restoration times, the integration of intelligent electronic devices in distribution line equipment (specifically reclosers, sectionalizers and faulted circuit indicators) provides the outage management system with intelligence that can be used to isolate the faulted sections of the system in reduced timeframes.

Conservation Voltage Reduction Demonstration

Conservation voltage reduction is the reduction of voltage within an acceptable lower limit, which can result in customer (demand-side) energy savings. Conservation voltage reduction is accomplished by intentional design and operation strategies such as:

- phase balancing,
- economically sizing conductors, and
- line drop compensation (Figure 6, right),

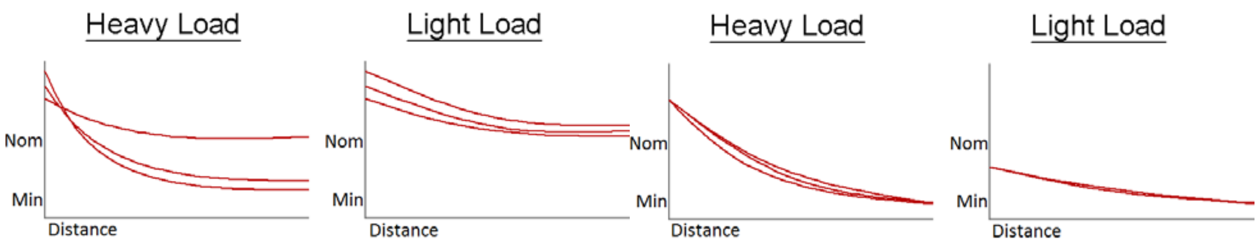

**Figure 6 – (Left) Voltage profile of a poorly-operated circuit.
(Right) Voltage profile with phase balancing, economically-sized conductors, and line drop compensation.**

- implementation of line regulators (Figure 7, left), and
- implementation of capacitors (Figure 7, right).

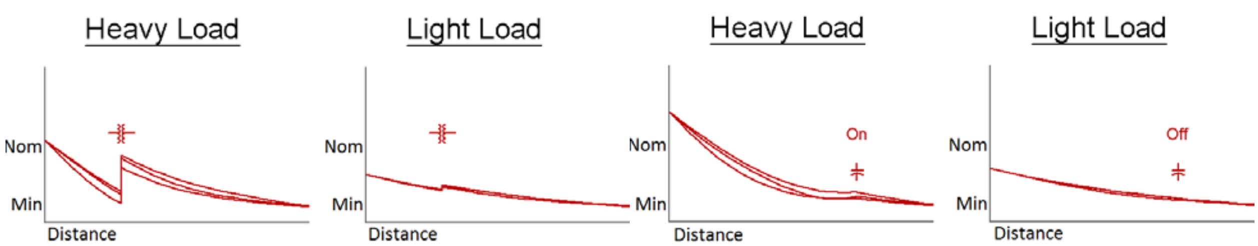

**Figure 7 – (Left) Application of line regulators.
(Right) Application of capacitors.**

The outcome of an ideal application of conservation voltage reduction is depicted in Figure 8 (left), which shows a flattened and minimized voltage level.

A more advanced application, integrated volt/var optimization, is depicted in Figure 8 (right). Integrated volt/var optimization uses sensors and automated and/or telemetric control to optimize feeder voltage in real time.

**Figure 8 – (Left) Ideal application of CVR.
(Right) Integrated Volt/Var Optimization.**

Conservation voltage reduction and integrated volt/var optimization can lower the voltage towards the minimum allowable voltage, which can reduce energy usage. However, a distribution system that is already maintained at a low voltage will see a negligible impact.

Project Summary

Washington State studies and voltage reduction pilot, 2010-2012, evaluated (1) how to identify circuits with energy savings potential, (2) engineering and operational challenges related to implementing consultant-recommended solutions and (3) methods used to verify and measure the associated energy savings. Findings showed that reducing voltage on these high-potential circuits was not cost-effective.

Project Description and Analysis

PacifiCorp's conservation voltage reduction activities began in 2010 as a response to a Washington voter-approved initiative, codified as the Revised Codified Washington 19.285[7] in Washington State. This initiative calls for regulated utilities to pursue cost-effective, reliable, and feasible distribution efficiency savings. PacifiCorp worked with the Washington Utilities and Transportation Commission's Demand-Side Management Advisory Group to define a conservation voltage reduction pilot scope and cost recovery mechanism in order to ensure compliance with the state's requirements.

Consultants with conservation voltage reduction expertise were employed to determine achievable energy savings in our Washington service territory, and the four most promising circuits were chosen for a 2012 voltage reduction pilot. Among the conclusions affecting the business case were (1) substantial engineering overhead related to detailed customer and circuit analyses, (2) the circuit improvements, metering and long-term analysis necessary for a multiple-decade savings forecast needed to be repeated when circuit and substation configurations changed, (3) the model predictions were not corroborated by field data and (4) the pilot did not generate the measurable and verifiable energy savings calculated by the consultants.

Over two years, the most promising 19 Washington circuits were studied for energy savings potential. Based on the results of two commissioned engineering studies, the most promising four circuits were selected for an efficiency improvement and voltage reduction pilot project. Of the 0.09 average megawatts predicted to be acquired through the four pilot circuits, less than 0.01 average megawatts was actually achieved. Both before and after voltage reduction, all four circuits failed to meet the protocol efficiency thresholds required for rigorous measurement and verification. Thus, the energy savings could not be verified by an approved method, since the Simplified Protocol[8] scope requires that the thresholds be met.

[7] Washington State Legislature. (2007). *Chapter 19.285 RCW Energy Independence Act* [Online]. Available: http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285
[8] Regional Technical Forum. (2010). *Utility System Efficiency: Voltage Optimization Protocol* [Online]. Available: http://rtf.nwcouncil.org/measures/measure.asp?id=180

The estimated savings from the metered data, ignoring the threshold violations, were used to calculate benefit-to-cost ratios and the cost of the energy savings. Costs were significantly higher than the avoided purchased energy rate used in Washington. Due to protocol threshold violations, confidence in both the voltage reduction value and energy savings value are consequently very low. Additional risks were also identified, such as the need to move an end-of-line metering installation for a customer development project (a new entrance to a school) and load transfers to a new circuit, which made meter locations and benchmark energy data obsolete.

The pilot project showed that actual energy savings are likely to be less than 10 percent of that predicted by detailed analysis. The 2012 study highlighted limitations in circuit analysis as a project risk and led to the conclusion that energy savings from voltage reduction cannot currently be reliably acquired at PacifiCorp. The primary reasons identified are low existing voltage, low load density, and limited meter data at both the feeder and customer levels for time-series analysis.

