e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: PacifiCorp's 2016 Smart Grid Report

COMPANY NAME: Pacific Power

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐No ☒Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

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

Report is required by: ☐OAR
☐Statute
☒Order 12-158, 13-382
☐Other

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

If yes, enter docket number: UM 1667

List applicable Key Words for this report to facilitate electronic search:
Smart Grid Report

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 1, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UM 1667—PacifiCorp's 2016 Smart Grid Report

PacifiCorp d/b/a Pacific Power submits for filing its 2016 Smart Grid Report. The report includes 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 at (503) 813-6583.

Sincerely,

RBDalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

CC: UM 1667 Service List

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.

UM 1667

Michael Breish (W)
OPUC
PO Box 2148
Salem, Oregon 97308-2148
michael.breish@state.or.us

Diane Broad (W) (C)
Oregon Department of Energy
625 Marion Street NE
Salem, Oregon 97301-3737
Diane.Broad@state.or.us

Wendy Simons (W) (C)
Oregon Department of Energy
625 Marion Street NE
Salem, Oregon 97301-3737
Wendy.simons@state.or.us

Michael T. Weirich (W) (C)
Oregon Department of Justice
1162 Court St. NE
Salem, Oregon 97301-4096
Michael.weirich@state.or.us

Renee M. France (W) (C)
Oregon Department of Justice
Natural Resources Section
1162 Court Street NE
Salem, Oregon 97301-4096
renee.m.france@doj.state.or.us

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, Oregon 97205
dockets@oregoncub.org

Robert Jenks (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, Oregon 97205
bob@oregoncub.org

Michael Goetz (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, Oregon 97205
mike@oregoncub.org

Wendy Gerlitz
NW Energy Coalition
1205 SE Flavel
Portland, Oregon 97202
Wendy@nwenergy.org

Dustin Till (W) (C)
PacifiCorp
825 NE Multnomah Street, Suite 1800
Portland, Oregon 97232
dustin.till@pacificorp.com

R. Bryce Dalley (W) (C)
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
bryce.dalley@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
oregondockets@pacificorp.com

Dated this 1st of August, 2016

Kaley McNay

Kaley McNay
Senior Coordinator, Regulatory Operations

Pacific Power Smart Grid Annual Report

August 1, 2016

Table of Contents

List of Tables

List of Figures

List of Acronyms

A/C	Air Conditioning
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AMS	Advanced Metering System
BESS	Battery Energy Storage System
CADOPS	Computer Aided Distribution Operations System
CAIDI	Customer Average Interruption Duration Index
CES	Centralized Energy Storage
CFCI	Communicating Faulted Circuit Indicators
CI	Customer Interruptions
CIS	Customer Information System
CMI	Customer Minutes Interrupted
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resources
DLC	Direct Load Control
DLR	Dynamic Line Rating
DMS	Distribution Management System
DSM	Demand-Side Management
DR	Demand Response
EIM	Energy Imbalance Market
EV	Electric Vehicle
FAN	Field Area Network
FDIR	Fault Detection, Isolation, and Restoration
FTA	Federal Transit Administration
HAN	Home Area Network
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Plan
IVVO	Integrated Volt/VAr Optimization
kW	Kilowatt
kWh	Kilowatt-hour
M&V	Movement and Verification
MDMS	Meter Data Management System
MW	Megawatt
MWh	Megawatt-hour

NERC ....North American Electric Reliability Corporation
O&M ....Operations and Maintenance
OMS ....Outage Management System
ODOE ....Oregon Department of Energy
OPUC ....Oregon Public Utilities Commission
PGE ....Portland General Electric
PMU ....Phasor Measurement Unit
PNNL ....Pacific Northwest National Laboratory
RAS ....Remedial Action Scheme
SAIDI ....System Average Interruption Duration Index
SCADA ....Supervisory Control and Data Acquisition
T&D ....Transmission and Distribution
TOU ....Time-of-Use
UL ....Underwriters Laboratories
WAN ....Wide Area Network
WECC ....Western Electricity Coordinating Council

I. Executive Summary

This 2016 Smart Grid Report (Smart Grid Report or Report) provides Pacific Power's annual update on grid modernization and smart grid initiatives and projects in response to Order No. 12-158 in docket UM 1460, and Order No. 15-050 and Order No. 15-367 in docket UM 1667.

In a coordinated effort to align corporate initiatives with industry terminology, the evolution of smart grid technology has necessitated the clarification of vocabulary to properly define existing and future projects and initiatives. 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 and processes that can be readily integrated in an affordable manner with the existing electrical grid infrastructure.

Modernization of the grid is essential to effectively implement, or overlay, smart grid technologies. While "grid modernization" projects may or may not fall under the purview of the Smart Grid Report, such projects or initiatives are considered essential to realizing a strong and robust smart grid. For this reason, PacifiCorp d/b/a Pacific Power (Pacific Power or PacifiCorp or Company) continues to focus on effective key enhancements in order to form an affordable and proven foundation for existing and future smart grid projects. Pacific Power acknowledges that traditional infrastructure solutions can be the most affordable and beneficial solution for Oregon customers and will continue with a common sense approach in implementing smart grid technologies.

A key effort at Pacific Power this past year included developing a detailed business case for Advanced Metering Infrastructure (AMI) technologies, including information technology systems that support AMI, in its Oregon service territory. Proposals were evaluated and the financial analysis indicated a positive business case. As a result, Pacific Power committed to proceed with deployment of AMI in the state of Oregon.

Other key efforts new to the state of Oregon include:

- Developing transmission synchrophasor locations and modeling criteria
- Central energy storage evaluation in conjunction with Oregon HB 2193
- Substation metering pilot program in Bend and Hood River, Oregon
- Distribution automation, e.g. Fuse Saving devices, and feasibility study
- Demand side management initiatives, e.g. irrigation load control pilot program
- Implementation of distribution system analysis application

The Company's investments in grid modernization and smart grid technologies is divided into various sections within the Report based on the impact on advanced metering infrastructure, transmission, substation, and distribution networks. A summary of projects and their status is provided in Appendix A. The Company has completed, is monitoring, or is developing grid enhancement initiatives that include:

- **Advanced Metering Infrastructure:** Network and metering infrastructure to improve customer service and provide a platform for future smart grid applications. Advanced metering infrastructure initiatives include:
  - AMI in Oregon - *Implementation in Oregon to deliver customer benefits addressing safe, affordable, reliable, and flexible service*
- **Transmission Network Enhancements:** Transmission system projects to improve grid reliability and monitoring. Transmission network enhancement initiatives include:
  - Dynamic Line Rating - *Ongoing data analysis and assessment*
  - Transmission Synchrophasor - *Model validation evaluation*
  - NERC Standard MOD-033 - *Deployment activities to meet requirement*
- **Substation Enhancement Projects:** Substation investments that increase flexibility of distributed energy resource integration. Substation enhancement initiatives include:
  - Oregon House Bill 2193 - *Evaluation of battery energy storage systems*
  - Centralized Energy Storage - *Utilization of distributed energy resource template*
  - Distribution Substation Metering - *Pilot program to enhance monitoring*
- **Distribution Automation and Reliability:** Distribution automation investments in hardware and software that enable remote or automatic configuration of the distribution network. Distribution automation and reliability initiatives include:
  - Distribution Automation Feasibility Study - *Criteria for deployment in Oregon*
  - Distribution Management - *Standard device option of Fuse Saving device*
  - Outage Management - *Bid event for recloser with bidirectional power flow*
  - Circuit Analysis Software - *Implementation of distribution system application*
- **Demand-Side Management:** Initiatives offered that allow development of direct load control and time-of-use programs. Demand-side management initiatives include:
  - Cool Keeper AC Direct Load Control - *Management of air conditioner loads*
  - Irrigation Load Control - *Pilot programs in Oregon and California*
  - Time-Based Pricing - *Lessons learned from time-of-use pilot in Oregon*
- **Distribution Network Enhancements:** Distribution system investments in technologies that improve system efficiency and distributed energy resource programs. Distributed network enhancement initiatives include:
  - IEEE 1547 Standard - *Guidelines for smart inverter implementation*
  - Oregon Senate Bill 1547 - *Development of electric vehicle infrastructure*

In addition to Pacific Power's smart grid efforts, Pacific Power remains committed to the communities we serve, providing valuable contributions to economic development, and improving the environment through operating efficiently, responsibly, and safely.

II. Staff's Recommendations for the 2016 Smart Grid Report

In response to PacifiCorp's 2015 Smart Grid Report, the Public Utility Commission of Oregon (OPUC or Commission) adopted Staff recommendations for the 2016 Smart Grid Report in Order No. 15-367, which are summarized in Table 1.

Table 1 – Summary of Order No. 15-367 Recommendations

Recommendation Description	Page(s)
1. Include a high-level table summary of all stakeholder informal comments captured at the July 12, 2016 stakeholder meeting and corresponding Company responses as an appendix in future smart grid reports.	49
2. Continue to provide updates to the Commission regarding AMI evaluation as it pertains to the Company's Oregon service territory, including status updates of necessary IT and customer systems.	9-13
3. Continue as planned to report on West-of-Populus's possible results, and if no update is available, provide a full explanation as to why that is the case.	14-17
4. Provide an update regarding the Company's use of thermal replicating relays at the Soda Springs area and any other location the Company may determine in the interim.	14-17
5. Provide analysis of specific transmission lines that PacifiCorp considers DLR as an alternative to traditional infrastructure upgrades.	14-17
6. Continue to report on any working relationship developments with WECC and Peak Reliability as well as providing comprehensive qualitative and quantitative analysis regarding the utilization of PMU data for transmission system model validation.	17
7. Provide the results of the feasibility assessment for the irrigation load control pilot under consideration for Oregon, including methodologies and both qualitative and quantitative components of the analysis.	32
8. Include a comprehensive and exhaustive evaluation of each candidate circuit discussed in the Company's reply comments, including methodologies, assumptions, and sources that identify all potential benefits and costs of CES.	20
9. Include the update on the feasibility of Fuse Saving device implementation with the accompanying methodology and qualitative and quantitative data.	26
10. Include status updates, including any benefits, of the implementation of capacitor bank, recloser, and regulator bank controls.	26-27
11. Provide a summary of ongoing efforts of completing a cost-benefit analysis of CFCIs including alternative communication technologies such as AMI.	26
12. Provide an update, including milestones, of its planned transition to a new, more powerful circuit analysis application. PacifiCorp should also provide an evaluation of the expected impact of the new circuit analysis on the potential for CVR application.	28
13. Describe how lessons learned from the irrigation TOU program can be applied to the other TOU programs offered by the Company.	35
14. Provide a quantitative and qualitative comparison of the Cool Keeper program's performance before and after the efficiency improvements.	30
15. Provide a comprehensive analysis, including methodologies, and qualitative and quantitative data of possible benefits and costs, of the Company's collaborative analysis of DER integration.	21

In an effort to continually improve the Report, Pacific Power provided a draft report to stakeholders with an opportunity to provide comments and recommendations.

The Company presented the report to stakeholders on July 12, 2016 in Salem, Oregon and requested comments be submitted by July 15, 2016. The Company received informal comments from Oregon Public Utility Commission staff and Oregon Department of Energy (ODOE).

The Company appreciates the valuable input from OPUC Staff and thoughtful comments by ODOE to produce an exhaustive and insightful report of smart grid initiatives and projects occurring throughout the Company. Informal comments received from stakeholders and Company responses are provided in Appendix B.

III. Smart Grid Strategies, Objectives, and Goals

The purpose of the Smart Grid Report is to define the philosophy and scope for Pacific Power, to deliver, develop and define the strategies, objectives, and financial characteristics required for the future roadmap, 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. 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 customers' best interests.

A. Strategies

Pacific Power considers the following strategies necessary to realizing a smart grid:

- Ensure that smart grid investments provide 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.
- Provide customers with tools and understanding to change usage for their benefit.
- Leverage broad resources at the Company's disposal, including lessons learned regarding existing analysis and work from Berkshire Hathaway Energy, comprised of four investor-owned utilities.
- Research industry projects and work with organizations, such as the National Electric Energy Testing Research and Applications Center, in order to enhance the Company's understanding of smart grid technologies.

B. Objectives

The following short-term objectives have been identified as part of the smart grid efforts at the Company.

- Increase customer awareness and understanding of how the electric system works and how electricity usage impacts and drives Company investments and operations.
- Enhance the meter data management system implemented to become a scalable future smart grid data throughput platform, targeting completion by Q1 2017.
- Continually improve customer relations through customer communications and web portal work.
- Provide customers with tools that may be used to change their electricity usage for their benefit.

- Optimize the Company's electric system through the application of cost-effective smart grid technologies.

C. Goals

By implementing the objectives mentioned above, the Company is on track to achieve the following smart grid goals established by OPUC under Order No. 12-158[1]:

- Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network.
- Enhance customer service and lower the cost of utility operation.
- Enhance the ability to save energy and reduce peak demand.
- Enhance the ability to develop renewable resources and distributed generation.

The Company seeks to leverage smart grid technologies to optimize the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers. This overall goal aligns 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 the total cost of ownership, performing well-researched cost-benefit analyses, and focusing on customer outreach.

[1] Docket No. UM 1460, May 8, 2012. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15928

IV. Projects Overview

The Company has implemented a number of grid modernization and smart grid-related projects and programs. Section V describes the individual projects, programs, and efforts in detail. These are displayed spatially in Figure 1. These projects are chosen based on analysis of their ability to cost-effectively improve service to customers. While these projects are located throughout the Company's service territory, lessons learned through positive business case analyses will apply to the Oregon power system. These projects can apply to any sector of the power system, which synergistically support the smart grid concept as depicted in Figure 2.

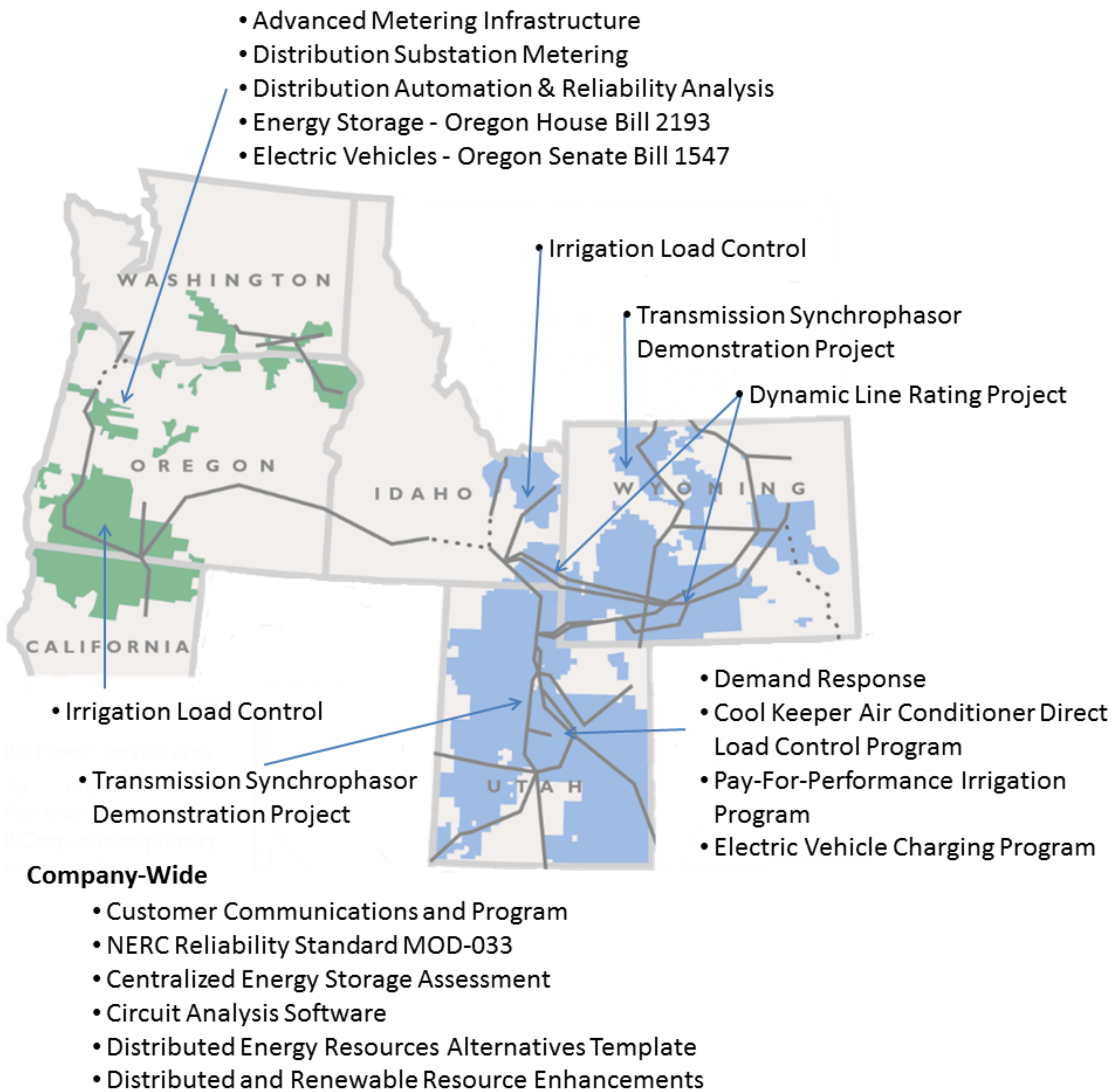


Figure 1 – PacifiCorp Grid Modernization Projects

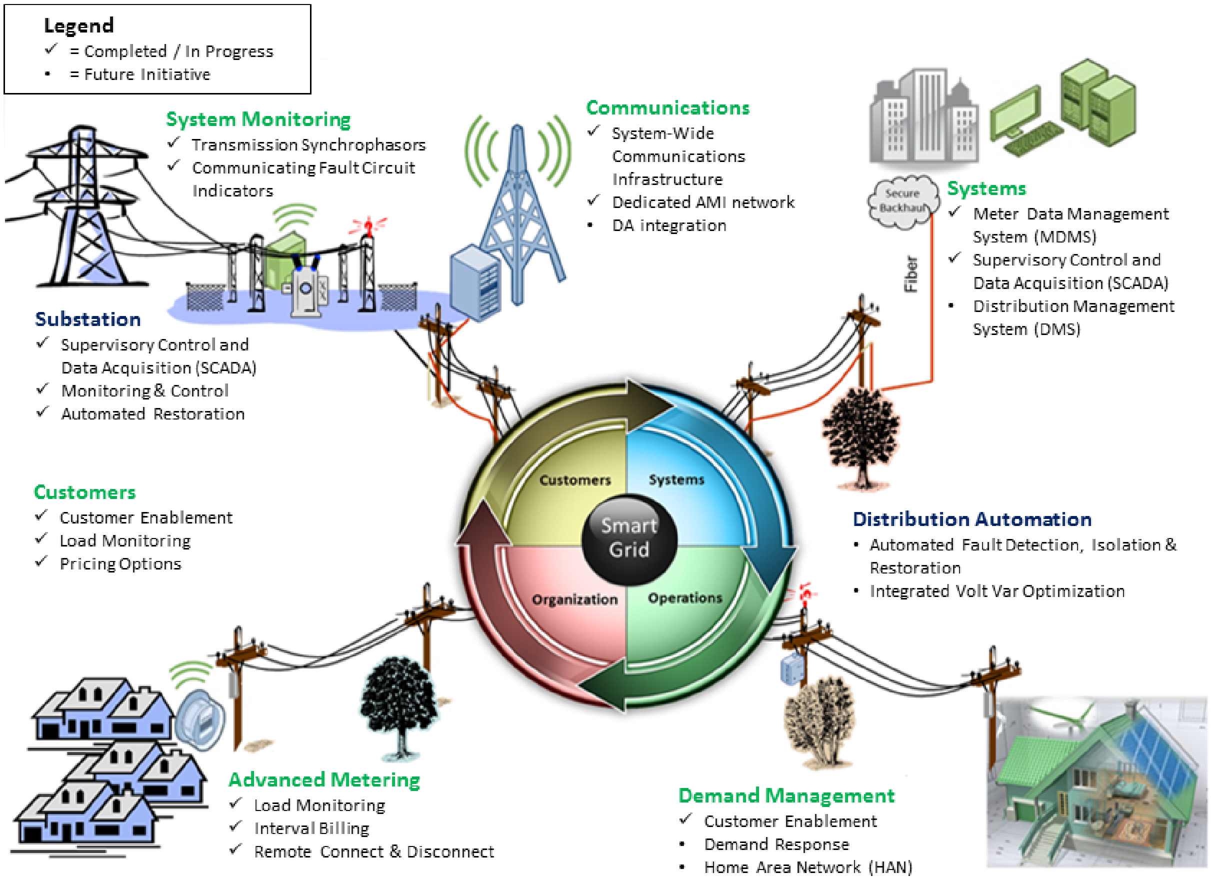


Figure 2 – Select Smart Grid Components

Many of the smart grid technologies are dependent upon preceding technology deployment for the full benefit. The Oregon AMI network is an essential component of the field area network that will enable future utilization of smart grid technologies by establishing a communication backbone.