Engineers across the Company's six-state service territory utilize the same guidelines when determining the proper settings for regulating devices, and economic system improvement projects are compared and prioritized at a corporate level. While load density and available data varies from circuit to circuit, the conclusions from the recent effort are applied to multiple states because the most detailed professional analysis available, applied to the most promising, energy-dense distribution circuits in Washington showed no measureable savings, and therefore no avenue to determine a benefit-cost ratio for other voltage reduction projects. Across the six states, a high-level circuit screening was performed to compare energy density and other influential factors; the Company's conclusion is that no other circuits show promise at this time. The results are representative of PacifiCorp as a whole given that company engineering practices are common throughout the service areas.

Existing company practices were a principal component of the 2010-2013 analysis. These practices include utilizing line drop compensation and minimizing the total cost to company and customer through prudent system improvements, including prioritized reconductor projects with economically-sized conductors, regulators funded only after voltage recording confirms substandard voltage and economically-sized secondary conductors. These practices tend to have a negative effect on any additional conservation voltage reduction business case since the Company has already gained much of the financial benefits of typical conservation voltage reduction projects (i.e., the voltage is already relatively low). The Company is also beginning the process of transitioning to a new, more powerful circuit analysis application that will allow better customer load modeling and time series analysis. This will help ensure that future settings and project justification efforts are as accurate as possible.

Future Actions

PacifiCorp currently has no plans to implement conservation voltage reduction as a standard operating practice. The Company will continue to monitor industry activities, methodologies, and technology and will regularly re-evaluate the applicability of conservation voltage reduction and integrated volt/var optimization to the distribution system.

Projects 3: Customer Information and Demand-Side Management Enhancements

These are customer-focused projects, including demand-side management (DSM). These include advanced metering, demand response, home area network, and customer communications and programs.

Advanced Metering Strategy for Oregon Customers

PacifiCorp expended considerable effort during 2014 further developing and refining its strategy related to an advanced metering system (AMS) in the state of Oregon. Potential benefits as well as costs were researched, evaluated, and refined, producing multiple business case models. PacifiCorp's objectives were threefold; identify a solution and strategy that would deliver solid projected benefits to our customers, deliver financial results that make economic sense, and minimize impact on consumer rates.

<u>Approach</u>
Major industry leading vendors were invited to participate in a request for information proposal put forth by PacifiCorp in early 2014. Each vendor produced a lengthy document that described their business, what products they can deliver, which electric utilities have implemented their products, and benefits their customers have realized as a result of actual implementations. Vendors also delivered onsite product demonstrations, which provided a forum for hands-on evaluation.

<u>Request For Information Results</u>
Each vendor approaches implementing an advanced metering system in its own unique way. Two fundamentally different approaches exist. The first approach utilizes point to multi-point technology utilizing remotely stationed towers that communicate with individual meters. The second approach utilizes a meshing scheme in which a group of meters communicate with a collector device. Two vendors also proposed a phased approach in which automated meter reading (i.e., drive-by) technology is utilized for a period of time with the capability of converting to a two-way system at some point in the future. Further discussion on the phased approach follows in this document.

PacifiCorp has focused on four key aspects for delivering an advanced metering system. The first considered what type of system to implement. The second focused on how to implement a system. The third, and arguably the most important, considered what benefits and costs our customers would actually realize and the fourth looked at the ongoing cost to operate the system. Vendor costs varied significantly as were the benefits realized/claimed by other utilities. As a result, vendor data proved inconclusive given the wide range in data and difficulty in quantifying the benefits actually realized by other utilities.

Request For Proposal

In order to refine the costs of implementing an advanced metering system, a decision was made to proceed with a formal request for proposal aimed at further refining the business case. The request was issued on September 2, 2014, with a due date of October 15, 2014. Seven vendors responded and proposal evaluation is underway at this time. We expect to complete the evaluation and economic analyses no later than December 31, 2014, with a decision being made in early 2015.

Phased Approach

As previously stated, two vendors presented the option of implementing an advanced metering system in a phased approach. The phased approach would allow an advanced meter solution to be implemented in two phases, following a schedule determined by future benefits and cost factors. The system would operate in phase one in a drive-by meter reading mode and would include additional capabilities and benefits above and beyond basic drive by meter reading. Remote connect and disconnect capability from the street would be enabled resulting in reduced intrusion onto customer property as well as operational efficiencies. The cost associated with implementation of a communication network and related software would be deferred to a future date at such time it is determined to be financially feasible. The benefits assessed include:

- Meter reading accuracy
- Labor savings
- Collection efficiency
- Reduced property intrusion
- Safety

Implementing a phased approach would result in significant efficiency gains and reduce the possibility of stranding assets; however it may reduce potential benefits that might be realized through a fully automated two way system. A phased approach could also make the financial case for implementing phase two more difficult down the road.

Customer Information System Implications

It is important to note that PacifiCorp's customer information system is not currently capable of leveraging key meter data captured via an advanced metering system. Key functionality, including, but not limited to critical peak pricing cannot be delivered without a new customer information system. Implementing a new customer information system is a major undertaking from both a cost and resource standpoint. Further evaluation and discussions need to occur regarding the respective timing of a customer information system upgrade and an advanced metering system implementation.

Additional Considerations

Other smart grid benefits that could potentially leverage the advanced metering infrastructure (AMI) network were considered and include:

- An expansion of non-firm demand response (i.e., time-based rates);
- Outage management;
- Fault detection, isolation, and restoration; and
- Integrated volt/var optimization.

The costs and benefits for these additional applications are described in Attachment A. However, caution should be used when committing a wide area network to supporting other applications (e.g., communicating faulted circuit indicators, conservation voltage reduction or integrated volt/var optimization, distribution automation, demand response) in addition to advanced metering infrastructure. Communication network traffic may determine the need for independent networks to better serve distinct high-reliability applications.

Conclusion

PacifiCorp made significant headway during 2014 in expanding our understanding of the implications for implementing an advanced metering system. Additional effort needs to take place in order to firmly quantify how much it will cost to implement an advanced metering system in the state of Oregon. Refining the costs further through the request for proposal process will enable us to clarify the economics and better understand the full impact that an advanced metering system will have on our customers. Proposal evaluation and associated economic analyses will be complete in the next 60 days with a decision on how to proceed expected in 2015.

Customer Communications and Programs

Program Summary

As of 2013 customers have access to 24 months of monthly electricity consumption history and the option to download 12 months of monthly electricity consumption history that meets the Green Button standard.

Program Overview

PacifiCorp provides all customers with energy saving information, such as the heating efficiency information, as well as access to view and download up to 24 months of monthly electricity usage history and the option to download up to 12 months of monthly electricity usage that meets the Green Button[9,10] standard specification. Green Button data is formatted in a machine-readable language that customers can use with software applications or provide to a third party to evaluate their energy use. PacifiCorp promotes Green Button and applications such as Energy

[9] Pacific Power. Green Button [Online]. Available: https://www.pacificpower.net/greenbutton

[10] Rocky Mountain Power. Green Button [Online]. Available: https://www.rockymountainpower.net/greenbutton

Star's Home Energy Yardstick as a tool to help customers better understand and manage their electricity use.

PacifiCorp also has an advertising and outreach campaign to increase customer awareness of the benefits of energy efficiency and to drive customer participation in its WattSmart efficiency and cash incentive programs.

In Utah and Washington, the Company provides targeted residential customers with information about their electricity use through home energy reports. The reports use behavioral science principles to compare a customer's electricity use to that of similar homes in the area and provide customized energy-saving recommendations. The program is also in place in Oregon through collaboration with the Energy Trust of Oregon.

By utilizing programs like these and enhancing customer awareness of energy efficiency, PacifiCorp aims to empower its customers to take control of their electricity use to manage their costs. This approach keeps costs down and improves grid efficiencies, which benefits all customers.

Future Actions

PacifiCorp will continue to consider the applicability to customer programs when evaluating smart grid and advanced metering technologies.

Demand Response

PacifiCorp's direct load control programs include Cool Keeper air conditioner (AC) load control and irrigation load control, which is categorized as Class 1 demand-side management under the PacifiCorp integrated resource plan. PacifiCorp also offers Class 3 demand-side management programs, which are time-of-use programs offered to specific customer classes. These demand-side management programs may have the potential to become more robust as better system communication and controls become available.

Demand response programs are used to reduce the peak load, when electricity is generally much more expensive. The PacifiCorp summer peak of 2013 was measured at 10,507 megawatts on July 1. System daily peaks for this time period is shown in Figure 9.

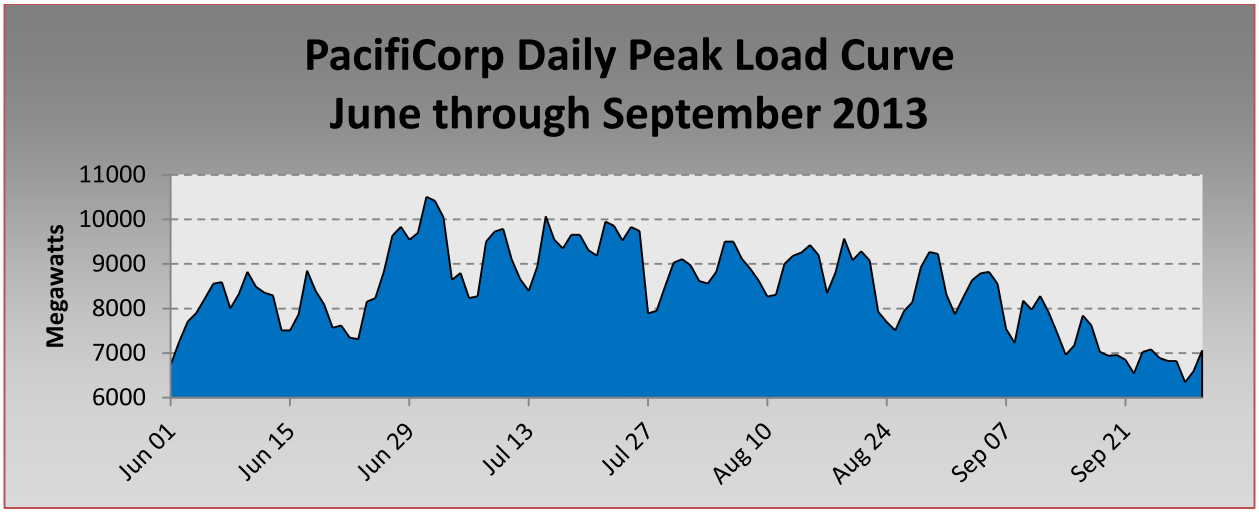

Figure 9 – PacifiCorp Daily Peak Load Curve

Home area network implementation is being explored along with advanced metering. A home area network may better enable customers and loads to participate in demand response by giving customers access to their real-time usage and by delivering pricing signals. However, while the advanced metering system may be used to transmit data to the customer, many utilities are finding that their advanced metering system does not have the bandwidth to incorporate additional applications, such as demand response programs. Increasingly the trend for the transmission of information to the customer is not through the meter, but through other communication channels, such as the internet or application-specific networks.

The Public Utility Commission of Oregon has recommended "that a full financial analysis of direct load control demand response programs be included…, including not only the existing Cool Keeper program but also water heating, commercial cold storage, and other commercial and industrial applications." A financial analysis of direct load control demand response was done as part of the 2013 integrated resource plan with supporting analysis from the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental resources, 2013-2032 Volume I"[11].

[11] The Cadmus Group, Inc. *Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume I* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf

Table **4** lists the Class 1 demand-side management levelized costs, including AC, water heat, and commercial and industrial loads.[12] Costs vary by region. For example, Oregon irrigation demand response costs are higher than Idaho and Utah because there is easier access to surface water, less pumping load, and more geographical dispersion.

[12] Ibid., p. 32, Table 12.

Table 4 – Class 1 DSM: Levelized Costs for Oregon ($/kW-year)

DLC AC – Residential	DLC Water Heat - Residential	DLC AC – Small Commercial	DLC Water Heat – Small Commercial	Irrigation DLC	Nonresidential Load Curtailment
$123	$64	$99	$64	$61	$69

The 2013 integrated resource plan modeling results did not select direct load control demand response until 2020 or later for the scenarios.[13] This indicates that direct load control demand response is not a least-cost resource until that date or later. "Despite finding the resource reasonably viable, it was not selected as an economic resource in the first ten years of the 2013 integrated resource plan preferred portfolio"[14]. Combined-cycle combustion turbines were as low as $54.94/kilowatt-year.[15]

In its integrated resource plan, PacifiCorp implements least-cost, least-risk planning principles to arrive at a preferred resource portfolio and associated action plan. The preferred portfolio selection process begins by developing resource portfolio alternatives using System Optimizer. System Optimizer selects from a broad range of resource alternatives, including direct load control (i.e., Class 1 DSM), taking into consideration the cost, performance, size, and location of each resource alternative and taking into consideration how each resource alternative would affect costs when added to PacifiCorp's integrated system. The cost to acquire or build a resource is only one factor that influences the selection of a given resource type in least cost resource planning. PacifiCorp's 2013 integrated resource plan preferred portfolio does not include either direct load control or simple cycle combustion turbine plants in the front ten years of the planning horizon. Consequently, any comparison of direct load control costs to the cost of a simple cycle combustion turbine plant is not relevant to a recommendation to implement direct load control pilot programs in Oregon.