V. Status of Grid Modernization and Smart Grid Investments

A. Advanced Metering Infrastructure and Customer Communications

1. Advanced Metering Infrastructure Background

Over 60 million smart meters have been deployed in the U.S. over the last ten years. Pacific Power's decision in early 2016 to install two-way Advanced Metering Infrastructure (AMI) in Oregon benefits from the lessons learned from earlier deployments, technology advancements and cost reductions.

The Company has installed and operated 1.2 million Automated Meter Reading (AMR) meters in its Utah, Wyoming, and Washington service territories. The AMR installations have been successful in reducing meter reading costs, reducing meter energy losses, improving employee safety, and increasing the overall quality of service to customers.

Pacific Power conducted research with other utilities to capture lessons learned from early adopters of AMI from a cost, benefit and risk mitigation standpoint (specifically, First Energy, Pacific Gas and Electric, NV Energy and Portland General Electric). In addition, a request for information (RFI) was conducted with major vendors focused on evaluating advancements in technology and reviewing actual benefits obtained by other utilities. The RFI was followed by a formal request for proposals (RFP) that resulted in price reductions that coupled with increasing O&M labor rates resulted in a positive business case to implement AMI in Oregon.

2. Oregon AMI Project

The OPUC has expressed its general support for Pacific Power implementation of AMI. On November 13, 2015, the OPUC adopted Staff's recommendation for the company to keep the OPUC apprised of new developments related to AMI evaluation, including status updates of necessary IT and customer systems. On April 6, 2016, the Company filed a letter with OPUC[2] and notified union leadership and employees concerning the Company's plans to install AMI in Oregon in 2016 through 2019. On April 8, 2016, the Company announced its intentions to install smart meter assets through a press release, created a website[3], and published printed materials.

[2] PacifiCorp's Advanced Metering Infrastructure Update, Docket No. UM 1667. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=18500
[3] Oregon Smart Meters. *Pacific Power* [Online]. Available: https://www.pacificpower.net/ya/kyb/oregon-smart-meters.html

Project Summary

The AMI program involves replacing existing customer meters with smart meters and installing a comprehensive advanced metering system. This system includes the technology and telecommunications network infrastructure necessary for the Company to remotely read and operate customer meters.

Pacific Power's Oregon AMI investment will deliver reduced O&M expenses through reduction of labor, additional revenue through reduction of power losses and write-offs, as well as provide the following customer benefits to continue supporting its commitment to safe, affordable, reliable, and flexible service:

- Cost savings over the life of the investment
- Improved customer service
    - Customer energy consumption information available via web portal
    - Improved bill accuracy, fewer estimated bills
    - Improved response time for connection of service
    - Allows customers to manage energy usage
    - Improved resolution of high bill complaints
    - Faster outage and restoration notification through remote meter communication
    - Fewer visits to the meter location; not required to be on customer property
- Aids future rate design that gives customers rate plan options to include applications related to net metering, electric vehicles, and dynamic pricing programs
- Provides platform that can be leveraged for future Smart Grid applications such as distribution automation
- More data and information to manage the network for system operations efficiently
- Improved worker safety through less traveling and remote access to meter for troubleshooting
- Environmental: CO_2 reductions due to less vehicles on the road

Project Description and Analysis

Pacific Power's Oregon AMI implementation will establish wireless connectivity between the Company and its Oregon customers that eliminates the need to physically visit meters in order to gather consumption data and connect or disconnect electric service. Smart meters send interval meter reads to a central collection point, which are then backhauled to the energy company for billing and customer presentation purposes. Rather than only receive one bill per month with usage data, customers will have access to their hourly consumption data through a web portal the day after it is metered. Access to near real time data enables customers to quantify the results of their energy decisions before and after the fact and feel as though they have more control over their electric energy usage.

Pacific Power's Oregon AMI implementation will enable the following functionality:

- Provide a web portal that allows customers to monitor and manage energy consumption
- Capture hourly meter reading data remotely
- Perform on-demand meter reads
- Turn customer's power on and off remotely
- Verify if a customer's service is on for isolated customer outage inquiries by pinging the meter
- Collect and analyze voltage, power quality, tampering, and system data
- Remotely reprogram meters

A representation of the AMI technology that will be implemented is shown in Figure 3.

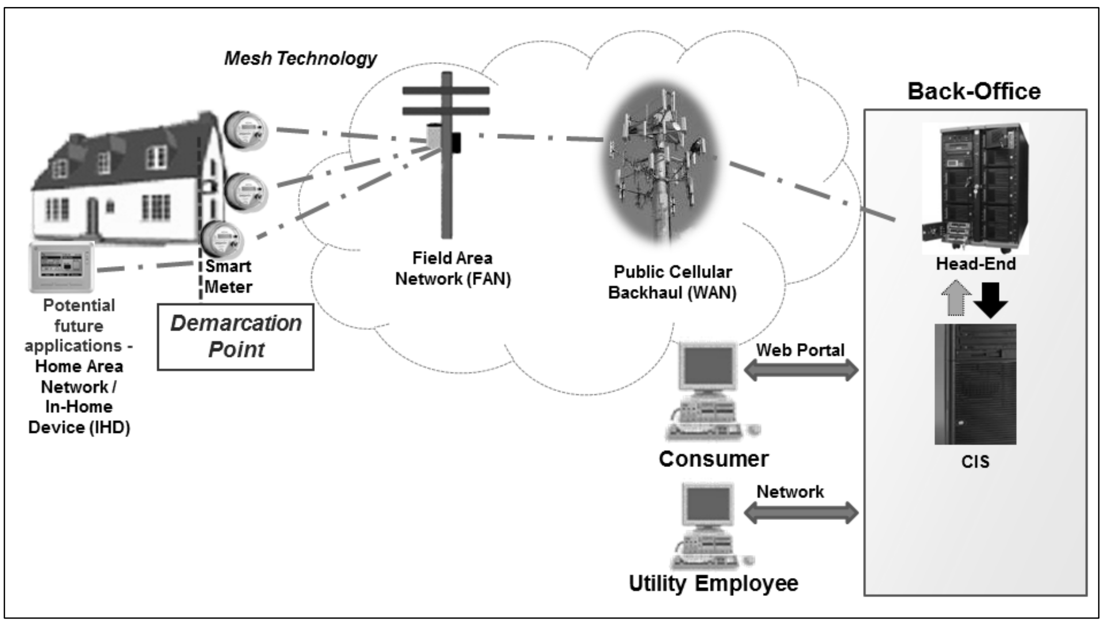


Figure 3 – Representation of AMI technology to be deployed in Oregon.

The key components in the AMI network include smart meters, the communications network, and related software/IT systems.

Electronic AMI meters will be installed for approximately 590,000 Oregon customers (excluding opt-out customers or specified commercial meters), which will contain two-way communication modules that provide near real-time capabilities. Most residential and small commercial meters will contain a disconnect device within the meter which will allow remote connect/disconnect capabilities. All meters will store usage data, event monitoring, voltage/power quality data, tampering events, and other meter/system information.

Hierarchical communications networks are needed to manage the large volume of data anticipated on the AMI network. Core components of the communication network include:

Meter Test Lab Network – The Meter Test Lab will enable the validation of the configuration, capabilities, and limitations of the vendor's AMI solution, thereby influencing the overall design and additional solutions that may need to be delivered. It will provide an isolated environment where real-world use cases (such as meter failure or communication network performance) can be conducted, studied and solutions designed to address use cases. Additionally, it will form the basis for the production systems to be constructed and configured, such as the core network, AMI head-end and meter data management system. After go-live of the project the meter test lab will provide the capability for all meter, communication nodes and system configurations, firmware upgrades and patches to be fully qualified prior to their release to production systems and the field assets.

Core Network (IPv6) – A core network will be built that interconnects production servers, workstations, and storage. The core network connectivity further extends to field located data collectors and meters. It also connects to the corporate network for other production assets.

Field Area Network (FAN) – The field network will wirelessly interconnect meters to neighborhood data collectors. Each data collector will consolidate and manage data traffic, which will be routed back to the AMI core network.

Backhaul – Wide Area Network (WAN) – Cellular carrier data services will be used to route traffic between the FAN data collectors and the core network.

The implementation of an AMI system requires the introduction of new computing assets and modifications to existing applications and services. The following outlines the software/IT systems required for AMI:

- **Head-End Metering Collections System –** The head-end system is hardware and software that provides the interface between the metering system, and energy company processes (such as meter data management and billing).
- **Meter Data Management System (MDMS) –** A MDMS collects and stores meter data from a head-end system and processes that meter data into information that can be used by other energy company applications including billing and customer information systems. The existing MDMS installed for EIM will be utilized for the AMI system.
- **Customer Portal –** A web-based solution that provides customers with usage and billing information. It also gives internal users the information and tools they need to better respond to and resolve customer billing inquiries.

Future Actions and Timeline

The following items are outside the scope of the Oregon AMI project but the system will be installed with consideration that these additional applications may be pursued in the future:

- Integration with the CADOPS outage management system.
- Critical peak pricing or prepaid pricing capabilities.
- Limited tariff billing functionality aimed primarily at distributed energy generation.
- Integration with the SCADA and DMS systems.
- Functionality that provides customer data to a home area network (HAN).
- Capability to automate interactive volt/VAr optimization (IVVO).
- Various distribution automation capabilities (DA).
- Demand-side management (DSM) functionality and programs.
- Load planning capabilities and integration.

The Company has scoped and acquired an AMI system with the expectation that future deployment of this entire list of applications is feasible. However, some applications listed above are dependent on other systems in order to be implemented. For instance, critical peak pricing or prepaid pricing capabilities will require evaluation and possible upgrade of the Company’s customer information system (CIS) to handle the required additional functionality. The Company will continue to develop business cases for each application to determine their value and priority based on potential benefits to the customer.

A summary of the anticipated project timeline is shown in Table 2 below.

Table 2 – Anticipated AMI Project Timeline

Stage	Timeline	Activity
IT & Network Design	Q2 2016 – Q4 2016	AMI Lab Environment, Technical Design, Communication Network Design, Customer Portal Development
IT & Network Implementation	Q3 2016 – Q4 2017	Build phase of IT & Network AMI infrastructure for the core functions. Including testing of systems and integration.
Training	Q3 2017 – Q1 2018	System training for support, Field, and Call Center employees
Meter Installation	Q1 2018 – Q4 2019	Conduct meter exchange deployment across Oregon service territory
Project Close	Q4 2019	Project evaluation and final documentation

3. Oregon AMI Customer Communications and Programs

A web-based customer portal that provides customers with usage and billing information will be introduced as a component of Pacific Power's Oregon AMI project. The portal is anticipated to allow customers to monitor and manage energy consumption utilizing near real-time usage measurements. Additional communication materials will be disseminated throughout the project to educate customers about upcoming changes.

B. Transmission Network and Operations Enhancements

1. Dynamic Line Rating Background

Dynamic line rating (DLR) systems utilize sensors to monitor the conditions that impact the real-time temperature of a transmission line or lines, and use this measured data to calculate the real-time thermal capability of the lines. Transmission lines are rated utilizing anticipated conductor temperatures, which are based on line loading and assumptions of worst-case ambient weather conditions for a given season (for example, the hottest anticipated summer day with the lowest anticipated wind speed). Since line loading is the primary driver of conductor heating, these ratings allow utilities to safely operate their systems through changing weather conditions. However, as worst-case loading conditions approach thermal limits, favorable ambient weather conditions may supply some margin for thermal capacity increase beyond the static rating, which is based on worst-case ambient weather conditions. Dynamic line rating systems allow utilities to utilize this available thermal capacity.

PacifiCorp Transmission is also evaluating a related technology known as thermal replicating relays. These devices monitor the thermal properties of the line, and if these devices sense the conductor thermal limits are being exceeded, they send a trip signal to open the line. Under NERC standard PRC-023, transmission lines meeting a certain criteria are required to have thermal trip settings equal to 150% of their emergency winter rating. This setting requirement enables manual emergency remedial action during contingency outages to prevent cascading outages, but can put the line at risk for conductor damage. PRC-023 allows thermal replicating relaying to be installed as an exception to this practice where line tripping will not cause cascading outages, thus eliminating the risk of conductor damage and associated repair costs.

Dynamic Line Rating Project Summary

Two dynamic line rating (DLR) projects were implemented in 2014 and a third thermal replicating relay project will be evaluated during 2016.

The first DLR project, the Minors-Platte line project, is complete and the rating of the line has been modified to reflect the correlation between wind generation in the area and the cooling effects of wind on the line. The second DLR project, the West-of-Populus project, is currently being monitored for effectiveness and application to real-time operations.

The Company is investigating the third project, the use of thermal replicating relaying devices in the Soda Springs area of Idaho. The loss of two transmission lines in this area would overload a third line until remedial action is taken.

Project Description and Analysis

West-of-Populus DLR Project

The West-of-Populus location is comprised of three 345 kV transmission lines west of Populus substation in southeast Idaho with a combined length of 147 miles. In 2013, the West-of-Populus location was identified as needing transmission expansion during the Company'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.

The Company selected the CAT-1 line monitoring system offered by The Valley Group for the project. 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 is then communicated via radio to a central master station. The 345 kV transmission system near Populus substation is shown in Figure 4, where the West-of-Populus DLR system was installed.

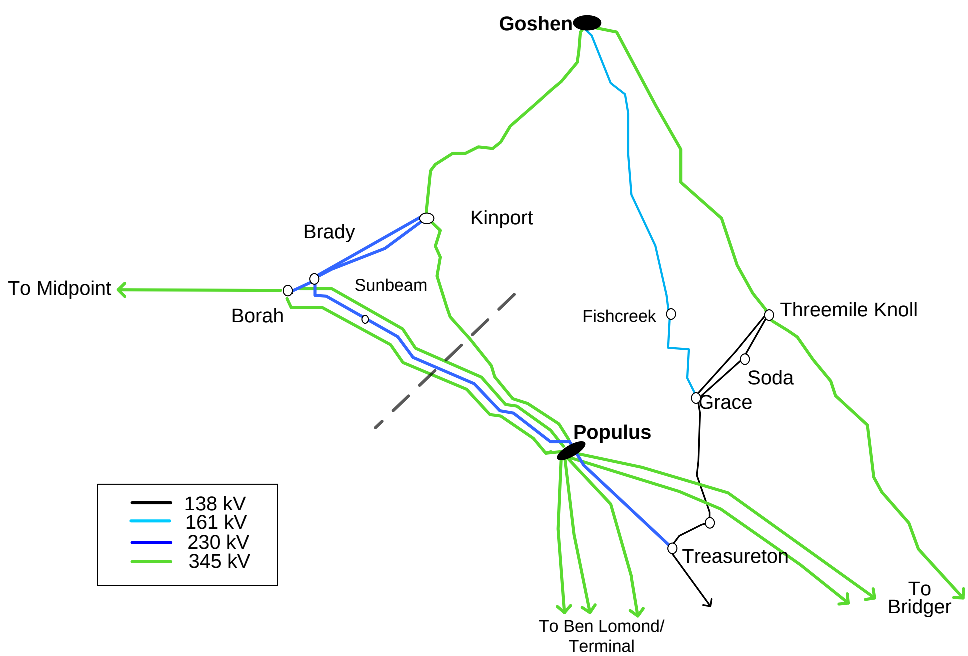


Figure 4 – Simplified Transmission System near Populus Substation.

The DLR installation on the 345 kV West-of-Populus path is producing data for PacifiCorp grid operations. Processing this data is ongoing and remains inconclusive due to the actual line loading not having approached the thermal capacity of the line and no clear correlation between the dynamic line rating, conductor temperature and the loading levels is apparent. Appendix C demonstrates a fluctuating conductor temperature; however, the fluctuation clearly is being influenced by the ambient nighttime and daytime temperatures more than the line loading, which is typically the primary driver of conductor temperature. Because low and fairly consistent loading levels are having very little effect on the temperature fluctuation of the line, there are periods of increasing load but decreasing or steady conductor temperatures. The dynamic line rating system is expecting conductor temperature to increase with line loading, and when the inverse occurs the system calculates irregular line ratings. Given these irregularities associated with the low loading levels experienced over the last year, it is difficult to draw a conclusion on the effectiveness of dynamic line rating for the West-of-Populus lines.

Thermal Replicating Relay Evaluation

Thermal replicating relays were investigated for installation in conjunction with a DLR system on the Grace-Soda-Threemile Knoll 138 kV line. The thermal replicating relays would monitor the current flow on the Grace-Soda-Threemile Knoll 138 kV line when the Grace-Threemile Knoll 138 kV line is out of service. The relays would trigger to open the circuit breaker at Soda substation and the associated Grace-Soda-Threemile Knoll 138 kV line if the line overloads to 100% of its emergency rating calculated by a DLR system. Opening the line avoids a prolonged overload condition which would cause conductor damage and associated repair costs.

As both the Grace-Soda 138 kV and Soda-Threemile Knoll 138 kV lines are parts of the PRC-023 list, the thermal relays combined with a DLR system was proposed instead of generic overload protection. The thermal replicating relays operating to trip the circuit breaker at Soda substation would sectionalize the Goshen-Soda 138 kV line and Soda-Threemile Knoll 138 kV line without tripping any generation or load. The cost of the thermal replicating relaying, along with the DLR system was approximately $1.4 million.

As part of this evaluation, an alternative to thermal replicating relays, a Remedial Action Scheme (RAS) in the form of redundant relays could be installed to trip the circuit breaker at the Soda 138 kV switch yard if the Soda-Threemile Knoll 138 kV line or Soda-Grace 138 kV line overloads to 100% of its emergency rating. The cost of the RAS alternative was determined to be $115,000. Due to the cost advantage for customers, the Company will move forward with the RAS solution.

Future Actions and Timeline

West-of-Populus DLR Project

PacifiCorp Transmission will continue to monitor line loading on the West-of-Populus path. When line loading increases due to outage contingencies or high flow scenarios, PacifiCorp Transmission expects to see a better correlation between line temperature and line loading. Higher line loading will provide a better opportunity to draw conclusions on the effectiveness of the dynamic line rating.

Dynamic Line Rating and Thermal Replicating Relays

PacifiCorp Transmission will continue to look for transmission constraints and other opportunities where dynamic line rating and/or thermal replicating relays may be viable solutions. As constraints are identified through ongoing transmission planning on the PacifiCorp's transmission system, and dynamic line rating is deemed a viable alternative solution, further evaluation will be provided in future smart grid reports.