With a greatly reduced load forecast in the 2013 integrated resource plan as compared to the 2011 integrated resource plan, Class 1 demand-side management resources did not surface in the 2013 integrated resource plan preferred portfolio, or any of the top performing resource portfolios, until well into the next decade. Through the front 10 years of the integrated resource plan 20-year planning horizon, PacifiCorp's least-cost, least-risk preferred portfolio is comprised of Class 2 demand-side management resources (energy efficiency) and front office transactions, which are representative of short-term firm forward market purchases. The cost of these resource alternatives (Class 2 demand-side management and front office transactions), net of the system benefits that these resources provide in PacifiCorp's system, are simply lower-cost alternatives than acquiring direct load control resources, given current projections of resource need, through

[13] PacifiCorp, *2013 Integrated Resource Plan Volume I* [Online]. Page 205. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf
[14] Ibid., p. 257.
[15] Ibid., p. 116.

at least the first ten years of the planning horizon. Given that Class 2 demand-side management and front office transactions are lower-cost alternatives to direct load control, using direct load control to offset firm forward market purchases would only increase portfolio costs.

PacifiCorp included in its 2013 integrated resource plan a flexible resource needs assessment.[16] This analysis identifies the need for flexible resources over the 20-year integrated resource planning horizon and subsequently assesses this need in relation to supply. The analysis clearly demonstrates that PacifiCorp has sufficient flexible resources to serve its needs through the planning horizon. Moreover, PacifiCorp's integrated resource plan modeling framework accommodates the flexible operating characteristics of resources when resource portfolios are analyzed in the Planning and Risk (PaR) model. PaR studies are performed in each integrated resource plan to analyze the relative stochastic risk among portfolios, which influences the selection of the least-cost, least-risk preferred portfolio. Inasmuch as portfolios include direct load control programs that can offer operating reserve capabilities, the operating reserve benefits for those resources are captured in the PaR results.

Other potential system benefits of demand response, such as "programs that increase specific loads during periods of high wind generation and low overall load" are not specifically considered, however the identification of resources and reserves through integrated resource planning addresses this need.

The 2013 integrated resource plan included an action item to "Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program… for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 integrated resource plan."[17] However, there is little need to develop pilot demand response programs. PacifiCorp has significant experience implementing demand response products and will consider implementation of programs that are a least-cost resource when there is a capacity resource need.

<u>**Time-based Pricing**</u>

<u>Project Summary</u>
PacifiCorp has existing time-of-use rates for specific customer classes within each state.

<u>Project Description</u>
Time-based pricing can encourage customers to change energy usage patterns. The most common price signals in the industry today are time-of-use, critical peak pricing and critical peak

[16] PacifiCorp, *2013 Integrated Resource Plan Volume II* [Online]. Page 71. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf
[17] PacifiCorp, *2013 Integrated Resource Plan Volume I* [Online]. Page 250. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf

rebate programs.[18] A combination of time-of-use and critical peak pricing, or time-of-use and critical peak rebate pricing programs, are the most prevalent and, if designed and implemented appropriately, can present opportunities for creating reductions in energy usage during critical periods when system peaks are present.

Table 5 is an updated summary of PacifiCorp's price schedules by state and shows current levels of participation in voluntary program**.**

Table 5 – Summary of Price Schedules by State

Description	State	Schedule	Participating Customers (Dec. 31, 2013)	Eligible Customers	Participating Eligible Customers	Voluntary or Mandatory
Residential TOU Pricing	Utah	2	368	725,783	0.05%	Voluntary
	Oregon	4/210	1,193	478,358	0.25%	Voluntary
	Idaho	36	13,621	58,630	23.23%	Voluntary
General Service (*Business Sector and Irrigation*) TOU Pricing, Either Energy or Demand	Washington	47T	1	1	100%	Mandatory
	Washington	48T	64	64	100%	Mandatory
	California	AT48	17	17	100%	Mandatory
	Idaho	35/35A	3	10,137	0.03%	Voluntary
	Wyoming	33	10	10	100%	Mandatory
	Wyoming	46	81	81	100%	Mandatory
	Wyoming	48T	29	29	100%	Mandatory
	Utah	6A/6B	2,291	96,199	2.38%	Voluntary
	Utah	8	272	272	100%	Mandatory
	Utah	9/9A	159	159	100%	Mandatory
	Utah	10	245	2,999	8.17%	Voluntary
	Utah	31	4	4	100%	Mandatory
	Oregon	23/210	263	75,622	0.35%	Voluntary
	Oregon	41/210	53	5,537	0.96%	Voluntary
	Oregon	47	7	7	100%	Mandatory
	Oregon	48	202	202	100%	Mandatory

Cool Keeper AC Direct Load Control

Project Summary

PacifiCorp has an existing direct load control demand response program, known as Cool Keeper, in Utah.

Project Description and Analysis

PacifiCorp continues the Cool Keeper program in an effort to manage summer peaks in the Wasatch Front area. Residential and small commercial customers participate in the program,

[18] U.S. Department of Energy. *Time-Based Rate Programs* [Online]. Available: http://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs

which allows the Company to manage air conditioning loads. Customers are provided with credit on their bills for their participation. The Cool Keeper program directly controls customers' air conditioners with a radio-enabled device that cycles the compressors off and on. With the current number of Cool Keeper load controls installed the Company has control of up to 111 megawatts of power during critical peak events.

Future Actions and Timeline

Research indicates that over the next 20-year period a total potential of 143 megawatts may be available in the Rocky Mountain Power territory and 27 megawatts may be available in the Pacific Power territory[19]. For the 2014 summer season, PacifiCorp upgraded the existing Cool Keeper system to improve the remote devices and enable measurement and verification of savings during events. This upgrade is expected to further increase the overall efficiency of the direct load control system.

Irrigation Load Control

Project Summary

PacifiCorp has offered an irrigation load control program in various configurations for several years. These programs have been designed to reduce peak load by allowing PacifiCorp to control participants' irrigation loads during periods of peak demand.

Project Description

PacifiCorp selected EnerNOC to manage a ten year irrigation load control program beginning in 2013. EnerNOC's responsibilities include enrollment, equipment installation, dispatch management, performance calculations, and customer service. Along with program management changes, the performance measurement and incentive structure changed substantially from previous years. A new pay-for-performance structure rewards irrigators for the value they provide during program hours, versus peak monthly capacity. Importantly, under this construct PacifiCorp only pays for capacity available during program hours, as measured by EnerNOC's energy monitoring technology and adjusted through a performance factor to account for those sites which opt not to participate during specific dispatch events. In order to achieve this incentive structure, interval metering was necessary. EnerNOC's equipment solution provides 5-minute interval energy monitoring as well as remote irrigation equipment control. EnerNOC's web-based portal now provides irrigators and PacifiCorp with near real-time energy usage data.

The irrigation load control program is currently available to Tariff Schedule 10 customer sites in the Rocky Mountain Power Idaho and Utah service territories. Participating sites are compensated for shutting off irrigation load for specific time periods determined by Rocky

[19] The Cadmus Group. (2013, Mar.). *Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume I* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf, page 34

Mountain Power, and are provided day-ahead notice of dispatch events. Customers always have the opportunity to opt out of (i.e., choose not to reduce load) for dispatch events as necessary for their operations. Customer incentives are based on a site's average available load during load control program hours adjusted for the number of opt outs or non-participation. The program hours are 12 to 8pm Mountain Time, Monday through Friday, and do not include holidays.

The 2013 program season ran from Monday, June 10 through Friday, August 16. Average weekly available load reduction as monitored through EnerNoc's equipment was 120.9 megawatts. There were ten load control events, each four hours in length. The Company utilized forty of the fifty-two available program event hours.

Future Actions
The agreement with EnerNoc is for 10 years. The range of individual curtailments are expected to range from 65-220 megawatts depending on participation, weather and crop conditions.

Projects 4: Distributed Resource and Renewable Resource Enhancements

These are projects related to renewable resources and distributed generation, including customer generation.

Distributed and Renewable Resources

Project Summary
PacifiCorp has significant distributed and renewable resource capacity. Renewable and non-carbon resources consist of over 25 percent of PacifiCorp's owned resources; other resource portfolio details are listed below.

Project Description
The Public Utility Commission of Oregon has recommended "an analysis of [PacifiCorp's] work integrating Distributed Generation and Renewables…, including the integration of Electric Vehicles and Solar Power". The upcoming 2015 integrated resource plan will provide a summary of the distributed resource level expected to be integrated into the PacifiCorp portfolio. The "Distributed Generation Resource Assessment for Long-Term Planning Study,"[20] which will be included as an appendix in the 2015 integrated resource plan, was developed "to project the level of distributed resources [that] customers might install". Key findings include state-by-state technical resource potential and market projections, suggesting a base case of approximately 15 megawatts of distributed generation in PacifiCorp's Oregon service area by 2020.

[20] Navigant, Inc. *Distributed Generation Resources Assessment for Long-Term Planning Study* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf

PacifiCorp has an “additional 417 [megawatts] of wind projects since the 2012 [wind integration study]”. This includes “222 [megawatts] of new wind projects that came online in 2012 in PacifiCorp’s east balancing authority”, and “195 [megawatts] of existing wind projects (Goodnoe Hills and Leaning Juniper) that were electrically moved from Bonneville Power Administration’s balancing authority area to PacifiCorp’s west balancing authority area.”[21] The 2013 integrated resource plan included an action item to update the wind integration study for the 2015 integrated resource plan, which is ongoing.

PacifiCorp has over 1,800 megawatts of owned and purchased wind resources, which includes over 1,000 megawatts of owned wind resources. Over 20 percent of PacifiCorp’s owned generating capability is made of wind, hydro, geothermal, and other non-carbon resources. These resources account for about 17 percent of PacifiCorp’s total energy output.[22] PacifiCorp owns the 2-megawatt Black Cap solar resource in Oregon, and the 34-megawatt Blundell geothermal resource in Utah.[23] Through 2013, PacifiCorp’s customers have installed over 8,000 kilowatts of solar energy through our incentive program; customers have installed an additional 2,600 kilowatts through the Energy Trust of Oregon’s solar incentives in 2013.[24]

Smart Grid Solar Energy Study

PacifiCorp performed a detailed study on a distribution circuit in Salt Lake City to determine the viability of distributed solar generation in an urban setting. The evaluation included identifying the percentage of rooftops within the study area that were viable for solar panel installations, total project cost to install the solar panels and the required metering infrastructure.

The study showed that of the 356 structures within the service area, 237 (67 percent) had rooftops capable of receiving a minimum level of solar insolation per day. Under the scenarios evaluated it was concluded that institutional buildings are estimated to have the greatest potential for installation of photovoltaic panels, followed respectively by commercial buildings, unknown land use buildings and single family residential buildings. Further, as shown in Figure 10, the study showed that the time of the maximum solar output does not coincide with the daily distribution system peak of the “Northeast 16” circuit. This illustrates that rooftop photovoltaic systems are an ineffective solution for offsetting investments towards transmission and distribution infrastructure.

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[21] *2015 Integrated Resource Plan Public Input Meeting 3*, August 7-8, 2014 [Online]. Page 71. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM03_8-7-8-2014.pdf

[22] *Our Wind Energy Resources* brochure [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Efficiency_Environment/PC_WindEnergyHandout.pdf

[23] PacifiCorp’s Renewable Resources [Online]. Available: http://www.pacificorp.com/es/re.html

[24] Pacific Power. (2014). *Oregon Conservation and Respect Report 2014* [Online]. Available: https://www.pacificpower.net/content/dam/pacificorp/doc/CCCom_Update/2014/April_2014/OR_ConservationReport.pdf

The detailed data, analysis method and results are provided in the "Smart Grid Solar Energy Study" report[25].

Smart Inverters

The Company has been actively involved in the Institute of Electrical and Electronics Engineers 1547 standard for interconnecting distributed resources with electric power systems and the California Public Utility Commission's Rule 21 working groups. These groups are currently investigating ways to adopt prudent smart inverter functionalities as standard features that would enable higher penetrations of distributed generation on U.S. utility networks. Furthermore, PacifiCorp is currently reviewing its interconnection policy for distribution systems to ensure the standards are well-aligned with the latest industry standards and that smart inverter functionalities are taken into consideration in the latest revision. The autonomous functionalities of smart inverters include, but are not limited to, the following:

- Real and reactive power support
- Dynamic var injection
- Expanded frequency trip point
- Low-voltage ride through
- Randomization of timing for trip and reconnection

The above mentioned functionalities are paramount to accommodate large-scale integration of renewables on the transmission and distribution system without adversely affecting the effective and efficient operation of PacifiCorp's electrical grid.

[25] Rocky Mountain Power. (2011). *SMART GRID Pilot Solar Energy Study* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Efficiency_Environment/Net_Metering_Customer_Generation/Smart_Grid_Pilot_Solar_Energy_Study.pdf