2. Transmission Synchrophasor Demonstration Project

Transmission synchrophasors, also called phasor measurement units (PMUs), can lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement. The PMU can also be used to increase reliability by synchrophasor-assisted protection for real-time measurement of multiple remote points on the grid at 48 samples per second.

The benefits of synchrophasor installation and intelligent monitoring of the transmission system are focused on increased visibility and reliability.

Project Summary

The Company and other participating energy companies have installed eight PMUs at eight substations and have been streaming data to WECC since 2013. Peak Reliability is continuing to develop data access through a web interface for energy company participants.

Project Description and Analysis

PacifiCorp Transmission participated in the WECC Western Interconnection Synchrophasor Project,[4] a collaborative effort among partners throughout the U.S.

[4] 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

portion of the Western Interconnection. The project supported WECC and Peak Reliability to maintain the stability of the power system. The synchrophasors are being used by Peak Reliability and partners to identify and analyze system vulnerabilities and disturbances on the western bulk electric system and take timely actions to avoid widespread system blackouts.

PacifiCorp Transmission and other participating utilities take part in monthly synchrophasor performance and data quality meetings hosted by Peak Reliability to ensure the data integrity of the PMUs and track ongoing development of Peak Reliability's website. Peak Reliability implemented two sections on its website to ease energy company contribution in PMU data utilization: the Model Registry[5] for verification of model settings and points, and the Synchrophasor Registry[6] for access to PMU measurements.

In conjunction with developing access to data, collaboration within the Company to improve real-time situational awareness for transmission operations has been to ensure the newly installed SCADA Monarch energy management system is capable of integrating PMU data. Once access to data is secured, further discussions within the Company regarding the feasibility and value of integrating PMU data into operations will occur.

Future Actions and Timeline

Confirmation and verification of data point configuration within the Model Registry is ongoing, with an anticipated completion by Q4 2016. Data measurements for past events should be available to participating utilities for download through the Synchrophasor Registry web interface by Q1 2017.

3. NERC Reliability Standard MOD-033

The Steady-State and Dynamic System Model Validation standard, also called NERC Reliability Standard MOD-033[7], is a new model validation standard proposed to establish consistent validation requirements to facilitate collecting accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

[5] Peak Reliability. *Peak Reliability: Model Registry* [Online]. Available: https://www.peakrc.org/Model/Pages/Registry.aspx
[6] Peak Reliability. *Peak Reliability: Synchrophasor Registry* [Online]. Available: https://www.peakrc.org/synchrophasor/Pages/default.aspx
[7] NERC. *NERC: Project 2010-03 Modeling Data (MOD B)* [Online]. Available:- http://www.nerc.com/pa/Stand/Pages/Project2010-03ModelingData(MOD-B).aspx

Project Description

Measurement data originating from PMUs will be necessary in order to satisfy the validation requirements expressed in MOD-033. The Company has determined locations throughout its service territory necessary for such data to be collected and is in the process of identifying existing equipment capabilities at selected locations. Locations determined throughout the Company's service territory are based on criteria outlined in standard PRC-002[8] and are provided in Appendix D. Additional locations may be requested to satisfy MOD-033 requirements. Equipment deemed inadequate to provide required measurements may be upgraded, on a site-by-site basis.

Model validation procedures are also being evaluated, in conjunction with data and equipment availability, to fulfill MOD-033 requirements. Creation of a documented process to validate data that includes the comparison of a planning power flow model to actual system behavior and the comparison of the planning dynamic model to actual system response is ongoing. Appendix E illustrates the validation analysis utilizing sample data between two separate models and the actual PMU data.

Future Actions and Timeline

PacifiCorp Transmission is planning to meet necessary requirements set forth by MOD-033, before the standard effective date of May 1, 2017. This project is only in its initial stages of gathering information and assessing feasibility. While likely locations for PMU installations have been identified, equipment and communication needs have not been scoped and therefore a cost estimate for this project is not available at this time. The Company anticipates a scope and estimate will be available for the 2017 Report.

C. Substation Operations Enhancements

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

Centralized energy storage (CES) includes but is not limited to 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

[8] Standard PRC-002-NPCC-01 – Disturbance Monitoring. *NERC Reliability Standards* [Online]. Available: http://www.nerc.com/files/PRC-002-NPCC-01.pdf

and has high opportunity costs when generation is decreased. Providing service to the electrical grid becomes progressively more challenging as the amount of the grid's energy requirements are increasingly served from these intermittent resources. Two methods to fill this generation gap without the use of dispatchable resources are demand response (DR) programs and centralized and/or localized energy storage.

1. Oregon House Bill 2193

Project Summary

In Oregon, Pacific Power is evaluating battery energy storage systems (BESS) to meet the requirements set forth by Oregon House Bill 2193 (HB 2193). The qualifying BESS should have the capacity to store at least 5 MWh of energy.

Project Description and Analysis

Pacific Power is actively participating in the development of OPUC guidelines for implementing an energy storage program pursuant to HB 2193 that directs electric companies in Oregon to procure one or more energy storage systems that have the capacity to store no less than 5 MWh. On May 9, 2016, the Company, along with PGE and interested parties, presented their progress to meet requirements of the initiative[9]. Suggestions to the OPUC for guidelines to critique applications were also presented.

Future Actions and Timeline

Pacific Power will continue to evaluate energy storage for future resource and system needs, and to work with OPUC on implementing an energy storage system to meet guidelines outlined in HB 2193.

2. Centralized Energy Storage Assessment

Reporting recommendation eight states Pacific Power should "include a comprehensive and exhaustive evaluation of each candidate circuit discussed in the Company's reply comments, including methodologies, assumptions, and sources that identify all potential benefits and costs of CES." A phone call between Staff and Pacific Power occurred on November 30, 2015 to clarify requirements set forth for the 2016 Report. As part of the clarification request regarding Staff recommendations[10], Staff provided the following response:

> *Staff clarifies that it was referring to the three "studies" conducted by PacifiCorp, NV Energy, and MidAmerican Energy that are mentioned on the*

[9] Docket UM 1751, May 12, 2016. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19733

[10] "Staff Reponses to PAC Clarification Requests," received from Staff on February 24, 2016.

bottom of page 19 of the Company's reply comments. The Company indicated during the Nov. 30, 2015 phone call that it would provide the PacifiCorp study in the interim, which Staff finds sufficient.

The Company's study of the potential use of DER to offset or defer a power transformer replacement project in Moab, Utah, will be provided to Staff[11].

3. Distributed Energy Resources Template Deployment

Pacific Power has recognized the role that distributed energy resources (DER) may play in the deferral or offset of traditional poles and wires infrastructure investments. To that end, the Company commissioned an internal study and report[12] investigating the potential use of DER to offset or defer a power transformer replacement project in Moab, Utah. One of the outcomes of the report was the recognition of a need for a tool for transmission and distribution planners to utilize in comparing alternative DERs solutions to traditional solutions.

Project Summary

Create a tool that can be used by transmission and distribution planners to screen system issues and quantify the feasibility and affordability of a DER alternative solution in comparison to traditional solutions.

Project Description and Analysis

A DER alternatives template was created in a Berkshire Hathaway Energy cross-platform initiative that, given a few input parameters common to traditional solution analysis and solar data, provides a feasibility assessment and cost comparison for solar, battery storage, and demand response solutions. The screening tool utilizes input parameters such as hourly facility load data, annual solar data obtained from National Renewable Energy Laboratory's (NREL) PVWatts Calculator[13] and cost estimates for battery storage and demand response solutions.

Costs in the alternatives template for solar installations are based off the results of recent requests for proposals at Rocky Mountain Power and NV Energy. Costs for battery storage are based off studies performed by an external contractor to inform the IRP process. A new study has been commissioned to refresh the battery storage costs and results are expected by the end of 2016. Once results are finalized, costs will be updated in the DER alternatives template.

[11] "DER Pilot Study Report", to be submitted to Oregon PUC staff.
[12] *Id*.
[13] NREL's PVWatts Calculator. *National Renewable Energy Laboratory* [Online]. Available: http://pvwatts.nrel.gov/

The template has been deployed to area transmission and distribution planners throughout the Company through a series of training sessions that began in February 2016 and ended in May 2016. An example template is provided in Appendix F.

Future Actions and Timeline

It is anticipated that for future budget cycles, proposed system reinforcements will include DER solutions as part of the analysis and their documentation proposals. Where feasible and the most affordable option, DER solutions will supplant traditional solutions for implementation.

4. Redmond Circuit Analysis

Project Description, and Analysis

In 2016, the Redmond 5D22 circuit in Redmond, Oregon was identified as a potential candidate for installation of an energy storage device to rectify low voltage issues projected to occur in 2019 due to load growth and relatively high loading levels. The circuit already functions with three line regulators in series, not including the substation regulators. The load center of the circuit is located several miles from the substation. Both issues increase the difficulty of controlling voltage and thus present an opportunity for an innovative solution.

An analysis was performed utilizing the DER template to determine the feasibility and estimated cost of a DER solution. The analysis is provided in Appendix F. The only feasible DER alternative to resolve the voltage issue is the installation of an energy storage device with an estimated cost of $2.2 million.

Future Actions and Timelines

Further investigation into the voltage issues on Redmond 5D22 shows that a load balancing and load transfer project can solve the voltage issues through the five year planning horizon. Due to the low cost of a traditional solution, the DER alternative solution will not be implemented at this time. However, given the temporary nature of the proposed traditional solution and the complexity of the voltage issue, the Redmond 5D22 circuit will continue to be evaluated as a potential candidate for energy storage and may satisfy the guidelines of HB 2193.

5. Distribution Substation Metering

Substation monitoring and measurement of various electrical quantities is seen as a necessity due to growing levels of distributed energy resources. Enhanced monitoring helps to resolve the following challenges:

- Limited visibility on loading levels, load shape, and event information required to develop thorough interconnection studies, determining safe switching procedures, and cost effective capital improvement plans.
- Single-phase DER have the ability to exacerbate load imbalance on a distribution circuit, and increases the potential for unintended circuit breaker operations from elevated neutral currents.
- The growing interaction of DER on distribution system equipment has potentially detrimental impacts on transient and steady-state voltage levels. Understanding the production levels of DER on a distribution circuit should allow for the accurate determination of effective grounding requirements and fault clearing control schemes. These systems, if not appropriately installed, can result in temporary overvoltages to customers or leave circuits improperly protected during fault conditions.
- Potential harmonic issues from inverter-based DER can result in customer motor damage and interfere with high-frequency communications.
- The necessity for measurement of per-phase vector quantities to improve optimization opportunities for capital costs and system losses.

Project Summary, Description, and Analysis

Pacific Power plans to deploy an advanced substation metering pilot that includes installing advanced meters at distribution substations that have no existing communications. Remote communication paths will be installed with all meters. A data management and analytical tool will be purchased to automatically collect, analyze, interpret and report on available data.

SCADA has been the preferable form of gathering load profile data from distribution circuits, however SCADA systems can be expensive to install and additional equipment is required to provide the data needed to perform analysis on harmonics issues. The advanced metering pilot may prove to provide an affordable option for gathering requisite substation data.

Project Description and Analysis

- Purchase and install advanced substation meters at distribution substations with limited or no communications.
- Ensure all substation meters installed as part of this program are enabled with remote communication capabilities.
- Implement a data management system to automatically download, analyze and interpret data downloaded from all installed substation meters.
- Develop a process to ensure all data collected is used to improve the interconnection study process in addition to improving long-term and short-term distribution and transmission planning studies.

Future Actions

Pacific Power has selected an advanced substation meter based on the requirements listed in Appendix G and is in the process of evaluating locations for the pilot program. Preliminary analysis indicates the Powell Butte substation in Bend, Oregon and the Kenwood substation in Hood River, Oregon as potential areas for the pilot due to increasing DER interconnection applications in the district. A data management system is also under evaluation. It is anticipated the advanced meters will be installed, and the data management system will be gathering data by Q1 2017.

The cost to install an advanced substation meter is estimated to be $15,000 for this pilot with ongoing cellular data costs of $20 per month. Typical SCADA installations cost $100,000 or more, depending on the site location and availability of nearby compatible communication networks.

Based on the success of the pilot installation, additional meters will be installed as needed to address increasing DER penetration issues.

6. Oregon State University Energy Storage Demonstration Project

Pacific Power offered its support as a Committed Utility Partner to Oregon State University (OSU) for OSU proposal 16-0565, in support of OSU's application to Oregon Department of Energy RFGA #330-1186-15 (ODOE #15-013).

Oregon State University proposed building a new data center on campus. This proposed energy storage project would have provided a variety of benefits to the OSU data center, OSU electrical engineering research staff and students, and the Company. The core activity of this project would have involved the installation and evaluation of multiple use cases of a containerized, grid-attached 250 kW, 1 MWh vanadium flow battery energy storage system provided by Imergy Inc. The energy storage system would have provided a key resource for improving the reliability and resilience of the OSU data center to survive power outages related to storms or other natural disasters. In addition, the facility associated with the data center would have provided a powered, safe zone for students during a lengthy power outage. The close proximity of an operational 1.5 MW solar array on the same energy company distribution feeder as the data center would have allowed OSU to better manage the power quality and optimize the volt/VAr profile of the feeder.

However, OSU proposal 16-0565 was not selected primarily due to a significant funding gap between the projected budget and available funds.

D. Distribution Automation and Reliability

Distribution automation includes fault detection, isolation, and restoration (FDIR) and communicating faulted circuit indicators (CFCIs). FDIR utilizes strategically-placed, communication-enabled fault detection devices, distribution reclosers and motor-operated switches to automate restoration. These systems enable the energy company 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. CFCIs are used to assist in field locating the faulted component of the system and help shorten the time needed for restoration.

1. Distribution Automation Feasibility Study

Prior smart grid reports in Oregon have analyzed a holistic approach to distribution automation deployment and associated cost benefit analysis. A new study of Pacific Power's distribution automation potential has been initiated, in accordance with Staff recommendation[14] to focus on areas where distribution automation may have an improved cost benefit result over the previous holistic approach. The study will be based upon cost and distribution system assumptions that will enhance reliability and yield benefits to customers.

Multiple steps were identified to achieve a preferred outcome of such a study:

- Key criteria and requirements for selection of potential locations
- Necessary communication equipment and protocols at a site need to be identified.
- Switch types and operators to be installed will need to be defined.
- Potential candidates would be screened based on determined criteria.
- Requirements for system integration into SCADA or DMS will be documented.
- Cost-benefit evaluation of screened candidates will be performed.

The key criteria and requirements for selection of potential DA locations have been determined, and are outlined as follows:

- Circuits shall be looped to another circuit and the smallest conductor surrounding the open point between circuits shall be 4/0 AAC with increasing conductor size towards the substations.
- Circuits shall have SCADA control and indication.
- Circuits that were previously used for distribution automation pilots and could be re-commissioned.
- Circuits shall possess the ability to locate a minimum of three gang-operated switching devices, including at the open point.
- Circuits containing critical loads, defined as critical public infrastructure, e.g. hospitals, water processing facilities, and public relief centers, shall be identified.

[14] Order No. 15-367, Docket No. UM 1667, November 13, 2015. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=18500

Criteria for initial circuit screening were applied to potential candidates in the state of Oregon. A preliminary list of potential candidate sites is provided in Appendix H.

Future Actions and Timeline

The remaining steps identified to perform the study are ongoing. A cost benefit analysis will be completed as the study develops. Verification of equipment existing on-site and equipment to be installed at potential locations will require additional time and resources and be based upon availability of field personnel. An update on the study will be included in the 2017 Smart Grid Report.

2. Communicating Faulted Circuit Indicators

The new SCADA Monarch system was commissioned at PacifiCorp Transmission in April of 2016. This new energy management system will enable the integration of CFCI data to a centralized location, where a quantifiable reliability analysis can be performed. To date, there is insufficient reliability data from a manual collection process to perform the reliability savings analyses.

Future Actions and Timeline

Implementation of CFCI data is expected to occur in 2016 and outage event data is possible for analysis and inclusion in the 2017 Smart Grid Report. In addition, an evaluation of the backhaul of fault detector data over the AMI communication network is ongoing. Additional information will be included in the 2017 Smart Grid Report.

3. Distribution Management

As an example of DA functionality included in current scoping processes, Fuse Saving devices are currently being deployed in as a standard device option. Fuse Saving devices have a lower pickup value than breakers and have the ability for peer-to-peer operation to determine system functionality. Although not considered “smart devices” because of their autonomous functionality, their specifications do include two-way communication capability. There are currently more than forty Fuse Saving devices installed. Their locations are given in Table 3.

Table 3 – Fuse Saving Device Locations by District (in Oregon)

Districts	Number Installed
Astoria	11
Klamath Falls	3
Bend, Coos Bay, Medford, and Roseburg	34

Given the limited exposure newly installed Fuse Saving devices have had to reliability events, a comprehensive qualitative analysis of their benefit is not available. However, based on an extremely limited dataset it appears that certain Fuse Saving devices have resulted in an 80% reduction in momentary outages for all customers upstream of the device and an 80% reduction in sustained interruptions for customers downstream. This is consistent with historic fault data that says one of five fault events is permanent. More analysis is required to quantify the reliability impact for sustained interruptions upstream of the device.

The cost of each installed Fuse Saving device is $4000. The Company will be able to establish a more concrete quantitative benefit from the use of these devices with the collection of more data over the next year.

Pacific Power launched an investigation to determine the feasibility and cost of establishing communications with Fuse Saving devices. The scope and cost of integration with the SCADA Monarch energy management system are also being investigated.

Regulator Bid Event

Stock item numbers were added to reflect reverse flow controls. Stock item numbers are now available for units with two potential transformers for use at locations where reverse power flow may exist due to a distributed energy resource. These items are not standard items for construction due to additional costs but are available for use where deemed necessary. For example, these special units would be used in areas with increasing levels of distributed energy resources and light load situations where reverse power flow is probable.

Communication Protocols

The communication protocols for the control devices of reclosers and regulators were evaluated. The devices are DNP 3.0 ready. These controls will be evaluated with the AMI network to be deployed in Oregon.

4. Outage Management

Recloser Bid Event

A bid event for recloser devices launched in April 2016, with a completion date scheduled for September 2016. The event included triple-single reclosers that have voltage sensors on the load side of the bushing to be used for deadline checking in areas with distributed energy resources and potential bidirectional power flow. The units also include sensors on the source-side bushing to allow the unit to function for loop feed, or reverse power flow conditions. In addition to these sensors, reclosers are being purchased communications ready and shall be compatible with an available communication network. These functionalities will be a key element in future conversions to distribution automation schemes. The Company is installing 17 reclosers per year on average, based on the previous five years, in the state of Oregon.

5. Circuit Analysis Software (CYME)

Pacific Power is transitioning to a newer, more powerful distribution system analysis application called CYME. The application will allow better customer load modeling and time series analysis, and will help ensure future planning efforts and project definitions are as accurate as possible.

Project Description

Pacific Power began its transition from ABB FeederAll to CYME at the end of 2015. Pacific Power began utilizing FeederAll to model its distribution system in the 1990's. Users within Pacific Power continue to gain a greater understanding in both the basic and advanced functions available in this new software. Pacific Power is excited to utilize such a powerful tool, and anticipates system planning results will become more accurate with the software's advanced capabilities.

Since a distribution system's response to a change in volt/VAr control schemes is complex, the conclusions drawn from a power flow model are only as valid as the inputs provided to the model. CYME and its GIS Gateway permit the inclusion of several details not part of the former ABB FeederAll model, and these advancements will allow Pacific Power to obtain a more accurate view of the system's behavior in differing scenarios. Specifically, more than 20 different customer types are derived from source data, and each type definition contains voltage response characteristics, utilization and coincidence factors, and demand profiles over time. For example, an irrigation customer with time-of-use metering can be differentiated in the model from a commercial customer with on-site generation. Refinement of these definitions to improve modelling results is ongoing.

Additional functionality within CYME permits devices, such as regulators and capacitors, to be modeled with operational time delay. This functionality, which was not available in ABB FeederAll, allows a power flow analysis with a time profile to illustrate the state of the system between device operations. In CYME, customer generation modeling is also much more robust, so that the influence on one network from generators on a different network can be identified, along with their interaction with line devices over time. For example, the model is capable of identifying the locations of lowest voltage when the output of a chosen subset of solar generation falls by 50% over the time required for the regulating device to respond to the increase in load.

The additional functionality provided by CYME allows users to evaluate many complex scenarios, and furthers engineers' ability to respond efficiently and effectively to proposed system changes while maintaining reliability and safe operation of the system.

Future Actions and Timeline

Several minor improvements remain to be implemented in the Gateway product, which generate the CYME model from Pacific Power's GIS source system. These improvements are anticipated to be completed in late 2016. ABB FeederAll will be phased out and all subsequent planning studies will be completed in CYME.

E. Demand Response

The Company offers two types of demand response programs to customers: direct load control and time-of-use rates. Direct load control programs include Cool Keeper air conditioner (AC) load control and irrigation load control, which are categorized as Class 1 demand-side management under Pacific Power's integrated resource plan. Time-of-use programs offered to specific customer classes are classified as Class 3 demand side-management.

1. 2015 Integrated Resource Plan Update

Pacific Power's least-cost, least-risk preferred portfolio remains composed of Class 2 demand-side management resources (energy efficiency) and front office transactions. These are representative of short-term firm forward market purchases through the front nine years of the IRP 20-year planning horizon. Pacific Power's 2015 integrated resource plan update (IRP Update) modeling results did not select new Oregon direct load control demand response until 2027 in the preferred portfolio.[15] This indicates that Oregon direct load control demand response is not a least-cost resource until 2027 or later. These results differ from the 2015 integrated resource plan (IRP) that indicated 2022 as a start date for new Oregon direct load control demand response.

Pacific Power's 2015 IRP Update preferred portfolio does not include simple cycle combustion turbine plants until 2028 of the planning horizon. This planning date differs from the 2015 IRP that indicated 2022 as a potential date for simple cycle combustion turbine plants.

[15] PacifiCorp, *2015 Integrated Resource Plan Update I* [Online]. Page 50. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015%20IRP%20Update/2015%20IRP%20Update_20160426.pdf

With further load reductions forecast in the 2015 IRP Update, as compared to the 2015 IRP, Class 1 demand-side management resources are not required in the 2015 IRP Update preferred portfolio until 2025 for Rocky Mountain Power and 2027 for Pacific Power.

2. Cool Keeper AC Direct Load Control

Project Summary

Rocky Mountain Power has an existing direct load control demand response program in Utah known as Cool Keeper. Residential and small commercial customers can participate in the program allowing Pacific Power Energy Supply Management to manage air conditioning (AC) loads.

Project Description and Analysis

Pacific Power Energy Supply Management continues to utilize the Cool Keeper program in an effort to manage summer peaks in the Wasatch Front area. Customers are provided an annual credit on their bills for their participation. The Cool Keeper program directly controls customers' AC units with a radio-enabled device that cycles the compressors on and off. Based on the current number of Cool Keeper participants and load calculations, the capacity of the controllable load is approximately 115 MW during peak times.

The communication network for the Cool Keeper devices was upgraded in 2014 to allow two-way functionality. The upgrade performed on the network increased bandwidth and allowed for direct monitoring of the Cool Keeper devices.

The upgrade improved the overall efficiency of the system through enhanced situational awareness of real-time operations and data analysis. Prior to the upgrade, the system was not capable of providing real-time information from the devices and the number of units providing data for analysis was limited to a small number of fixed devices.

After the upgrade, the system can provide operators with an accurate view of real time DR resource availability through the following mechanisms:

- **Daily Resource Analysis –** The system sends a daily message to test connectivity of all enrolled devices and collects data from these devices to measure system availability. This allows the operator to be informed of how many devices are available to respond to a DR event.
- **Hourly Forecasting –** The system uses local weather information, such as temperature and humidity, to estimate the anticipated KW savings from the Cool Keeper resources. This forecast is sent to the PacifiCorp Unit Commitment application for use in the reserves allocation calculation.

The system is now capable of advanced data analysis by collecting information from every enrolled Cool Keeper device, which allows the operators to perform a

Measurement and Verification (M&V) analysis. An M&V analysis consists of the following:

- **Event Validation –** Interval runtime data is collected from all of the devices in the network. Data is analyzed to determine the amount of reduction each device delivered following a DR event. The information allows the Company to target site inspections on any non-performing participants to increase participants during the next event.
- **Customer Segmentation –** Collected interval data allows the Company to segment the Cool Keeper participants into groups: Single Family, Multi-Family, and Small Commercial. Analysis has shown each group has a different load shape and usage pattern. By applying different load shapes and usage patterns based on these groups, the Company is able to provide a more accurate overall forecast.
- **Ad-Hoc Analysis –** Reports can also be run for specific use-cases on interval data. For example, the number of Cool Keeper participants who activate their AC units only when they are in need of cooling were identified. The majority of customers leave AC units operational all day, which allows for their unit to participate during events. The contribution of this subgroup of intermittent participants was determined to analyze their overall performance in the program.

Future Actions and Timeline

Pacific Power Energy Supply Management will continue to leverage Cool Keeper for load management during summer peaking events along the Wasatch Front.

Oregon Assessment

The Company analyzed an air conditioner direct control program, similar to the Cool Keeper program, for deployment in Oregon as part of the 2015 integrated resource planning process. The latest analysis of costs and capacity impacts for an Oregon program can be found in Volume 3 of the Company's DSM Potential Assessment for 2015-2034.[16] Information from this analysis was used to create supply curves for the 2015 IRP.[17] Costs, capacity impacts and supply curves will be updated as part of the 2017 Integrated Resource Plan. k

[16] PacifiCorp, *2015 Potential Study; Volume 3 - Class 1 and 3 DSM Analysis* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSM_Potential_Vol_3_Class_13_Report_FINAL_Jan30-2015.pdf

[17] PacifiCorp, *2015 Integrated Resource Plan Volume I* [Online]. Chapter 6. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

3. Irrigation Load Control

Project Summary

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

Project Description

In 2013, the Company selected EnerNOC to manage a ten-year irrigation load control program through a pay-for-performance agreement. EnerNOC's responsibilities include enrollment, equipment installation, dispatch management, performance calculations, and customer service. Under this program the Company 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 that opt out of participation during specific dispatch events.

In Utah and Idaho, the irrigation load control program is currently available to customer sites on Tariff Schedule 10. Participating sites are compensated for shutting off irrigation load for specific time periods determined by Rocky Mountain Power, and are provided day-ahead notice of dispatch events. Customers have the opportunity to opt out of 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 2015 Rocky Mountain Power Irrigation Load Control Program dispatched seven events for a total of 52 hours from June 1, 2015 through August 21, 2015. In Idaho, the load control events for 2015 ranged from 123 MW to 151 MW as recorded by SCADA/EMS. The median curtailed load dispatch was 141 MW.

Pacific Power's Oregon Pilot Load Control Program (targeting 3MW) for the 2016-2020 irrigation seasons was filed on March 4, 2016 in Advice 16-04[18] and was approved on May 3, 2016, with an effective date of May 4, 2016. The filing requested authorization to implement a pilot irrigation load control program for irrigation customers near the Oregon and California border, specifically in the area comprising the Klamath Basin. The objective of the pilot program is to test the design characteristics of the Company's existing irrigation load control program offered in Utah and Idaho for applicability to agricultural pumping operations in Pacific Power's Oregon service areas. Pacific Power

[18] PacifiCorp Schedule 105, Docket No. ADV 242. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=20031

intends to test for grower acceptance, barriers to participation, and cost to deliver within the Klamath Basin area.

Future Actions and Timeline

The OPUC approval incorporated several staff recommendations to help inform a common and consistent demand response proposal framework. A summary of the recommendations is as follows:

- After the third irrigation season in 2018, Pacific Power will provide a recommendation to expand the program to all of its agricultural customers for the next irrigation season or explain in detail why the pilot program appears to be unsuccessful and what additional information would be obtained in the remaining years of the pilot that would justify its continuance.
- Use the California Public Utilities Commission Distributed Energy Resource Avoided Cost Framework as a guide when conducting the post-season assessment of benefits and costs of the Irrigation Load Control Pilot.

Pacific Power will work with OPUC staff on the development of the filing framework for a demand response program proposal.

Pacific Power Oregon demand response activities for the remainder of 2016 will consist of participant selection and enrollment, equipment installation, triggering management, and post season reporting.

Utilizing the same design as the approved Oregon program, Pacific Power expects to file a 2 MW irrigation load control pilot program for California customers in 2016 and, if approved, commence initial program roll-out for the 2017 irrigation season.

4. Time-Based Pricing

Project Summary

The Company has existing time-of-use rates for various customer classes within each of its six states.

Project Description

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 rebate programs.[19] A combination of time-of-use and critical peak pricing, or time-of-use and critical peak rebate pricing programs, are the most prevalent. If designed and implemented appropriately, these rate structures can present opportunities for

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

creating reductions in energy usage during critical periods when system peaks are present.

Currently, the Company utilizes time-of-use programs where the price for broad blocks of hours is predetermined and constant. However, the Oregon AMI system will be installed with consideration that near real-time programs, such as critical peak pricing, may be pursued in the future. The Oregon AMI system will seamlessly handle existing time-of-use programs.

In Oregon, a two year time-of-use pilot program for irrigation customers was placed in-service beginning with the 2014 irrigation season. The program implemented on-peak energy surcharges and off-peak energy credits. A report on the pilot was filed with the OPUC in December 2014. An additional report was filed with the OPUC in December 2015[20].

The 2014 Pacific Power time-of-use irrigation pilot was implemented to assess the interest, willingness, and ability of Oregon irrigation customers to shift their energy usage away from designated on-peak periods. Although the potential savings for the customer through shifting usage was significant, customer participation was below the necessary threshold for conducting a successful pilot. In 2015, Pacific Power solicited input from irrigators to improve participation in the pilot. Surveys and in person meetings were conducted in order to better understand the needs of irrigators in the area. Interest in the pilot and its potential for savings were highest in the Klamath Falls area. Based on feedback provided from those meetings, Pacific Power modified its pilot for 2015 to include a greater on-peak to off-peak rate ratio for increased potential savings and concentrated the location of potential participants to the Klamath Falls area.

In 2015, Pacific Power sent material concerning the pilot and enrollment information to all irrigation customers in the Klamath Basin area to encourage customer participation. Invitations to participate in an irrigation workshop were also sent to Klamath Basin irrigators in Oregon and California. The workshop was attended by more than 200 participants.

The irrigation workshop was sponsored by Pacific Power, Energy Trust of Oregon, irrigation districts, and water user associations in the area with the intent to inform customers about energy and saving programs available to irrigators. Pacific Power gave a presentation at the workshop to describe the time-of-use pilot along with potential benefits to participants; customers had the opportunity to ask questions. Customer service and billing personnel were available at the workshop to discuss the pilot further and to

[20] PacifiCorp Irrigation Time of Use Schedule 215, Docket No. RE 153. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19304

enroll customers for the pilot. The majority of customers enrolled in the pilot attended the workshop. Interest in the pilot increased significantly in 2015 and the participation cap was expanded to include all of the approximately 95 meters that signed up in 2015.

In February 2016, Pacific Power filed Advice No. 16-03[21] describing the results of a post-season survey of pilot participants along with a request to extend and expand the pilot for two additional years. The single year of data obtained in 2015 was unlikely to be representative of typical usage data for the area because it had been a low water year. Pacific Power proposed no changes to the time-of-use periods or on-peak and off-peak rate adders but proposed to open the pilot up to 75 new participants in the Klamath Basin area. At OPUC staff request, the number of new participants was lowered to 25. On April 21, 2016, the proposed filing was approved by the OPUC with additional reporting requirements due after the end of the 2016 irrigation season, including an estimate of the capacity reduction related to the pilot and an estimate of potential cost savings, both near-term and long-term.

Lessons Learned from the Irrigation TOU Pilot

Pacific Power learned from its TOU Pilot that it was able to increase participation in the irrigation TOU program through three methods:

- Increasing the potential for customer bill savings.
  - In 2015 the company increased the ratio between on- and off-peak rates under the pilot to five-to-one. With this ratio a customer shifting 100% of their energy usage to off-peak could achieve a 33% savings on of their summer bills. This significant percentage likely encouraged more irrigators to participate because the potential for savings was great enough to offset the cost of operational efforts and/or equipment changes that would allow them to shift energy usage.
- Concentrating the pilot in a location where customers were more acutely aware of the cost of electricity.
  - Many customers in the Klamath Basin were served under extremely low rate energy contracts through 2006. These irrigators experienced significant rate increases as they transitioned over seven years from the contract rates of less than one-cent per kilowatt-hour to the standard irrigation rates. The electric bill became a much more significant cost to the business for these irrigators and therefore they were receptive to the opportunity to achieve bill savings.

[21] PacifiCorp Schedule 215 – Time-of-Use Pilot Supply Service. Docket No. ADV 224. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19999

- Conducting in-person outreach with the opportunity for potential participants to ask questions.
    - Pacific Power held a workshop in the Klamath Basin area to present energy and cost saving programs available to irrigation customers. Customers were able to ask questions about the TOU pilot in person to customer service and billing personnel at the meeting. Communications regarding the pilot were sent to all customers eligible to participate and were also available at the workshop. Approximately 95 customers signed up for the pilot in 2015, the majority of which signed up at the workshop.

Regarding residential time-based pricing, as of December 31, 2015, there were 1,130 Oregon residential customers participating in the residential time-of-use pricing. The Company communicates residential time-of-use on its website (www.pacificpower.net/tou), which contains links to frequently asked questions, and on-peak and off-peak hours and pricing charts. Customers have the ability to enroll in the program online and by phone. Additionally, Pacific Power includes time-of-use program information in customer bills at least twice a year.

Table 4 is an updated summary of Pacific Power's price schedules by state and shows current levels of participation in mandatory and voluntary programs**.**

The Company's Idaho Schedule 36 Optional Time of Day has a higher participation rate than optional residential time of use tariffs in Oregon and Utah, because its structure generally provides a greater benefit for customers, especially higher usage customers. Along with a higher basic charge, Schedule 36 customers are not subject to tier block pricing used for standard residential customers on Schedule 1.[22]

In contrast, Oregon optional residential time-of-use rates are based upon applying credits and surcharges to the standard rates for those customers. As a result, time-of-use customers on portfolio Schedule 210 have a higher effective rate during on-peak times compared to standard Oregon residential customers on Schedule 4.[23]

[22] Idaho Regulatory Information. *Rocky Mountain Power* [Online]. Available: https://www.rockymountainpower.net/about/rar/iri.html.
[23] Oregon Regulatory Information. *Pacific Power* [Online]. Available: https://www.pacificpower.net/about/rr/ori.html

Table 4 – Time-Based Rate Schedule Participation by State

Description	State	Schedule	Participating Customers (Dec. 31, 2014)	Eligible Customers	Participating Eligible Customers	Voluntary or Mandatory
Residential TOU Pricing	Idaho	36	12,770	60,556	21.09%	Voluntary
	Oregon	4/210	1,130	487,060	0.23%	Voluntary
	Utah	2	424	755,425	0.06%	Voluntary
General Service (*Business Sector and Irrigation*) TOU Pricing, Either Energy or Demand	California	AT48	19	19	100%	Mandatory
	Idaho	35/35A	3	10,544	0.03%	Voluntary
	Oregon	23/210	263	77,345	0.34%	Voluntary
	Oregon	41/210	60	5,509	1.09%	Voluntary
	Oregon	41/215	90	100	90%	Voluntary (Pilot)
	Oregon	47	7	7	100%	Mandatory
	Oregon	48	196	196	100%	Mandatory
	Utah	6A/6B	2,455	100,517	2.44%	Voluntary
	Utah	8	244	244	100%	Mandatory
	Utah	9/9A	164	164	100%	Mandatory
	Utah	10	240	3,127	7.68%	Voluntary
	Utah	31	7	7	100%	Mandatory
	Washington	47T	1	1	100%	Mandatory
	Washington	48T	66	66	100%	Mandatory
	Wyoming	33	10	10	100%	Mandatory
	Wyoming	46	83	83	100%	Mandatory
	Wyoming	48T	29	29	100%	Mandatory

F. Distributed and Renewable Resource Enhancements

1. Distributed and Renewable Resources

Pacific Power monitors customer generation and net metering customers throughout its service territory in an effort to ensure participation figures and generation capacities correspond with projected trends. Pacific Power has seen an increase in net metering customers across all of its service territory for the 2016 calendar year compared to previous years. A monthly report for June 2016 that indicates net metering and customer generation is provided in Appendix I.

2. Interconnection Standards and Smart Inverters

The OPUC held a workshop on January 19, 2016 to determine the resource value of solar.[24] Pacific Power presented information on smart inverters and advanced inverter functionalities during the workshop.[25]

Summary

Inverters with advanced functionalities, referred to as smart inverters, allow for conversion of DC to AC for grid connectivity, as well as providing advanced capabilities to support the stability, reliability, and efficiency of the electric grid. Such capabilities are imperative with penetration levels of inverter-based DER projected to increase through 2040[26] and necessitate standards be identified and followed to ensure a unified system.

Pacific Power's interconnection standards and policies are based on the following standards, as well as other national, state, and local jurisdictional guidelines:

- IEEE 1547 – *Standard for Interconnecting Distributed Resources with Electric Power Systems*[27]
- UL 1741 – *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*[28]

---

[24] Staff's Updated Agenda for 1/19/16 Workshop, Docket No. UM 1716. *Oregon Public Utility Commission* [Online]. Available: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19362
[25] Parties' Presentations for the 1/19/16 Workshop, Docket No. UM 1716. *Oregon Public Utility Commission* [Online]. Available: http://edocs.puc.state.or.us/efdocs/HAH/um1716hah101819.pdf
[26] U.S. Energy Information Administration (2015). *Annual Energy Outlook* [Online]. Table A16 p A-31. Available: https://www.eia.gov/forecasts/aeo/pdf/tbla16.pdf
[27] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. *IEEE* [Online]. Available: http://grouper.ieee.org/groups/scc21/1547/1547_index.html
[28] UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. *Underwriters Laboratories* [Online]. Available: http://ulstandards.ul.com/standard/?id=1741_2

Background of IEEE 1547

The IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems is a family of standards that serve as the interconnection standards for DER and address the technical and test requirements for systems less than 10 MW. The IEEE 1547 standard was published in 2003 and focuses on the technical specifications for, and testing of, the interconnection. The requirements are universally needed for interconnection of distributed energy resources, including synchronous machines, induction machines, and power inverters/converters, and will be sufficient for most installations.

The IEEE 1547 interconnection suite contains requirements pertinent to interconnection, control, operation, intentional islanding, and conducting impact studies of DER with electric power systems. IEEE 1547 is comprised of the following standards:

- IEEE 1547 (2003 and 2014 Amendment 1) – *Standard for Interconnecting Distributed Resources with Electric Power Systems*
    - IEEE 1547.1 (2005 and 2015 Amendment 1) – *Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces*
    - IEEE 1547.2 (2008) – *Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems*
    - IEEE 1547.3 (2007) – *Guide for Monitoring Information Exchange, and Control of Distributed Resources with Electric Power Systems*
    - IEEE 1547.4 (2011) – *Guide for Design, Operation, and Integration of Distributed Resources Island Systems with Electric Power Systems*
    - IEEE 1547.6 (2011) – *Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks*
    - IEEE 1547.7 (2013) – *Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection*
    - IEEE P1547.8 – *Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded use of IEEE 1547-2003*

Amendment to IEEE 1547

In mid-2013, members of the IEEE 1547 standards community initiated a "fast-track" amendment to IEEE 1547, labeled IEEE 1547a. Published by the standards organization in May 2014, IEEE 1547a is a "permissive" update to the existing IEEE 1547 whose main purpose is to permit some functionalities not currently allowed in IEEE 1547. The amendment has initiated a full revision of IEEE 1547 in consideration of evolving use-cases of modern inverter-based distributed energy resource systems.