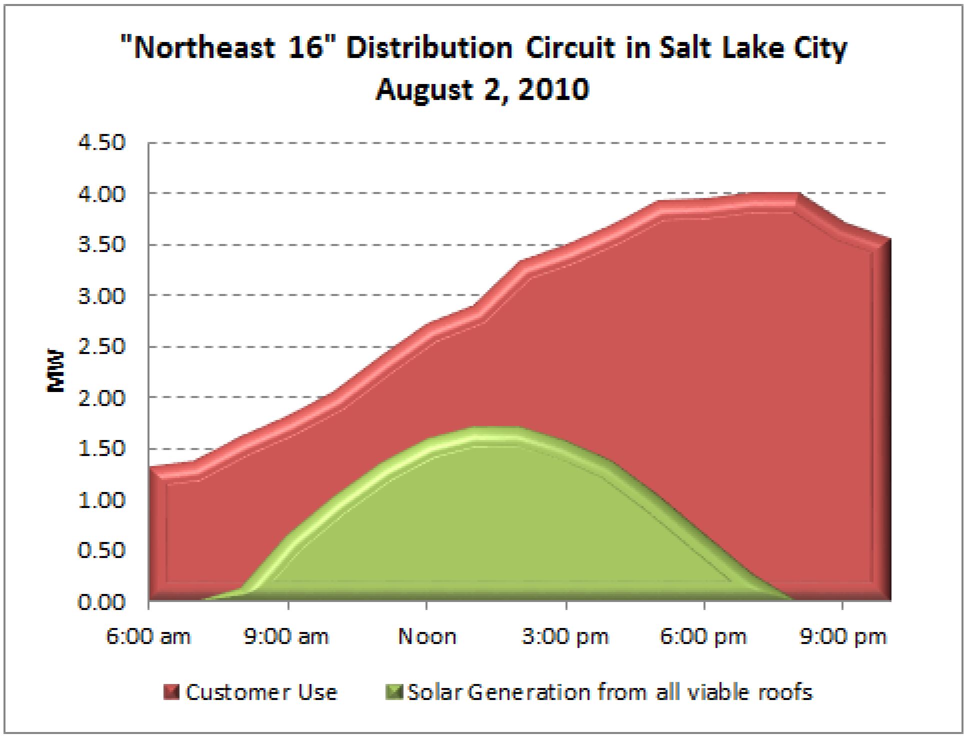

Figure 10 – Daily Peaks for Solar Energy Study

Electric Vehicles

Plug-in electric vehicles are expected to become more widespread as electric vehicle and battery technologies advance and electric vehicle purchase prices become more competitive with gasoline vehicles. It is commonly accepted that widespread adoption of plug-in electric vehicles will have a large impact on the electrical distribution system in general and distribution transformers specifically. Future battery technologies and plug-in electric vehicle enhancements may lead to utilizing plug-in electric vehicles for vehicle-to-grid, and vehicle-to-building energy supply for demand response and outage ride-through. At this time PacifiCorp expects plug-in electric vehicles to only be a new load to the system.

PacifiCorp has observed a slow growth of electric vehicles being interconnected in only a couple areas of its service territory. With the current penetration levels of electric vehicles on the grid the Company is not concerned with adverse impacts of the added load on the local distribution network.

To ensure that these vehicles do not adversely impact the distribution system, development of interoperability standards will be required along with necessary changes to electric price tariffs, electric service schedules and building codes. As large-scale introduction of electric vehicles occurs, the definition of on-peak and off-peak energy usage may change as well.

PacifiCorp began studying the effects of widespread electric vehicle penetration in 2010 by tracking electric vehicle sales, technologies and economic trends. While initially interested in the deleterious effects of increased loading on distribution transformers, the Company also took the opportunity to begin studying potential smart grid applications of electric vehicles. The results of this study have been helpful in understanding the potential growth of electric vehicles and the resulting impact on PacifiCorp's distribution network.

PacifiCorp currently expects the load growth due to the adoption of electric vehicles to be small and manageable, with large-scale deployment of electric vehicles having limited negative impact on the Company's electric grid. The Company continues to work with Clean Cities Coalitions and other entities within the service territory to facilitate public charging infrastructure development, discussions and opportunities. The electric vehicle section of the company's website has recently been updated with the latest information on the technology and infrastructure requirements to install residential, commercial and public charging stations.

The Energy Information Administration has been consistently making downward adjustments to their electric vehicle sales growth forecasts to reflect slow economic growth. For instance, in 2007 the Energy Information Administration forecast[26] suggests sales of hybrid vehicles to be about 1.4 million units sold in 2020; in 2014, that figure was revised to 510,000[27], a downgrade of over 60 percent. This downgrade is consistent for forecasts out to 2030 and indicates that the Energy Information Administration analysts are predicting a cooling of the electric vehicle market. This cooling trend may change if the national economy picks up, petroleum prices continue to rise or battery technologies continue to improve.

Vehicle-to-Grid Technology

Vehicle-to-grid technology may offer quick-response, high-value electric services to balance load. Research institutions, including the University of Delaware[28] and a consortium[29] of IBM, DTU-CET and Risoe, have demonstrated the concept. While the concept has been proven, there are many issues to overcome before adoption in power system operations and markets. In addition, vehicle-to-grid is not a necessary system in order to leverage electric vehicles which could be utilized as demand response assets.

Commercial availability of electric vehicle supply equipment and batteries robust enough to implement vehicle-to-grid technology remains scarce, even though there is a rationale and

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[26] U.S. Energy Information Administration. (2007). *Annual Energy Outlook* [Online]. Figure 52, p. 81. Available: http://www.eia.gov/forecasts/archive/aeo07/,

[27] U.S. Energy Information Administration. (2007). *Annual Energy Outlook* [Online]. Figure MT-27, p. MT-15. Available: www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf,

[28] University of Delaware. *The Grid-Integrated Vehicle with Vehicle to Grid Technology* [Online]. Available: http://www.udel.edu/V2G/

[29] Danski Energi. *The Edison Project* [Online]. Available: http://www.edison-net.dk/

economic motivation for widespread implementation. When battery costs come down enough, energy prices increase enough or technologies arise that allow electric vehicle owners to use their cars for arbitrage or emergency backup without fear of voiding warranties or the prospect of a dead car battery before their morning commute, only then will vehicle-to-grid become a viable widespread demand and frequency response tool.

The Electrification Coalition points out some of the main issues with vehicle-to-grid technology[30]:

- Applications are unlikely to appear before third or fourth generation electric vehicles evolve
- Vehicle-to-grid technology requires bidirectional chargers, which are more expensive than traditional chargers
- Software development is required by both utilities and equipment manufacturers in order to enable communication between the grid and the in-home chargers
- Researchers need to gain a better understanding of the deleterious effects on battery life when charge/discharge cycle frequency is increased

Companies such as LG Chem, EnerDel and Valence Technology that make electric vehicle and grid-tied batteries are finding it hard to stay solvent due to lower than expected demand for electric vehicles, volatility in the economy and a scarcity of investors. Without reliable battery and electric car manufacturers, utilities and other companies may find it hard to make long-term decisions concerning centralized and decentralized storage, vehicle batteries and battery-based smart grid applications. However, the demand response functionality of electric vehicles is not limited by the inverter or by battery cycling concerns.

Cost and Benefits Summary

The economics of the smart grid project was evaluated over twenty five years in order to include implementation and the twenty-year expected system life. The economics include telecommunications, hardware, and software maintenance costs, as well as transmission and distribution assets installed under this program. The costs and benefits, which are in 2014 dollars, are detailed in confidential Attachment A. The costs and benefits are escalated based on the projected inflation rate; energy savings are valued based on projected power costs.