Company Participation

Pacific Power is an active member of the IEEE 1547 working group and continues to support the standards' revision process. Currently, the working group is in the process of drafting a complete revision of the standard that will allow distributed energy resources to have a more significant contribution to the local energy company's electric power system. The fully revised standard will be technology agnostic with the requirements focusing on functionality. Prescriptive updates to the standard, as to how to implement a solution to satisfy the requirement, will be omitted. The working group is also investigating processes to adopt prudent smart inverter functionalities as standard features to enable higher penetrations of distributed generation.

Traditionally, energy grids were not designed to accommodate active generation and storage at the distribution level. IEEE 1547 is being updated due to an increase of DER penetration to reflect corresponding increase in technology and use-cases of DER integration.

In addition to modifications throughout the standard, three sections of IEEE 1547 are undergoing significant changes:

- Clause 4.1.1 – Voltage Regulation
- Clause 4.2.3 – Voltage Response to Area Abnormal Voltage Conditions
- Clause 4.2.4 – Frequency Response to Area Abnormal Voltage Conditions

The main intent of these changes is to clearly define and understand the challenges of integrating smart inverters into the suite of interconnection standards. The changes are anticipated to address general technical specifications, performance categories, and default equipment settings. The final draft of IEEE 1547 is expected to be balloted in Q4 2016, published in Q2 2017, and approved in 2018.

Since UL 1741 will not be testing the amended interconnection standard, any revisions made to IEEE 1547.1 must be modified to identify the test procedures to ensure conformance with the requirements listed in the full revision. The standards committee of IEEE is working expeditiously towards revising IEEE 1547.1, which will provide testing requirements for the new IEEE 1547 standard. Coordination between the UL 1741 testing and certification requirements and the new IEEE 1547.1 testing requirements is currently in process.

IEEE 1547 was established as the national standard for the interconnection of distributed energy resources by the Energy Policy Act of 2005. Adherence to, or use of, an IEEE standard is considered an industry best practice. Nonetheless, individual states have the ability to enforce such industry standards. In the state of Oregon, OAR 860-082-0025

(Applications to Interconnect a Small Generator Facility)[29] states "a public utility must use IEEE 1547 and IEEE 1547.1 to evaluate small generator interconnection applications unless otherwise specified in these rules or unless the Commission grants a waiver to use different or additional standards." For this reason, the Company will continue to adhere to IEEE 1547 as currently written along with any future revision of the standard.

Future Actions

Pacific Power will await a revised IEEE 1547 standard to update internal interconnection standards and policies due to the existing effort to revise IEEE 1547, which is anticipated to encapsulate requirements found in IEEE 1547a. Pacific Power intends to implement the advanced inverter functionality recommendations to be defined in the IEEE 1547 standard. Prior to publishing of the new standard, it is Pacific Power's practice to require advanced inverter functionalities under circumstances where distribution system constraints warrant their use. For instance, a distribution circuit with voltage regulation issues may require additional VAR support from a distributed energy resource interconnection to accommodate the interconnection. Advanced inverter functionalities can provide the additional VAR support.

3. Electric Vehicle Charging Infrastructure

Pacific Power continues to experience slower than anticipated growth of electric vehicles (EV) in its service territory. Based on projected growth, large-scale deployment of electric vehicles is expected to have limited impact to the Company's distribution network.

Pacific Power continues to engage with its stakeholders in order to facilitate public charging infrastructure development and opportunities.

In Oregon, Senate Bill 1547[30], known as the Clean Electricity and Coal Transition Act, reaffirms the state's commitment to transportation electrification. The bill encourages developing programs and infrastructure necessary for increased usage of electricity to provide power to all or part of a vehicle for energy efficiency and carbon reduction purposes.

In California, the Company provided letters of support to applicants seeking funding from the California Public Utilities Commission (CPUC) for the purpose of establishing EV charging infrastructure. If successful, the additional EV infrastructure investments

[29] Division 82, Small Generator Interconnection Rules. *Oregon Secretary of State* [Online]. Section 7(d). Available: http://arcweb.sos.state.or.us/pages/rules/oars_800/oar_860/860_082.html
[30] Oregon Senate Bill 1547. *Oregon State Legislature* [Online]. Available: https://olis.leg.state.or.us/liz/2016R1/Measures/Overview/SB1547

would further efforts to complete the West Coast Green Highway. Funding from CPUC would also support programs and planning efforts related to the implementation of EV infrastructure.

In Utah, Senate Bill 115[31], known as the Sustainable Transportation and Energy Plan Act (STEP), is an effort to reduce emissions from fossil-fuel power plants, explore new methods to utilize battery storage and solar systems, and expand EV charging stations. Some primary goals of STEP include:

- Reduced emissions through increased EV usage in the Utah market.
- Continued investments in energy efficiency measures that deliver energy savings.
- Maintain stable and low electricity prices for Utah customers through a proactive approach.
- Increased cognizance of customer charging patterns in relation to coincident system peaks for operational considerations within the distribution network

Future Actions

The Company is researching the feasibility of transportation electrification programs throughout its service territories to align itself with goals set forth in the Clean Electricity and Coal Transition Act for Oregon and the Sustainable Transportation and Energy Plan Act for Utah.

[31] Utah Senate Bill 1547. *Utah State Legislature* [Online]. Available: http://le.utah.gov/~2016/bills/static/SB0115.html

VI. Roadmap to Grid Modernization

Development of an objective roadmap must consider the economic value of individual components, technology maturity and interdependencies. Although funding levels will vary, the Company's 10-year capital plan provides for investment for the current roadmap. In addition, funding is planned for smart grid technologies expected to be leveraged by the implementation of AMI, such as data analytics, outage management, and distribution automation.

A roadmap of Pacific Power's current and anticipated grid modernization investments is shown in Figure 5. Oregon AMI network build-out and meter deployment begins in Q2 2016 with expected completion in 2019. CYME circuit analysis software implementation will be complete by Q4 2016. NERC MOD-33 requirements will be met by enforcement date of May 2017. A transportation electrification initiative will be proposed to satisfy Oregon SB 1547 by the end of 2016. A qualifying energy storage system will be procured on or before January 1, 2020 to satisfy Oregon HB 2193. Oregon irrigation load control programs will continue through 2020. Participation in the IEEE 1547 working group will continue with an anticipated balloting in Q4 2016, publication in Q2 2017 and approval in 2018.

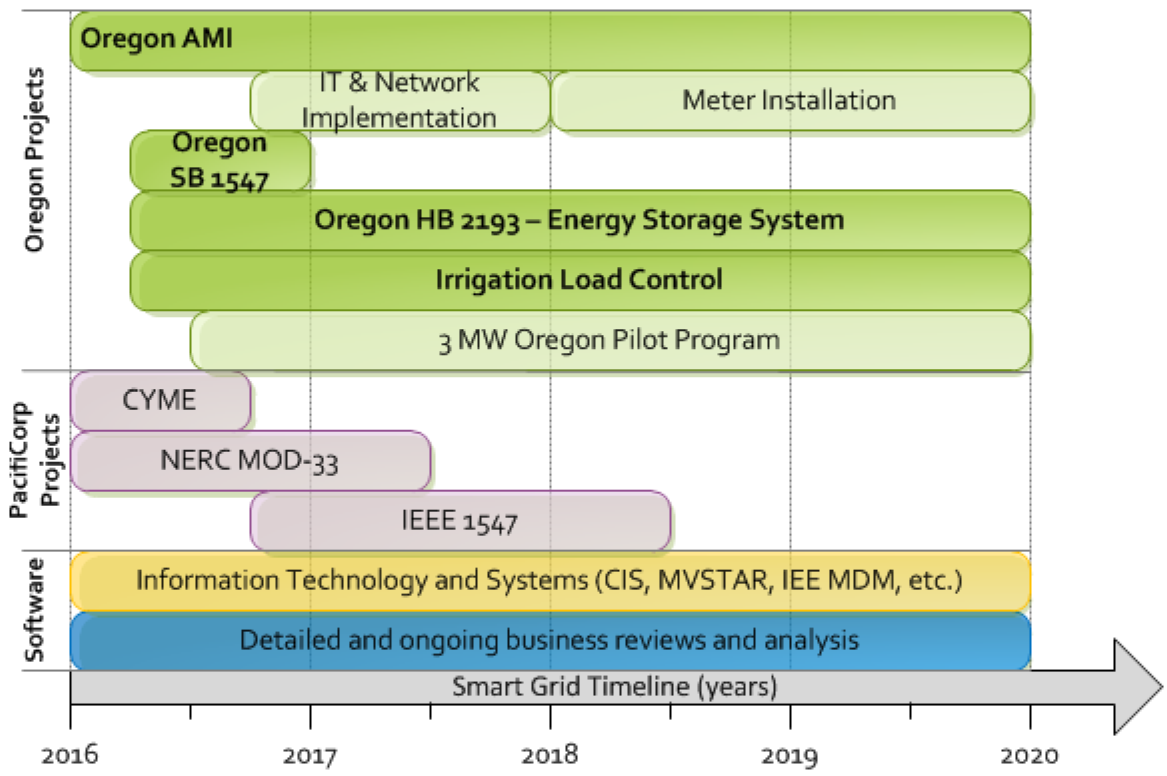


Figure 5 – Smart Grid Roadmap

VII. Conclusion

Pacific Power continues to develop a strategy to attain long-term goals for grid modernization and smart grid related activities to continually improve system efficiency, reliability, and safety, while providing a cost-effective service to our customers. Pacific Power continues to monitor smart grid technologies and determine viability and applicability of implementation to the Company's system.

Appendix A – Summary of Project Updates

Project status and timeline is summarized in Table 5.

Table 5 – Summary of Project Updates

Topic	Project	Status	Cost	Benefit	Future Actions and Timeline
Dynamic Line Rating	West-of-Populus	Deployed. Evaluation ongoing	Installed cost of $2.37m Ongoing engineering costs for evaluation	Increased line capacity based on ambient weather conditions	West-of-Populus project fully functional. Updates to be provided in 2017 Report.
Transmission Synchrophasor Demonstration	PacifiCorp's Western Interconnection Synchrophasor Project	Complete	Ongoing O&M costs to ensure valid data provided to PeakRC	Increased reliability through real-time measurements provided to PeakRC	Awaiting PeakRC website development for data access; expected 2016.
	Evaluation of model validation process.	In progress	Ongoing engineering costs	Improved planning dynamic model based on actual system response data	Model validation evaluation; expected 2016.
	NERC MOD-033	In progress	Estimated equipment cost of $67k per site	Establish consistent validation requirements for reliability analysis	Will meet enforcement date of May 2017.
Centralized Energy Storage Assessment	Oregon HB 2193 – Energy Storage	In progress	Estimated installed cost of $4.5m for 5MWh BESS system. Ongoing engineering costs to develop proposal	Offset of T&D deferral, estimated range of $2m to $10m savings	Ongoing coordination with OPUC.
	CES Assessment	Complete	Internal engineering study costs	Potential use of DER to offset or defer traditional transformer upgrade or replacement	Study provided to Staff.

	DER Alternatives Template	Complete	Internal engineering costs to develop template	Potential use of DER to offset or defer traditional transformer upgrade or replacement	Deployed for use throughout Company.
	Redmond Circuit Analysis	Complete	Internal engineering study costs	Potential use of DER to offset or defer traditional system reinforcement project	Additional details on analysis and cost comparisons provided in Appendix F.
	Distribution Substation Metering	Pilot	$15k per meter. Ongoing $20 per month per meter for cellular connection	Enhanced monitoring capabilities for increased visibility of loading and voltage levels on high DER penetration circuits	Under evaluation; expected deployment by end of 2016.
	OSU Energy Storage Partnership	Complete	Proposed $85k for interconnection and project support.	Improved reliability and resilience of OSU data center	Project cancelled.
Communicating Faulted Circuit Indicators	Cost-benefit analysis	In progress	Installed cost $40k (16 sites) Ongoing $15 per month per site for data	Quantifiable reliability analysis of CFCI deployment	Expected 2017.
	SCADA integration	Delayed deployment	Estimated $55k for integration cost	Improved visibility of fault and outage events for further analysis and potential reliability enhancement	Dependent on Monarch implementation; expected 2017.
Distribution Automation and Reliability Analysis	Fuse Saving device deployment	Complete	$4000 per installed device	80% reduction in MAIFI. Impact to other customers still under investigation.	Offered as standard device option.

	Feasibility of conducting study to determine DA device implementation	In progress	Estimated $30k per switching device. Additional costs, including communications and OMS integration, are being investigated.	Improved reliability (SAIDI, SAIFI) and potential reduction in avoided CMI and CI costs. Based on 2016 reliability project costs, $26 per avoided CMI and $125 per avoided CI would be threshold for DA evaluation.	Feasibility study will analyze reduction in SAIDI/SAIFI and associated costs. Updates to be provided in 2017 Report.
Circuit Analysis Software (CYME)	Ongoing software deployment	In progress	Confidential and proprietary	Improved customer load modeling and time series analysis to provide more accurate planning scenarios. Varied cost savings from potential enhanced utilization of existing assets.	Complete integration expected by end of 2016.
Advanced Metering Infrastructure for Oregon Customers	Implementation of Advanced Metering Infrastructure in Oregon	In progress	See Attachment A (confidential and proprietary)	Improved customer service, reduced O&M expenses, and provides platform for future Smart Grid applications.	Anticipated project completion date 2019. See Table 2.
Customer Communications and Programs	Lessons learned from irrigation pilot program	Complete	N/A	Potential increased participation in future irrigation pilot programs	See Section V.E.4.
	Customer web portal	In progress	Cost included in AMI total capital cost	Allow customers to monitor and manage energy consumption	Released with AMI project completion. See Table 2.
Demand Response - Irrigation Load Control	Initiation of pilot program in California and Oregon	Active deployment in Oregon	Confidential and proprietary. Aggregated costs may be available post-irrigation season.	Reduced load during periods of peak demands	California deployment expected 2017.

Demand Response - Cool Keeper AC Direct Load Control	Network upgrade complete	Complete	Confidential and proprietary	Increased bandwidth and direct monitoring for enhanced situational awareness of real-time operations and resource availability	No planned updates at this time.
Smart Inverters	Ongoing development of standards	In progress	Ongoing engineering costs	Improved system stability and reliability with increasing levels of DER.	Continued participation in workgroup. Publication of IEEE 1547 expected 2018.
Electric Vehicle Infrastructure	Initiation of Oregon SB 1547-B - Clean Electricity and Coal Transition Plan	In progress	Ongoing engineering costs to develop Transportation Electrification proposal	Development of programs and infrastructure necessary to provide power to electric vehicles	Ongoing development and coordination with OPUC.
	Initiation of Utah Senate Bill 115 - Sustainable Transportation and Energy Program	In progress	Ongoing engineering costs to develop proposal	Reduced emissions from fossil-fuel plants and increased EV charging stations	Ongoing development and coordination with Utah PSC.

Appendix B – Stakeholder Recommendations

The Company provided a draft report to stakeholders. A summary of stakeholder recommendations and action taken by the Company is given in Table 6.

Table 6 – Stakeholder Recommendations and Company Actions

Stakeholder	Recommendation	Company Actions	Page(s)
OPUC	There is a tracked change deletion at the top of the page.	This was caused due to a compatibility error with Microsoft Word. The Company will submit future documents in PDF format.	Throughout
OPUC	The Company provides a list of bullet points of key efforts in the State of Oregon. Staff would find it helpful to elaborate on which of these projects are ongoing or new.	The intent of the bulleted list was to describe new projects in Oregon. Appendix A provides a list of projects, their status, and anticipated completion dates.	1
OPUC	The Company includes a list of enhancement initiatives. Staff would find it helpful to include in the report actual costs demonstrating a cost-benefit analysis of each of these initiatives. Staff is comfortable with these being filed as an attachment.	Actual costs, if available, have been addressed individually throughout the report.	Throughout
OPUC	**AMI** - The Company includes a one-sentence description of why the Company has finally decided to pursue smart grid. Staff would find it helpful to include in the report a more comprehensive explanation. If possible, include the actual costs demonstrating a positive business case for PacifiCorp and how it would save ratepayers money. Staff is comfortable with these being filed as an attachment.	The Company is pursuing AMI in Oregon, which is a component of smart grid and/or grid modernization, technology. Attachment A (confidential and proprietary) provides additional information regarding financial analysis of the Oregon AMI.	9, Attachment A

OPUC	**AMI -** The Company includes a one-sentence description of cost savings. Staff would prefer an outline of what these cost savings would be. Are these saved costs to customers or the Company?	Financial analysis provided in Attachment A (confidential and proprietary).	10, Attachment A
OPUC	**AMI -** The Company includes a statement about customer benefits. Staff would prefer including a dollar value of these benefits.	Financial analysis provided in Attachment A (confidential and proprietary).	10, Attachment A
OPUC	**NERC MOD-033 -** The Company discusses a new NERC standard. Staff would prefer including a cost estimation of what this is costing the Company.	The Company anticipates a scope and estimate will be available for the 2017 report. Additional information provided in the report.	18-19
OPUC	**Distribution Substation Metering** - The Company describes an advanced substation metering pilot. Staff would prefer an outline of what the potential costs and cost savings would be for such a program.	Per site costs and a block cost for a SCADA installation have been provided in the report.	22-24
OPUC	**DA Feasibility Study** - Staff is concerned that a qualitative and quantitative outline of potential benefits has yet to be included. Staff has brought this concern to the Company both in the 2014 and 2015 PacifiCorp Smart Grid Report.	The Company has identified steps necessary for such a feasibility study. At the time of reporting, key criteria and requirements for selection of potential locations have been determined. Remaining steps of the study include: identifying equipment at identified sites, defining switch types and operators to be installed, identifying requirements for integration into SCADA, and performing a cost-benefit evaluation. An update on the study will be included in the 2017 Report.	25-26
OPUC	**Fuse Saving Devices -** The Company describes Fuse Saving devices. Staff would prefer an outline of what the potential costs and savings are for these devices.	Costs of installed Fuse Saving devices provided in the report.	26-
OPUC	**AMI -** Staff would find it helpful to include a description of how the Company anticipates the new AMI technology it is proposing to apply to TOU.	Additional clarification is provided in the report.	33

OPUC	**TOU -** ODOE asked in the workshop (7/12/2016) why Idaho's residential TOU participation is so high. If possible, please include an explanation of why this is so in the final report.	Additional information provided in the report.	36
OPUC	**IEEE 1547 -** Staff would find it helpful to have an explanation of context for PacifiCorp's commitment to participate in IEEE 1547. As PacifiCorp mentioned in the workshop (7/12/2016), this is an industry best practices working group and is not a regulatory mandate. What is the reason for updating some of the standards? Staff would like some context as to how wide this standard applies—e.g., do all utilities in the United States participate? Why has the Company chosen to pursue these best practices? Is it related to the Company's new AMI implementation?	Additional information and clarification related to enforcement and adherence to IEEE standards provided in the report.	40
OPUC	**Appendix A -** Again, Staff would prefer an outline of the costs and benefits of these projects and estimated savings to customers/the Company.	If available, costs are provided within individual project sections. Benefits to the customer, whether quantitative or qualitative, are discussed in respective project sections.	Throughout
OPUC	For ease of reading, Staff would find it helpful to include in the header of every page what Appendix a particular exhibit belongs to. Or, including a title page before each Appendix. Appendix E in particular was confusing to follow.	Appendix headers have been changed to clearly identify every page belonging to a particular appendix section.	45-77
ODOE	**AMI -** ODOE recommends the Company enhance the Smart Grid Report with some discussion as to whether the AMI system the Company is deploying will be capable of this entire list of applications, or, if not, what other technologies or programs the Company would also need to develop concurrently or after AMI deployment.	The Company will continue to develop business cases for each application and prioritize based on results. Additional clarification of AMI future application deployment is provided in the report.	13

ODOE	**DER Alternatives Tool -** ODOE strongly believes that a more detailed description of the functionalities of the tool, including critical assumptions and inputs, is necessary to assure stakeholders that the tool does a fair job of evaluating the benefits that DER alternatives can provide.	The purpose of the DER Alternatives Tool is to screen benefits to determine if an evaluation should be completed. Additional information related to inputs for the tool are provided in the report.	21
ODOE	**Cool Keeper -** ODOE encourages the Company to identify demand response program opportunities here in Oregon that build on the success of the Cool Keeper program. If the Company has investigated replicating the Cool Keeper program in Oregon, that analysis would be very insightful and we encourage the Company to include such analyses in future Smart Grid Reports.	Additional information related to an assessment of a Cool Keeper, or similar program, in Oregon is provided in the report.	31
ODOE	**IEEE 1547 -** ODOE recommends more detail be included in the current Smart Grid Report about the circumstances which would allow the use of smart inverters.	Additional information provided in the report.	41
ODOE	**Synchrophasors** - ODOE would like to better understand collaboration, if any, within the Company on the use of synchrophasors and other transmission smart grid initiatives to improve real-time situational awareness for transmission operations.	Additional information provided in the report.	18

Appendix C – Dynamic Line Rating

Line flow, ratings, and conductor temperature for the Populus-Kinport 345 kV line on the West-of-Populus path are shown in Figure 6.

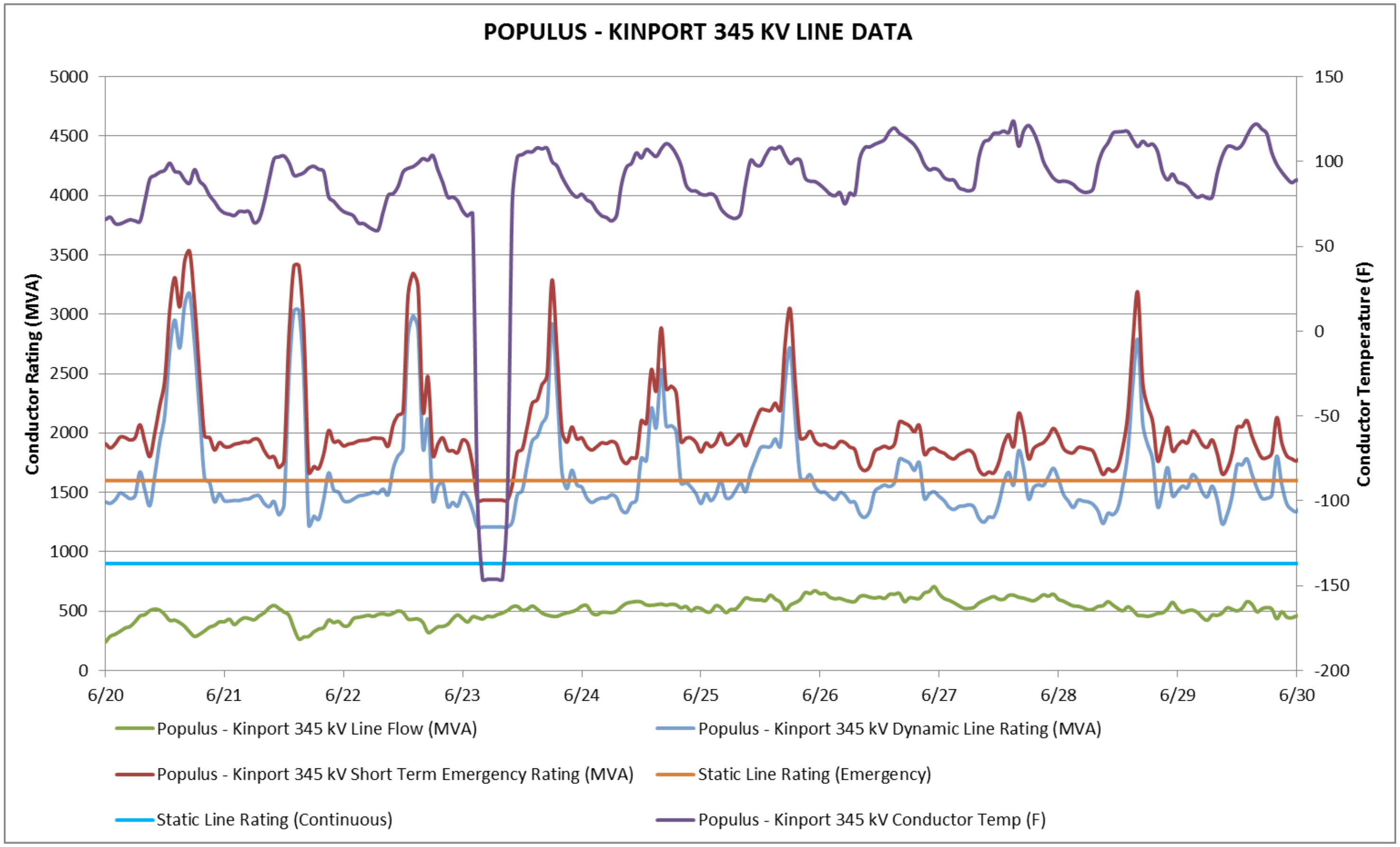


Figure 6 – Dynamic Line Rating for West of Populus

Appendix D – Locations of Equipment for MOD-033 Requirement

Locations considered for equipment to provide the data necessary to satisfy MOD-033 requirement are listed in Table 7.

Table 7 – Locations Identified for MOD-033 Requirement

Pacific Power	Rocky Mountain Power
Burns	90th South
Dixonville 500	Ben Lomond
Fry	Camp Williams
Knott	Clover
Malin	Dave Johnston
Meridian-PP&L	Emery
Pilot Butte	Goshen
Troutdale X2	Huntington
	Jim Bridger
	Midvalley
	Mona/Current Creek
	Naughton
	Oquirrh
	Pinto
	Point of Rocks
	Populus
	Red Butte
	Sigurd
	Spanish Fork
	Steel Mill/Lakeside 2
	Terminal
	Windstar

Appendix E – MOD-033 Model Validation

Figure 7 shows the input PMU voltage data of actual system voltage compared against a power flow model. Figures 8 and 9 show the actual PMU data and model responses with respective validated and non-validated models. The combination of these comparisons, accompanied by guidelines for unacceptable results, is essential to satisfying the requirements.

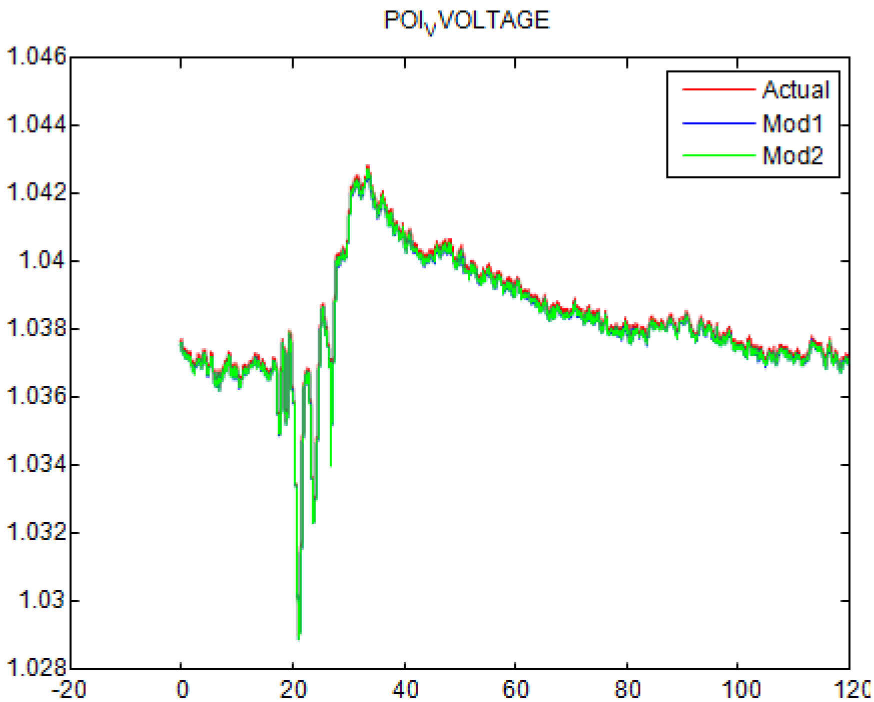


Figure 7 – PMU Input Data

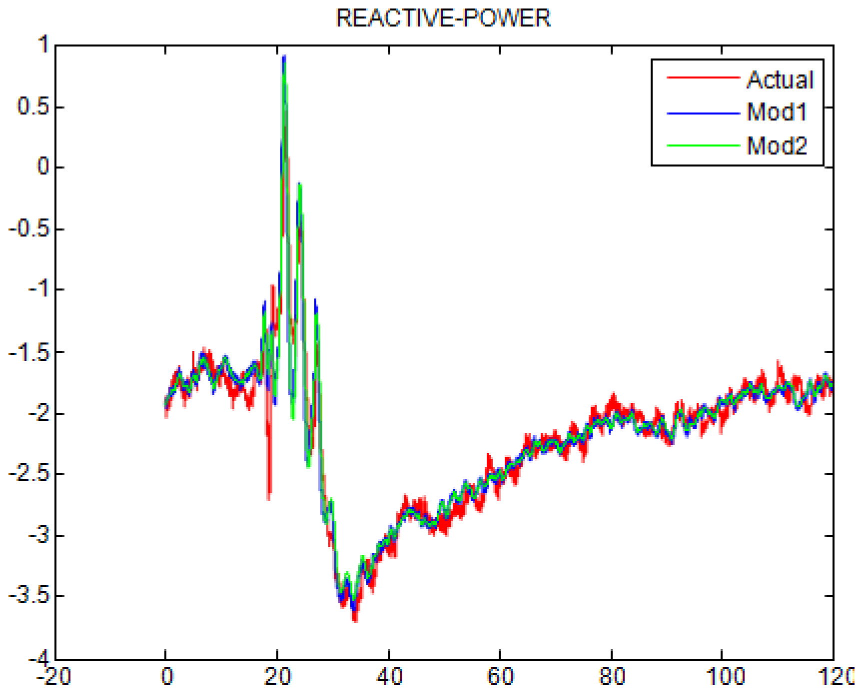


Figure 8 – Actual PMU Data Validates Model

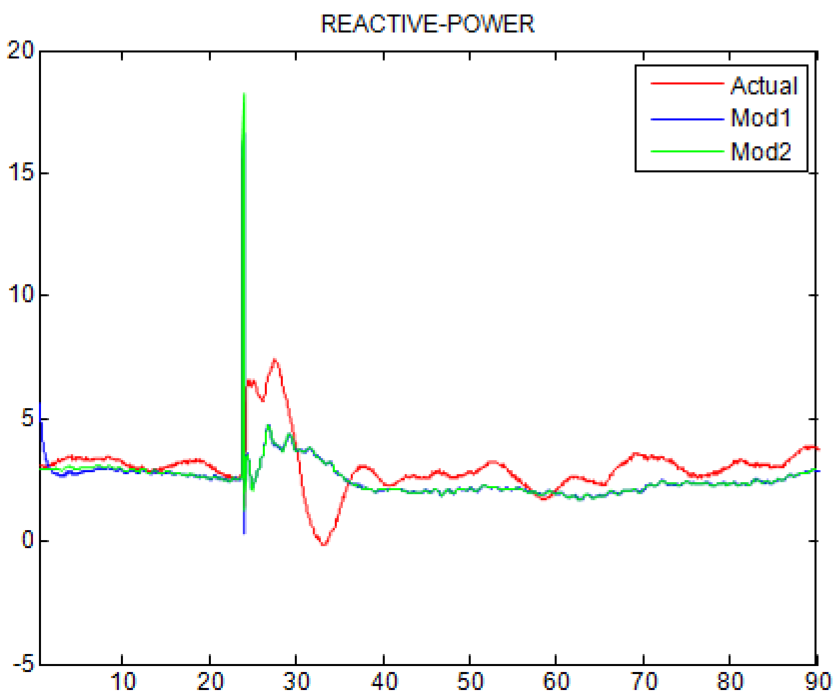


Figure 9 – Actual PMU Data Invalidates Model

Appendix F – DER Example Template

The following DER alternative solutions template was applied to the Redmond 5D22 circuit:

Distributed Energy Resources

Alternative Solutions Template

This template is a planning screening tool used to explore the possibility of utilizing Distributed Energy Resources (DERs) as alternatives to traditional system reinforcements. The typical traditional projects to be reviewed are projects to add or replace a distribution substation transformer including a new substation and/or add or uprate a distribution feeder to alleviate a loading or voltage criteria issue.

Solar generation, energy storage, and demand side management will be addressed as alternatives, respectively, in the succeeding tabs in this workbook. The feasibility of the DER alternative will consider whether the DER may provide the MW capacity and MWh energy needed to reduce a facility's loading to below a specified level based on the facility's load curve.

Solar: The feasibility/cost of solar generation will be explored by plotting the daily load profile of the projected peak and the target facility loading. Utilizing NREL's PVWatt hourly solar data, a solar profile will be compared to the load profile and target facility loading to determine the feasibility and size of a solar DER alternative. Although thresholds may not be reached, further analysis and risk assessment may still show solar is a viable solution. Risk should be discussed on an individual project basis.

Energy Storage: The feasibility/cost of energy storage (battery) will be explored by plotting the daily load profile of the projected peak and the target facility loading. The MW and MWh size of the energy storage device will be estimated based off the amount of MW and the amount of time that the load exceeds the target loading threshold while respecting the need to have adequate off-peak charging time. Although thresholds may not be reached, further analysis and risk assessment may still show energy is a viable solution. Risk should be discussed on an individual project basis.

Demand Side Management: Utilizing multiple planning parameters, i.e. region, # of customers, customer category, the applicable company template will apply generalized criteria to determine potentially available kW from demand side management. A DSM alternative is shown for representative purposes and would typically require the most lead-time to develop as an actual solutions and may only be a temporary measure to implement because of the structure of the programs and the regulatory environment and lead-time.

Once the analyses are complete for each DER alternative, the planner will use the Results Summary tab and summarize the results and costs for inclusion in the applicable project documentation, i.e. APR, Project Summary Sheet, AMPS, IAD, Project Charter, and/or AFE. It should be noted that the more feasible or economical solution may be a combination of DERs. For example, insufficient off-peak charging energy for an energy storage only alternative may require solar generation to make a DER alternative feasible and vice-versa.

DER Alternative Solutions Template - USER GUIDE

The user guide is a short synopsis on how to use the DER Alternative Solutions Template. Information on calculations, data, and cost estimates is available on this tab as a guide as you complete the template. Utilizing DER requirements calculated in the template, the planning engineer will also need to study and identify any needed system improvements required to integrate the DER into the system, i.e. substation/distribution improvements including improvements to mitigate any adverse effects the DER alternative and their costs. These costs can be added to the template on the solar or battery storage tabs as needed.

Results Summary
This tab is the starting point to identify the peak load and facility rating constraints that are driving the need for a potential traditional or DER alternative solution. From this information, a target loading (typically 90%) of the facility rating is determined. The next steps for analyzing the potential feasibility of a DER alternative are to proceed through the next tabs of the spreadsheet and provide information such as a projected peak daily load profile and solar output data for the site. The Results Summary tab also gathers key information from other tabs to present a synopsis of the initial screening to determine the feasibility of DER alternatives as solutions to the loading or voltage issue being investigated for a capital improvement.

Facility Load Data
This tab is used to add hourly load curve data for at least one day under "Existing Peak mm/dd/yyyy." If it is desired to review additional peak days and take an average, columns can be added to accomplish this. If you have load at other increments such as 10 min or 15 min data, use a separate Excel file to convert the data to hourly data. The load profile for Projected Peak is scaled based on % Increase compared to Existing Peak. The Projected Peak is the peak load when the load equals or exceeds the loading level that a Planning Criteria violation occurs.

PVWatts Data
This tab is used to populate the annual solar data that is obtained from running NREL's PVWatts Calculator Internet application for the site of the potential solar installation. The full annual data for the site is added to this tab. This base data is used on the following tab.

PVWatts Graph
This tab uses data from the PVWatts Data tab and averages the hourly monthly solar data for the months of July and August to create one 24 hour solar profile. If the peak for the facility being evaluated typically occurs outside the July and August window, the average calculations can be modified as needed for the specific site. (e.g. winter peaking load, fall peaking load). The graph shows output based on a percentage basis of the solar installation's MWdc nameplate. This graph is representative output for a potential solar installation and is used in conjunction with the daily load curve to determine the size of the installation needed to reduce the net load and solar output to below the target loading of the facility.

Solar Analysis
This tab is used to compare the hourly load profile and the solar output profile to determine if a solar DER alternative can result in lowering the load on the facility to the target 90% loading threshold.
1. To determine the minimum initial size of the solar installation to analyze first, it is calculated as: Min Solar Size (MW) = (Difference between Projected Peak and Target 90% Loading Threshold) x (Ratio DC Solar Panels to AC Inverter Output) / (Maximum %MWdc Nameplate Output).
2. Review the Solar Alternative graph to determine if a different size solar installation will result in the Net Load being below the Facility Rating Threshold.
3. If the Solar Alternative cannot meet the Facility Rating Threshold, then a Solar Only Alternative is not feasible.

Solar Summary & Cost Estimate

This tab is used to estimate the complete costs of a solar installation determined by the results of the Solar Analysis tab. Estimates for the solar array and inverter, land costs, and interconnection costs (substation and distribution system infrastructure required to connect the solar installation to the local utility grid) are included.

Battery Storage

1) If for some reason battery storage is not viable, regardless of cost, indicate in step one and briefly describe why it is not feasible.

2) The centralized energy storage requirements are calculated based on inputs on the 'Curve Data' tab of this workbook. The basic requirements for centralized energy storage (CES) include an MVA size for the peak discharge needed, and MVAhr for the energy needed. The MVA size is calculated by taking the forecasted load peak minus 90% of the loading constraint. The MVAhr requirement is calculated by determining the area under the forecasted load profile, bound by again 90% of the loading constraint. 90% is a management directive for the DER benefit expected. Verify the accuracy of the calculations by comparing the Loading Analysis chart and the CES requirements. Battery sizes (MVA and MVAhr) are rounded up for estimating purposes.

3) Based on the CES requirements, the template will calculate an estimate for the battery, installation, and ancillary costs. A maintenance cost is also included, as well as land costs based on typical battery sizes and information from the summary tab.

The planning engineer will need to determine the scope of the distribution and/or substation interconnection costs associated with installing battery storage and its location. The scope will inform the subsequent distribution /substation costs. The planning engineer will enter those costs into their respective distribution/substation cost cells.

If the battery size is not contained in the cost summary table, no cost will be returned, and the battery storage alternative is considered not feasible. Go to step 1 and document as 'No' not feasible with reasoning that required battery size is not a viable option. In addition, if there is insufficient off-peak charging time, cell J44 will return a "NO" and again go to step 1 and document as 'No' not feasible.