[30] Electrification Coalition. (2009). *Electrification Roadmap* [Online]. Section 2.4.5, Vehicle to Home and Grid. Available: http://www.electrificationcoalition.org/policy/electrification-roadmap,"

Roadmap to the Smart Grid

Development of an objective roadmap must consider the economic value of individual components, the technology maturity, as well as the interdependencies. To propose an order of implementation for the smart grid roadmap the technologies were grouped into six cases, listed in Table 6. The applications for each case are clearly indicated, for example case 1 includes only an advanced metering system, case 2 includes both an advanced metering system and demand response, and case 3 includes a distribution management system and fault detection, isolation, and restoration. Figure 11 displays the net present value of each case. Case 6 includes the total costs and benefits for all components and follows the roadmap in Figure 12. All cases include the required information technology and telecommunications, as well as customer education.

Table 6 – Scenario Components

		Scenarios					
		1	**2**	**3**	**4**	**5**	**6**
Components	AMS						
	DR						
	DMS						
	FDIR						
	IVVO						
	CES						
	TSP						

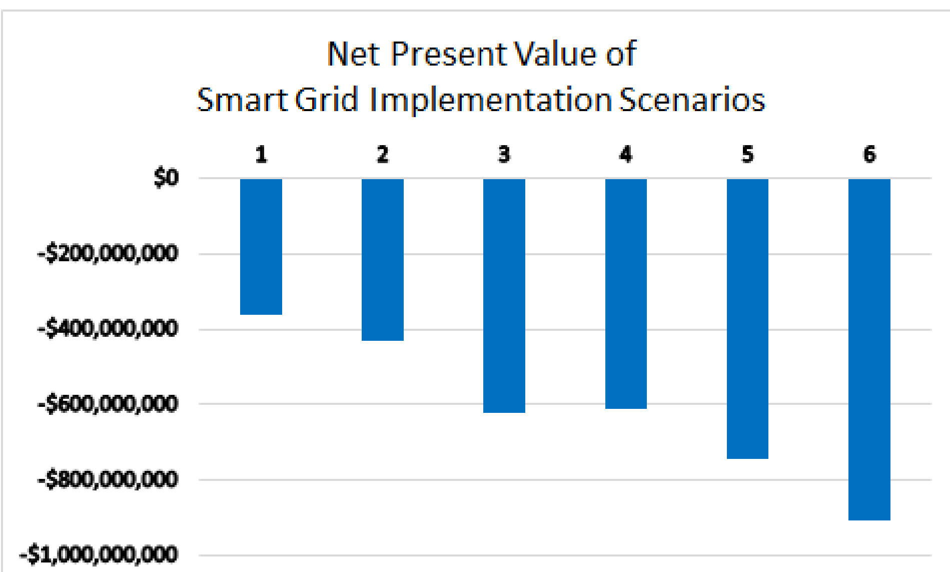

Figure 11 – Net Present Value of Smart Grid Implementation Scenarios

Each scenario generated independent costs, annual benefits, and the present value revenue requirement. No sensitivity analysis was done; costs and benefits are considered best case scenarios.

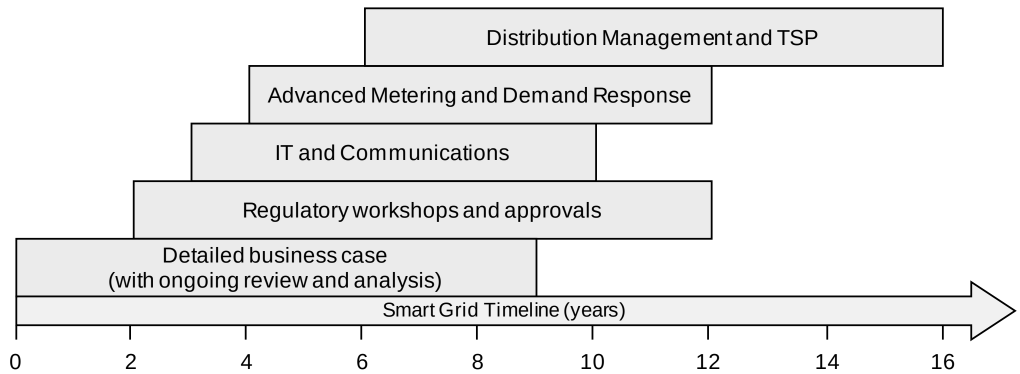

Figure 12 – Smart Grid Roadmap

Appendix A - Common Abbreviations

The electric utility industry utilizes several abbreviations that are easily confused with those used in other industries. The evolution of the smart grid has increased the number of abbreviations- as technologies emerge and continue to be refined several are used interchangeably creating confusion within the industry itself. The following table lists several of the abbreviations used in this report. Definitions, if necessary, for each will be given in the appropriate section.

Abbreviation	Name
AC	Air Conditioning
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AMS	Advanced Metering System
CAIDI	Customer Average Interruption Duration Index
CES	Centralized Energy Storage
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DLC	Direct Load Control
DLR	Dynamic Line Rating
DMS	Distribution Management System
DSM	Demand-Side Management
DR	Demand Response
FDIR	Fault Detection, Isolation, and Restoration
IVVO	Integrated Volt/Var Optimization
kW	Kilowatt
MW	Megawatt
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
TSP	Transmission Synchrophasor
WECC	Western Electricity Coordinating Council

Appendix B - Smart Grid Technologies at Other Companies

The PacifiCorp Smart Grid department researches smart grid projects around the country in order to assess technologies that may be of benefit to the Company and its customers. Listed here is a summary of the most relevant projects that the group has researched. All information here is publically available on company websites. No reviews of particular business cases have been completed on these projects.

- NV Energy, headquartered in Las Vegas, Nevada, is continuing deployment of an advanced metering system and over one million smart meters as part of their NV Energize[31] project, funded with matching funds from the American Recovery and Reinvestment Act. The NV Energy Smart Grid also includes several initiatives leading to the deployment of distribution automation, enhanced distribution and outage management and improved customer enablement.

NV Energy has completed a statewide communications network as part of its NV Energize project and is continuing the deployment of smart meters. This communications network lays the foundation for the enablement of smart meters, distribution assets and enhanced business functions. The communications infrastructure will link an advanced metering infrastructure, meter data management system and demand response management system. The advanced metering infrastructure will enable two-way communication between the utility and the smart meters that are being deployed.

Several initiatives are ongoing as part of the NV Energy roadmap, including distribution automation, enhanced distribution management, enhanced outage management, customer enablement and enhanced business intelligence. These initiatives span the 2013-2017 timeframe.