Solar & Battery Analysis

This tab is used to compare the hourly load profile, the solar output profile, and the needed battery output profile to determine if a combined solar and battery DER alternative can result in lowering the load on the facility to the target 90% loading threshold.

1. This analysis starts with the same MW size solar installation as the Solar Only Alternative since that MW size reduced the facility loading when the solar output was reasonably high.
2. This analysis estimates the capacity and energy of a battery needed to offset the Solar Deficit MW and Solar Deficit MWh values that the Solar Only Alternative could not provide.
3. The MW and MWh values estimated for the battery are rounded up to the next whole MW and/or MWh size. An hour duration that the battery is needed is also estimated. These values are used to create a cost estimate on the Solar & Battery Cost tab.
4. Review the Solar and Battery Alternative graph to determine if the calculated solar and battery installations result in the Net Load (orange) being below the Facility Rating Threshold (Green).
5. If the Solar and Battery Alternative cannot meet the Facility Rating Threshold (Green) and also provide enough capacity to charge the Battery, then a Solar and Battery Alternative may not be feasible.

A copy of the tab can be made to try different sized solar and battery installations that may be feasible and at a lower estimated cost. For combined installations where the battery charging time was adequate, smaller MW solar installations with larger MW and MWh battery installations can be modeled to potentially determine a potential alternative with a lower overall cost. For combined installations where the battery charging time was not adequate, larger MW solar installations to reduce the load on the transformer can be modeled to potentially determine a potential alternative.

Solar & Battery Summary & Cost Estimate

This tab is used to estimate the complete costs of a solar and battery installation determined by the results of the Solar & Battery Analysis tab. The calculations are the same as used on the individual Solar Cost and Battery tabs and totaled for a combined estimate.

Demand Side Management

Demand Side Management - PacifiCorp

1) At PacifiCorp, given the regulatory approvals and administrative requirements surrounding typical DSM applications, at least three years is needed to plan and implement a DSM solution. If the proposed project issue year is less than three years, then the DSM alternative is considered not feasible.. If the issue year is more than 3 years, proceed.

2) Enter the requested data sets for the equipment that would be affected by a reduction in load, e.g. for a substation transformer loading issue, enter the number of customers served by that transformer, the customer class, and MW reduction needed each year to stay below the loading constraint. This information will be utilized to estimate the available MWs of DSM served by that transformer.

3) Enter data from look up tables to finish the calculation.

4) Compare the available kW on the equipment with constraint issue to the needed reduction in load to stay below the constraint. If the values are within +/- 25% at any point along the accumulation outside of three years, further evaluation will be required by the DSM team. Contact Jeff Bumgardner in Pacific Power or Clay Monroe in Rocky Mountain Power. The available kW and costs information will be transferred to the summary tab. Enter 'Yes' that this option is feasible in cell J43. If the values are greater or less than 25%, this option is not feasible, enter 'No' in cell J43.

Results Summary of DER Alternatives compared to Traditional Alternatives

Load Projections

Enter Existing Peak	8.00	MW	Enter applicable peak load of the facility being evaluated from SCADA or other data source.
Enter Base Year	2016		Base year. Typically, the year of the load read.
Enter Growth Rate	1.00%	%	Enter applicable % annual growth rate. Below, add known new spot loads not included in growth rate.

	Year 1 2017	Year 2 2018	Year 3 2019	Year 4 2020	Year 5 2021	Year 6 2022	Year 7 2023	Year 8 2024	Year 9 2025	Year 10 2026
Load w/ growth rate	8.17	8.34	8.52	8.70	8.90	9.09	9.29	9.50	9.72	9.94
Known new loads	-			-	-	-	-	-	-	-
Total Load Estimate	8.17	8.34	8.52	8.70	8.90	9.09	9.29	9.50	9.72	9.94

Determination of Projected Peak and Initial Determination of Minimum DER MWac Output needed to achieve Target Facility Loading

Enter Facility Rating	Enter % Planning Criteria Loading	Planning Criteria Loading	Projected Peak when Load equals or exceeds Planning Criteria	% Increase from Existing Peak to Projected Peak	Enter Target Loading of Facility w/ DER	Target Facility Loading w/ DER	Minimum DER MW_{ac} Output based on Projected Peak that equals or exceeds Planning Criteria
8.40	100%	8.40	8.52	6.5%	90%	7.56	0.96

Base Assumptions

Minimum DER MWac Output based on Planning Criteria Loading		0.96	DER MWac
Safety Margin for minimum DER MWac Output (Default is 10%)	10%	1.06	DER MWac
(Note: This does not necessarily match the actual rating of the DER Alternative needed to achieve a Target Facility Loading)			
Property Cost per Acre Estimate		$50,000.00	$ Estimate

Solar Only Alternative

Is Solar Alternative possible?			No	Yes/No?
Solar Size Assumption	1.60	DER MWac	1.44	DER MWdc
Solar Land Assumption			10.97	acres
Summary Cost Estimate for Solar Only Alternative			$ 3,435,424	$ Estimate

Battery Only Alternative

Is Battery Alternative possible?	Yes	Yes/No?
Peak MW	1.00	MVA
Peak MWh	2.00	MVAh
Summary Cost Estimate for Battery Only Alternative	$ 2,309,105	$ Estimate

Solar & Battery Alternative

Is Solar & Battery Alternative possible?			Yes	Yes/No?
Peak Solar MW (use formula to refer to cell on Solar & Battery tab)	1.60	DER MWac	1.44	DER MWdc
Solar Land Assumption			10.97	acres
Summary Cost Estimate for Solar Portion			$ 3,435,424	$ Estimate
Peak Battery MW (use formula to refer to cell on Solar & Battery tab)			1.00	MW
Peak Battery MWh (use formula to refer to cell on Solar & Battery tab)			2.00	MWh
Summary Cost Estimate for Battery Portion (use formula to refer to cell on Solar & Battery tab)			$ 2,161,837	$ Estimate
Summary Cost Estimate for Solar & Battery Alternative (use formula to refer to cell on Solar & Battery tab)			$ 5,597,260	$ Estimate

: Printing: Select appropriate Company DSM summary by collapsing the other Company DSM summaries.

DSM Alternative

Is DSM Alternative possible?	No	
Potential load control available (kW)	30	kW
Summary Cost Estimate for DSM Alternative	$ 3,513	$ Estimate

Traditional Alternative

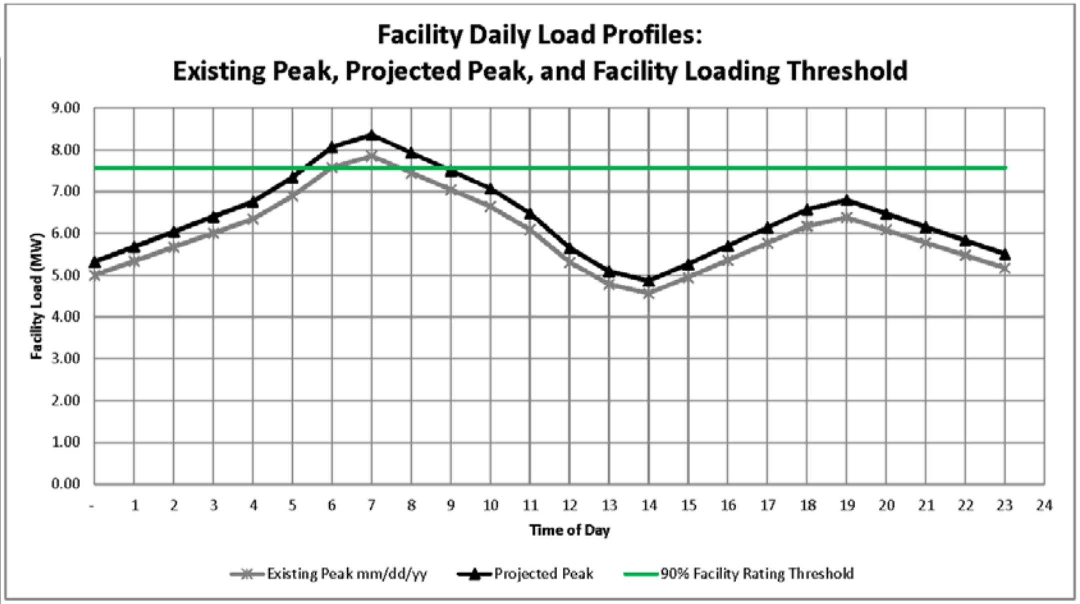
Load balancing, load swapping, and or reconductor.

Summary Cost Estimate for Traditional Alternative	150,000	$ Estimate

Facility Load Profile Data

This tab is used to add hourly load curve data for at least one day under "Existing Peak mm/dd/yyyy." If it is desired to review additional peak days and take an average, columns can be added to accomplish this. If you have load at other increments such as 10 min or 15 min data, use a separate Excel file to convert the data to hourly data. The load profile for Projected Peak is scaled based on % Increase compared to Existing Peak. The Projected Peak is the peak load when the load equals or exceeds the loading level that a Planning Criteria violation occurs.

		% Increase from Existing Peak to Projected Peak			
		6.5%			
	Max	Max			
	8.00	8.52	8.40		
Hour of Day	**Existing Peak mm/dd/yy**	**Projected Peak**	**% Facility Rating**	**90% Facility Rating Threshold**	**MW above Threshold**
-	4.99	5.32	63.3%	7.56	(2.24)
1	5.33	5.68	67.6%	7.56	(1.88)
2	5.67	6.04	71.9%	7.56	(1.52)
3	6.01	6.40	76.1%	7.56	(1.16)
4	6.34	6.75	80.4%	7.56	(0.81)
5	6.89	7.34	87.4%	7.56	(0.22)
6	7.57	8.06	96.0%	7.56	0.50
7	7.84	8.35	99.4%	7.56	0.79
8	7.44	7.93	94.3%	7.56	0.37
9	7.04	7.50	89.3%	7.56	(0.06)
10	6.64	7.07	84.2%	7.56	(0.49)
11	6.08	6.48	77.1%	7.56	(1.08)
12	5.30	5.65	67.2%	7.56	(1.91)
13	4.78	5.09	60.6%	7.56	(2.47)
14	4.57	4.86	57.9%	7.56	(2.70)
15	4.94	5.26	62.7%	7.56	(2.30)
16	5.35	5.70	67.9%	7.56	(1.86)
17	5.76	6.14	73.0%	7.56	(1.42)
18	6.17	6.57	78.2%	7.56	(0.99)
19	6.38	6.80	80.9%	7.56	(0.76)
20	6.08	6.47	77.1%	7.56	(1.09)
21	5.78	6.15	73.2%	7.56	(1.41)
22	5.47	5.83	69.4%	7.56	(1.73)
23	5.17	5.51	65.5%	7.56	(2.05)



PACIFIC POWER
A DIVISION OF PACIFICORP

Solar MW Output Data for Use in DER Alternative Evaluation from NREL's PVWatts Calculator

This step uses the initial annual solar data from NREL's PVWatts Internet application and converts it to average hourly data from the months of July and August (see PVWatts Graph tab).

1. PVWatts uses available solar data, so very general site information is needed, typically just the city and state.
   Note: Solar data is not available everywhere. Use nearest available solar data or a combination of locations.
2. Go to this NREL solar data link and enter relevant site information for potential solar installation: http://pvwatts.nrel.gov/
3. After running the calculator for the potential solar site, select downloading the Annual Hourly Data from PVWatts and save it to an Excel file. (Do not choose the monthly data selection)
4. Copy the annual data from the Excel file and do two separate **"Paste Special: Values Only" of the information to this tab starting in Cell C16 for the top data and then in in Cell C33.**
5. This step provides initial annual solar data.
6. The data on this tab is used to calculate average hourly data from the months of July and August. The average data and graph for the July-August time period is on the PVWatts Graph tab
7. If the peak for facility being evaluated typically occurs outside the July and August window, the calculations can be modified as needed for the site. (e.g. winter peaking load, fall peaking load)

der: Please do two separate Paste Special Values Only to avoid pasting over the explanations in F16 through F31

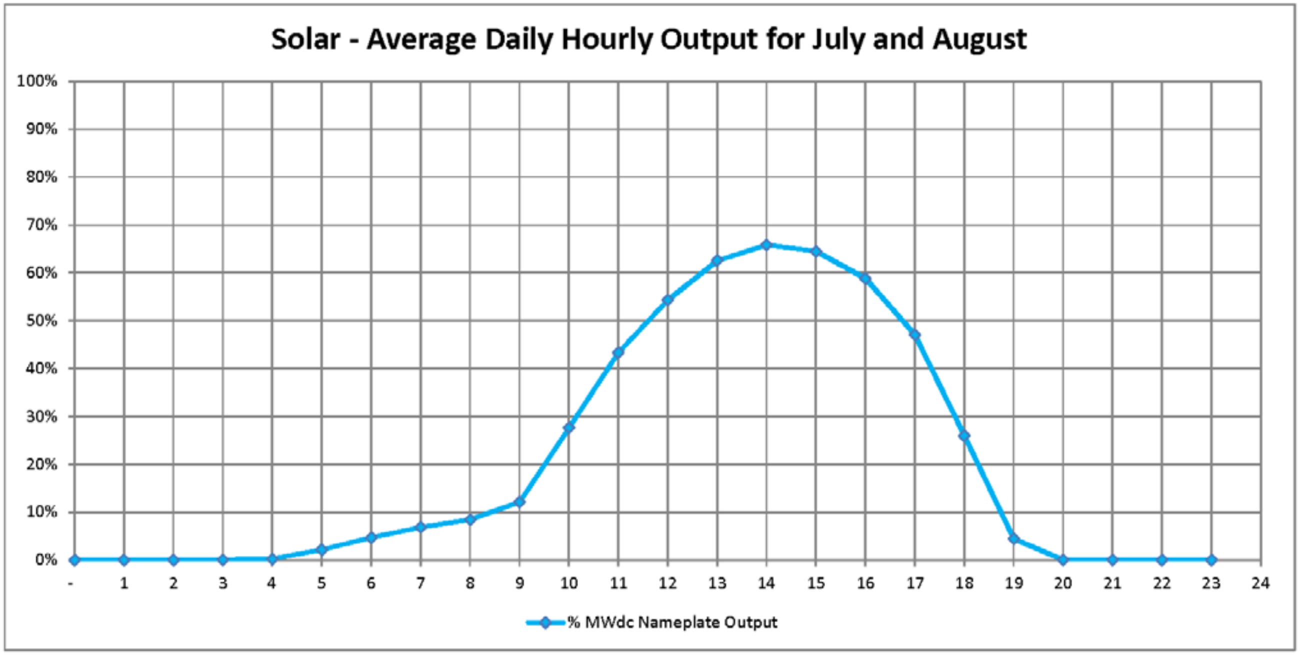
PVWatts: Hourly PV Performance Data		**In the PVWatts Calculator. enter site specific information and use default information as needed**
Requested Location:	**REDMOND, OR**	**Enter Site Location: City, State. Use nearest available solar data or a combination of locations.**
Location:		Location Specific
Lat (deg N):	44.27	Populated from Location Specific from the City, State and Weather Location selected
Long (deg W):	121.15	Populated from Location Specific from the City, State and Weather Location selected
Elev (m):	940	Populated from Location Specific from the City, State and Weather Location selected
DC System Size (kW):	**10**	**Enter 10 kW. This value or percentage output is later scaled by amount needed for DER Alternative**
Module Type:	Standard	Default Selection
Array Type:	Fixed (open rack)	Default Selection
Array Tilt (deg):	**45**	**Enter 45 for initial selection. Depending on location and of time peak load, varying this value improves aligning solar output to peak.**
Array Azimuth (deg):	**270**	**Enter 270. West Facing: West typically provides higher capacity later in day to match a typical peak time. Adjust if facility peak is earlie**
System Losses:	14	Default Selection
Invert Efficiency:	96	Default Selection
DC to AC Size Ratio:	1.1	Default Selection
Average Cost of Electricity Purchased from Utility ($/kWh):	0.1	Default Selection
Initial Cost	3.3	Default Selection
Cost of Electricity Generated by System ($/kWh):	0.25	Default Selection

Month	Day	Hour	Beam Irradiance (W/m^2)	Diffuse Irradiance (W/m^2)	Ambient Temperature (C)	Wind Speed (m/s)	Plane of Array Irradiance (W/m^2)	Cell Temperature (C)	**DC Array Output (W)**	AC System Output (W)

Solar Output in Summer - Calculation of Average Daily Hourly Data Jan

This tab uses data from the PVWatts Data tab and averages the hourly monthly solar data for the months of July and August to create one 24 hour solar profile. If the peak for facility being evaluated typically occurs outside the July and August window, the calculations can be modified as needed for the specific site. (e.g. winter peaking load, fall peaking load). The graph shows output based on a percentage basis of the solar installation's MWdc nameplate.

	Base Wdc of Solar Site	
	10,000	Max
		65.84%
Hour of Day	DC Output (W)	% MWdc Nameplate Output
-	-	0.00%
1	-	0.00%
2	-	0.00%
3	-	0.00%
4	25	0.25%
5	214	2.14%
6	468	4.68%
7	683	6.83%
8	841	8.41%
9	1,214	12.14%
10	2,763	27.63%
11	4,335	43.35%
12	5,433	54.33%
13	6,256	62.56%
14	6,584	65.84%
15	6,449	64.49%
16	5,879	58.79%
17	4,705	47.05%
18	2,593	25.93%
19	441	4.41%
20	-	0.00%
21	-	0.00%
22	-	0.00%
23	-	0.00%



Solar Alternative Analysis

This tab is used to compare the hourly load profile and the solar output profile to determine if a solar DER alternative can result in lowering the load on the facility to the target 90% loading threshold.

1. To determine the minimum initial size of the solar installation to analyze first, Cell I15 calculates: Min Solar Size (MW) = (Difference between Projected Peak and Target 90% Loading Threshold) x (Ratio DC Solar Panels to AC Inverter Output) / (Maximum %MWdc Nameplate Output from the solar curve).
2. Review the Solar Alternative graph to determine if a solar installation will result in the Net Load (purple) being below the Facility Rating Threshold (Green). Try additional MW sizes in case a larger size works.
3. If the Solar Alternative cannot meet the Facility Rating Threshold (Green), then a Solar Only Alternative is not feasible.
4. Is Solar Alternative feasible? No Yes/No?