- Portland General Electric (PGE), headquartered in Portland, Oregon, has installed more than 825,000 smart meters on customers in their system. This investment has further enabled other smart grid projects, including:[32]
    - The Energy Tracker initiative, which gives customers access to their smart meter data and may help further PGE's demand-side management programs
    - Time-of-use pricing for commercial and industrial customers

[31] U.S. Department of Energy. (2012, Jun.). *NV Energy: NV Energrize* [Online]. Available: https://www.smartgrid.gov/sites/default/files/pdfs/project_desc/09-0080-nv-energy-project-description-06-08-12.pdf

[32] Portland General Electric. *Smart Grid* [Online]. Available: http://www.portlandgeneral.com/our_company/energy_strategy/smart_grid/default.aspx

PGE has also incorporated dispatchable standby generation, utilizing existing and new customer diesel backup generators, and customer generation into their system. The Salem Smart Power Project began construction on May 21, 2012 and utilizes customer generation, a 5-megawatt, 1.25-megawatt-hour lithium ion battery energy storage system and automated line switching to increase system reliability. Benefit streams include increasing supply capacity, time shifting load and firming up renewable capacity. The Salem Smart Power Project, supported by the Pacific Northwest Smart Grid Demonstration Project, creates a microgrid, which is unique in its location on distribution feeder, rather than a high-density campus.

PGE's Gales Creek project is improving uptime on a 13 kV line serving 800 rural customers. Using Cooper Power's Yukon Feeder automation system, the feeder, which has averaged 14 hours of outages per year, has experienced two successful operations since commencement of the project in December, 2011. This has resulted in 3 hours, 40 minutes of outage time avoided, markedly improving the system average interruption duration index (SAIDI) metric on the feeder. PGE is continuing to investigate distribution automation on other feeders.

- Avista, serving northern Idaho and eastern Washington (and operating with a rural, low-density customer base similar to PacifiCorp's), has invested in two smart grid projects. These projects are funded with matching grants from the American Recovery and Reinvestment Act.[33]

In Pullman, Washington, in collaboration with Batelle, Avista installed smart meters on 13,000 electric customers' homes as a smart grid demonstration project. Avista is implementing distribution automation schemes in order to automatically detect outages and more quickly restore power by isolating faulted sections of circuits. Also, customers now have access to a website that will help them track their energy usage and encourage energy efficient activities.

Avista's Spokane Smart Circuits project will impact 110,000 electric customers in the Spokane area. 59 distribution circuits and 14 substations are being upgraded to a new distribution management system with intelligent end devices. This project may help Avista decrease outage times, detect faulty equipment more quickly and regulate voltage on feeders more accurately, for an estimated savings of approximately 42,000 megawatt-hour/year. [34]

As these projects are in part funded with American Recovery and Reinvestment Act grant money their progress will be tracked on the Federal government's smart grid website[35]. The PacifiCorp smart grid team plans on continuing to watch as projects like these continue to progress, in order to learn more about best practices in the smart grid environment.

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[33] Avista. *Avista Smart Grid Projects* [Online]. Available: http://www.avistautilities.com/inside/resources/smartgrid/Pages/default.aspx

[34] Avista. *Smart Circuits Project* [Online]. Available: http://www.avistautilities.com/inside/resources/smartgrid/smartcircuits/Pages/default.aspx

[35] U.S. Department of Energy. Available: https://smartgrid.gov/

- Pacific Gas and Electric (PG&E) has installed over 9 million smart meters and is exploring the feasibility of installing 300 megawatts of compressed air storage, expending a projected $800 million to $1.25 billion in capital investments and $500 to $700 million in cumulative operating expenses over 20 years. PG&E hopes to see $600 million to $1.4 billion lower energy procurement costs; $200 to $400 million in avoided capital costs due to offsetting the need to build new power plants; $100 to $200 million in avoided operations and maintenance costs; a 10-20 percent improvement in grid reliability; and 1.4 to 2.1 million metric tons of avoided carbon emissions.[36]

The cost comes to $12-$20 per customer account, averaging $4-$7 per year per customer. Higher rates during and after smart meter installation may have been mostly coincidental with smart meter installations, but customers have nonetheless attributed some of the higher prices to the smart meter rollout. PG&E has had to increase its community outreach plan due to customer unhappiness with the smart meter program and rate increases.

On a positive note, PG&E has seen successes with its SmartAC demand response program, reducing demand by up to 575 megawatts in some cases. PG&E has plans to continue growing its automated demand response programs and looking at ways to integrate demand response and solar generation load balancing.

- Southern California Edison (SCE) has perhaps done more to advance the current state of smart grid technology and understanding than any other U.S. utility. With smart meters deployed to approximately 5 million customers and rigorous renewable portfolio standards set by the state public utility commission, SCE has some big challenges as well as opportunities in the smart grid arena.[37]

The Irvine Smart Grid Demonstration[38], which is located southeast of Los Angeles on and around the campus of University of California, Irvine, has multiple elements:

  - Energy smart customer devices, which will look at integrating home scale energy storage and photovoltaic systems in a residential environment
  - An advanced distribution system with looped circuits, integrated volt-var optimization, utility scale storage and customer generation capabilities.
  - A secure energy network linking data back to:
    - The SCE back office

[36] Pacific Gas & Electric. *Smart Grid* [Online]. Available: http://www.pge.com/safety/systemworks/electric/smartgrid/
[37] Southern California Edison. *Smart Grid Strategy & Roadmap* [Online]. Available: https://www.sce.com/NR/rdonlyres/BFA28A07-8643-4670-BD4B-215451A80C05/0/SCE_SmartGrid_Strategy_and_Roadmap.pdf
[38] U.S. Department of Energy. (2009). *Southern California Edison Company Irvine Smart Grid Demonstration* [Online]. Available: https://www.smartgrid.gov/project/southern_california_edison_company_irvine_smart_grid_demonstration

    - Various field networks
    - Customer in home smart devices

The project is taking place on two 12 kV distribution circuits, numerous residential homes and an electric vehicle charging parking lot at the University of California, Irvine campus. SCE is hoping to demonstrate zero net energy home functionality, in which over the course of the year homes will generate as much energy as they consume; reduced greenhouse gas emissions; and evaluate their smart grid implementation capabilities. Engineer design, specifications, field deployment and installation are complete. System operations, measurement, verification and reporting are ongoing through 2015.

SCE is also investing in a $55 million energy storage project in the Tehachapi Wind Resource Area in an attempt to further energy storage research and applications, in part due to the California public utility commission's recent requirement of SCE to come up with 50 megawatts of storage. Using an 8-megawatt, 32-megawatt-hour lithium-ion battery system, SCE will be measuring performance under 13 separate uses:

- Voltage support and grid stabilization
- Decreased transmission losses
- Diminished congestion
- Increased system reliability
- Deferred transmission investment
- Optimization of size and cost of renewable transmission
- System capacity
- Renewable energy integration
- Wind output shifting
- Frequency regulation
- Spin/non-spin replacement reserves
- Ramp rate
- Energy price arbitrage

The system will be operating in an area with an ultimate potential of up to 4,500 megawatts of intermittent wind power. The project, which began in 2010, is still ongoing and planned for completion in 2016. The PacifiCorp smart grid group will continue to follow the project and watch for significant advances in the energy storage field.

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Smart Grid Report on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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