Load Information

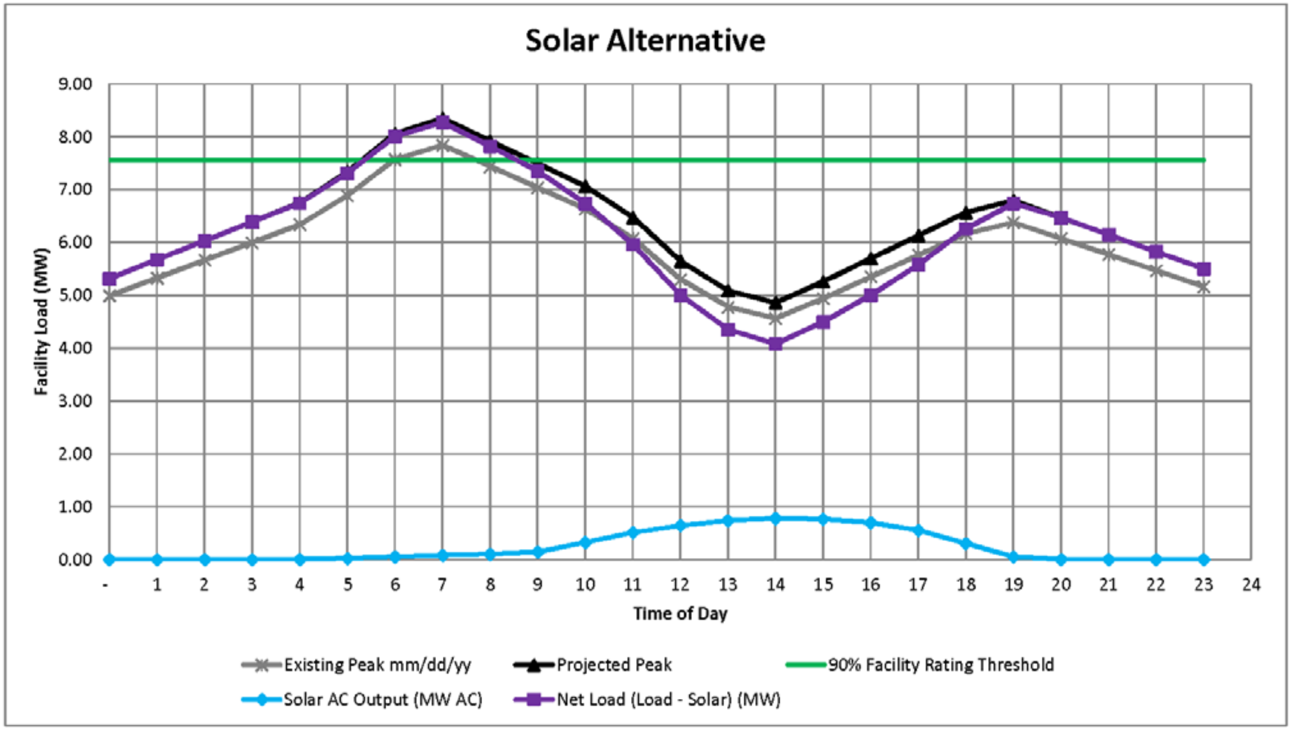
% Increase from Existing Peak to Projected Peak: 6.5%

Solar Information

0.96 = Minimum DER MWac Output based on Projected Peak that equals or exceeds Planning Criteria

0.9 = Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 0.9)

	Max	Max				Max	Min Solar Size (MW)								Sum		Sum
	8.00	8.52	8.40			65.84%	1.31								5.54		1.43
Hour of Day	**Existing Peak mm/dd/yy**	**Projected Peak**	**% Facility Rating**	**90% Facility Rating Threshold**	**MW above Threshold**	**% MWdc Nameplate Output**	**Solar DC Output (MW DC)**	**Solar AC Output (MW AC)**	**Net Load (Load - Solar) (MW)**	**Load > 90% of Facility Rating?**	**Spare Solar Raw (MW)**	**Solar Deficit (MW)**	**Spare Solar (MW)**	**Spare Solar MWh**	**Spare Solar MWh (Total)**	**Inc Solar Deficit MWh**	**Solar Deficit MWh (Total)**
-	4.99	5.32	63.3%	7.56	(2.24)	0.00%	-	-	5.32	-	-	-	-	-	-	-	-
1	5.33	5.68	67.6%	7.56	(1.88)	0.00%	-	-	5.68	-	-	-	-	-	-	-	-
2	5.67	6.04	71.9%	7.56	(1.52)	0.00%	-	-	6.04	-	-	-	-	-	-	-	-
3	6.01	6.40	76.1%	7.56	(1.16)	0.00%	-	-	6.40	-	-	-	-	-	-	-	-
4	6.34	6.75	80.4%	7.56	(0.81)	0.25%	0.00	0.00	6.75	-	0.00	-	0.00	0.00	0.00	-	-
5	6.89	7.34	87.4%	7.56	(0.22)	2.14%	0.03	0.03	7.31	-	0.03	-	0.03	0.01	0.02	-	-
6	7.57	8.06	96.0%	7.56	0.50	4.68%	0.06	0.06	8.01	1	(0.45)	0.45	-	0.01	0.03	0.22	0.22
7	7.84	8.35	99.4%	7.56	0.79	6.83%	0.09	0.08	8.27	1	(0.71)	0.71	-	-	0.03	0.58	0.81
8	7.44	7.93	94.3%	7.56	0.37	8.41%	0.11	0.10	7.83	1	(0.27)	0.27	-	-	0.03	0.49	1.29
9	7.04	7.50	89.3%	7.56	(0.06)	12.14%	0.16	0.14	7.35	-	0.14	-	0.14	0.07	0.10	0.13	1.43
10	6.64	7.07	84.2%	7.56	(0.49)	27.63%	0.36	0.33	6.74	-	0.33	-	0.33	0.23	0.33	-	1.43
11	6.08	6.48	77.1%	7.56	(1.08)	43.35%	0.57	0.51	5.97	-	0.51	-	0.51	0.42	0.75	-	1.43
12	5.30	5.65	67.2%	7.56	(1.91)	54.33%	0.71	0.64	5.01	-	0.64	-	0.64	0.58	1.33	-	1.43
13	4.78	5.09	60.6%	7.56	(2.47)	62.56%	0.82	0.74	4.35	-	0.74	-	0.74	0.69	2.02	-	1.43
14	4.57	4.86	57.9%	7.56	(2.70)	65.84%	0.86	0.78	4.09	-	0.78	-	0.78	0.76	2.78	-	1.43
15	4.94	5.26	62.7%	7.56	(2.30)	64.49%	0.85	0.76	4.50	-	0.76	-	0.76	0.77	3.55	-	1.43
16	5.35	5.70	67.9%	7.56	(1.86)	58.79%	0.77	0.69	5.01	-	0.69	-	0.69	0.73	4.28	-	1.43
17	5.76	6.14	73.0%	7.56	(1.42)	47.05%	0.62	0.56	5.58	-	0.56	-	0.56	0.62	4.90	-	1.43
18	6.17	6.57	78.2%	7.56	(0.99)	25.93%	0.34	0.31	6.26	-	0.31	-	0.31	0.43	5.33	-	1.43
19	6.38	6.80	80.9%	7.56	(0.76)	4.41%	0.06	0.05	6.74	-	0.05	-	0.05	0.18	5.51	-	1.43
20	6.08	6.47	77.1%	7.56	(1.09)	0.00%	-	-	6.47	-	-	-	-	0.03	5.54	-	1.43
21	5.78	6.15	73.2%	7.56	(1.41)	0.00%	-	-	6.15	-	-	-	-	-	5.54	-	1.43
22	5.47	5.83	69.4%	7.56	(1.73)	0.00%	-	-	5.83	-	-	-	-	-	5.54	-	1.43
23	5.17	5.51	65.5%	7.56	(2.05)	0.00%	-	-	5.51	-	-	-	-	-	5.54	-	1.43



Solar Alternative
Facility Load (MW)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Time of Day
Existing Peak mm/dd/yy
Projected Peak
90% Facility Rating Threshold
Solar AC Output (MW AC)
Net Load (Load - Solar) (MW)

Solar Only Alternative Summary and Cost Estimate

Is Solar Only Alternative feasible?		No	Yes/No?
Note: Even if the alternative is not feasible at this stage, continue with the following to develop a cost comparison to show relative costs.			
1) PV Solar Electrical Sizing (DC) (from Results Summary and Solar Analysis tabs)			
DER MWac based on Projected Load Estimate		0.96	DER MWac
Safety Margin for Projected Size and Resulting DER MWac (Default is 10%)	10%	1.06	DER MWac
DER MWac based on Projected Load Estimate and the Average Solar Output for July & August	65.84%	1.60	DER MWac
Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 1.1)	0.9	1.44	DER MWdc
2) Land Requirements			
Next we calculate the size of land required for MWdc plant size calculated above.	acres/MWdc		
Array Area (Land required. Default assumption is 7.6 acres/MWdc based on NREL study)	7.6	10.97	acres
3) Cost Estimate			
Solar PV Costs	$/MWdc		
Cost of Solar PV array (default $2M / MWdc)	$ 2,000,000	$ 2,886,911	$
Lands Costs	$/acre		
Lands acquisition costs	$ 50,000	$ 548,513	$
Interconnection Costs:			
Substation Costs			
Feeder Breaker Addition	$ -		$
SCADA/Telecom	$ -		$
Subtotal		$ -	$
Distribution Feeder Costs			
New feeder	$ -		$
Feeder extension	$ -		$
Metering	$ -		$
Subtotal		$ -	$
Summary Cost Estimate for Solar Alternative		$ 3,435,424	$ Total

Energy Storage Only Alternative

1) Is battery storage a feasible alternative? Yes

Provide a brief description if not feasible:

2) Determine Battery requirements:

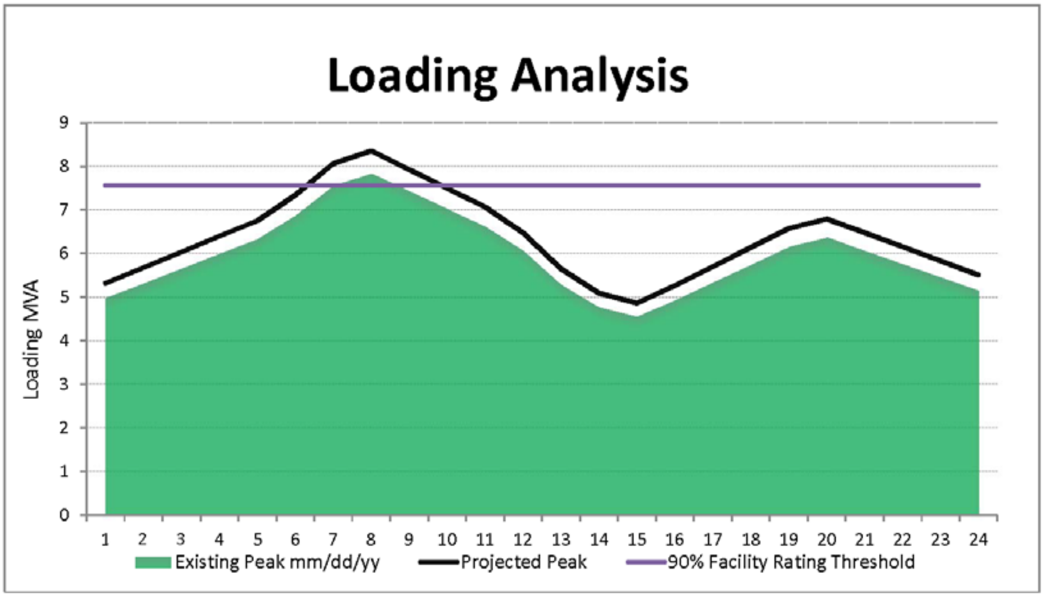
Forecasted Growth %:	**6%**	Value from the Summary tab
Loading Constraint (MVA):	**8.52**	Value from the Summary tab
Target Facility Loading w/ DER:	**7.56**	Value from the Summary tab

Time	Existing Peak mm/dd/yy	Projected Peak	Need for DER (MVA)	MVAHrs Needed	90% Facility Rating Threshold
0	4.99	5.32	-2.24	-2.06	7.56
1	5.33	5.68	-1.88	-1.70	7.56
2	5.67	6.04	-1.52	-1.34	7.56
3	6.01	6.40	-1.16	-0.99	7.56
4	6.34	6.75	-0.81	-0.51	7.56
5	6.89	7.34	-0.22	0.14	7.56
6	7.57	8.06	0.50	0.65	7.56
7	7.84	8.35	0.79	0.58	7.56
8	7.44	7.93	0.37	0.15	7.56
9	7.04	7.50	-0.06	-0.28	7.56
10	6.64	7.07	-0.49	-0.79	7.56
11	6.08	6.48	-1.08	-1.50	7.56
12	5.30	5.65	-1.91	-2.19	7.56
13	4.78	5.09	-2.47	-2.58	7.56
14	4.57	4.86	-2.70	-2.50	7.56
15	4.94	5.26	-2.30	-2.08	7.56
16	5.35	5.70	-1.86	-1.64	7.56
17	5.76	6.14	-1.42	-1.21	7.56
18	6.17	6.57	-0.99	-0.88	7.56
19	6.38	6.80	-0.76	-0.93	7.56
20	6.08	6.47	-1.09	-1.25	7.56
21	5.78	6.15	-1.41	-1.57	7.56
22	5.47	5.83	-1.73	-1.89	7.56
23	5.17	5.51	-2.05	-1.03	7.56

	MVA	MVAHrs	Duration(hrs)
Battery Requirement:	1.00	2.00	2

Sufficient Charging Time? **YES**

If "no", go to step 1 and enter "No"



3) Determine cost of the battery storage system

	Estimate $
Battery System	$2,000,000
Civil Work	$80,000
Property Cost	$24,105
Distribution Costs	$75,000
Substation Costs	$0
Maintenance Contract (10 yrs)	$130,000
Total	$2,309,105

Cost Table - Derived from PAC Estimating Tool

Duration (hrs)	Power Rating (MVA) 1	2	3	4	5
1	1.4	2.4	3.4	4.4	5.4
2	2	3.6	5.2	6.8	8.4
3	2.6	4.8	7	9.2	11.4
4	3.2	6	8.8	11.6	14.4
5	3.8	7.2	10.6	14	17.4
6	4.4	8.4	12.4	16.4	20.4
7	5	9.6	14.2	18.8	23.4
8	5.5	10.7	16	21.2	26.4

Solar and Battery Alternative Analysis

This tab is used to compare the hourly load profile to the combination of the solar output profile and a battery to determine if a solar and battery combined DER alternative can result in lowering the load on the facility to the target 90% loading threshold.

Load Information

% Increase from Existing Peak to Projected Peak: 6.5%

Solar Information

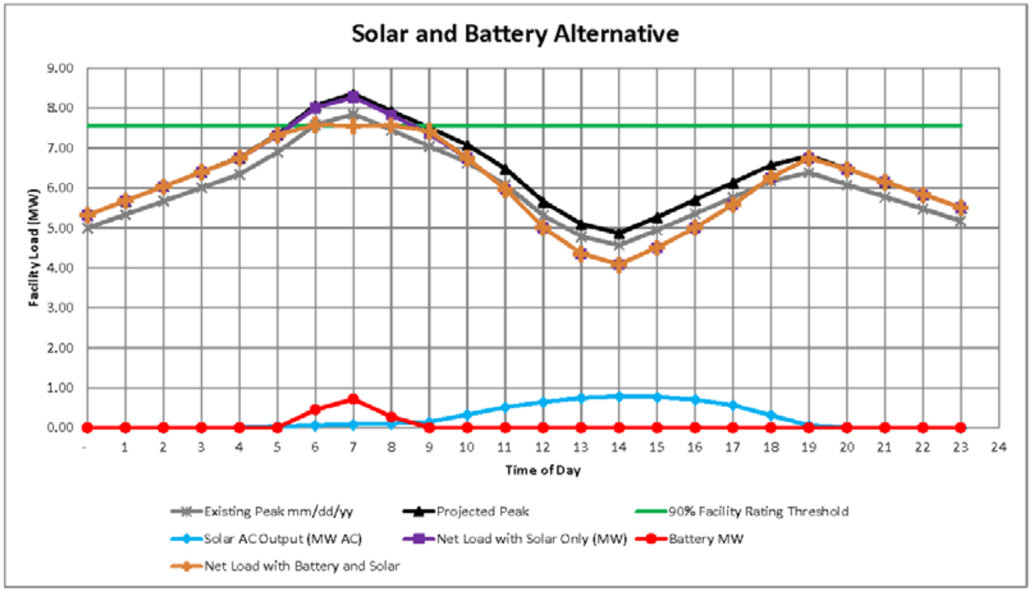
0.96 = Minimum DER MWac Output based on Projected Peak that equals or exceeds Planning Criteria

0.9 = Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 0.9)

Battery Information

Discharge Eff	Charge Eff	
0.95	0.95	= Default Efficiencies
Battery MW	**Battery Duration Hrs**	
1.00	2	

	Max	Max				Max	Min Solar Size (MW)								Sum		Sum	Battery MWh			
	8.00	8.52	8.40			65.84%	1.31								5.54		1.43	2.00	1.60		
Hour of Day	**Existing Peak mm/dd/yy**	**Projected Peak**	**% Facility Rating**	**90% Facility Rating Threshold**	**MW above Threshold**	**% MWdc Nameplate Output**	**Solar DC Output (MW DC)**	**Solar AC Output (MW AC)**	**Net Load with Solar Only (MW)**	**Load > 90% of Facility Rating?**	**Spare Solar Raw (MW)**	**Solar Deficit (MW)**	**Spare Solar (MW)**	**Spare Solar MWh**	**Spare Solar MWh (Total)**	**Inc Solar Deficit MWh**	**Solar Deficit MWh (Total)**	**Battery Size Needed**	**Solar Needed to Charge Battery**	**Net Load with Battery and Solar**	**Charge Battery with Spare Solar MWh**
-	4.99	5.32	63.3%	7.56	(2.24)	0.00%	-	-	5.32	-	-	-	-	-	-	-	-	-	-	5.32	-
1	5.33	5.68	67.6%	7.56	(1.88)	0.00%	-	-	5.68	-	-	-	-	-	-	-	-	-	-	5.68	-
2	5.67	6.04	71.9%	7.56	(1.52)	0.00%	-	-	6.04	-	-	-	-	-	-	-	-	-	-	6.04	-
3	6.01	6.40	76.1%	7.56	(1.16)	0.00%	-	-	6.40	-	-	-	-	-	-	-	-	-	-	6.40	-
4	6.34	6.75	80.4%	7.56	(0.81)	0.25%	0.00	0.00	6.75	-	0.00	-	0.00	0.00	0.00	-	-	-	-	6.75	0.00
5	6.89	7.34	87.4%	7.56	(0.22)	2.14%	0.03	0.03	7.31	-	0.03	-	0.03	0.01	**0.02**	-	-	-	-	**7.33**	**0.02**
6	7.57	8.06	96.0%	7.56	0.50	4.68%	0.06	0.06	8.01	1	(0.45)	0.45	-	0.01	**0.03**	0.22	0.22	0.24	0.25	**7.57**	**0.03**
7	7.84	8.35	99.4%	7.56	0.79	6.83%	0.09	0.08	8.27	1	(0.71)	0.71	-	-	**0.03**	0.58	0.81	0.85	0.89	**7.56**	**0.03**
8	7.44	7.93	94.3%	7.56	0.37	8.41%	0.11	0.10	7.83	1	(0.27)	0.27	-	-	**0.03**	0.49	1.29	1.36	1.43	**7.56**	**0.03**
9	7.04	7.50	89.3%	7.56	(0.06)	12.14%	0.16	0.14	7.35	-	0.14	-	0.14	0.07	**0.10**	0.13	1.43	1.50	1.58	**7.43**	**0.10**
10	6.64	7.07	84.2%	7.56	(0.49)	27.63%	0.36	0.33	6.74	-	0.33	-	0.33	0.23	0.33	-	1.43	1.50	1.58	6.74	
11	6.08	6.48	77.1%	7.56	(1.08)	43.35%	0.57	0.51	5.97	-	0.51	-	0.51	0.42	0.75	-	1.43	1.50	1.58	5.97	
12	5.30	5.65	67.2%	7.56	(1.91)	54.33%	0.71	0.64	5.01	-	0.64	-	0.64	0.58	1.33	-	1.43	1.50	1.58	5.01	
13	4.78	5.09	60.6%	7.56	(2.47)	62.56%	0.82	0.74	4.35	-	0.74	-	0.74	0.69	2.02	-	1.43	1.50	1.58	4.35	
14	4.57	4.86	57.9%	7.56	(2.70)	65.84%	0.86	0.78	4.09	-	0.78	-	0.78	0.76	2.78	-	1.43	1.50	1.58	4.09	
15	4.94	5.26	62.7%	7.56	(2.30)	64.49%	0.85	0.76	4.50	-	0.76	-	0.76	0.77	3.55	-	1.43	1.50	1.58	4.50	
16	5.35	5.70	67.9%	7.56	(1.86)	58.79%	0.77	0.69	5.01	-	0.69	-	0.69	0.73	4.28	-	1.43	1.50	1.58	5.01	
17	5.76	6.14	73.0%	7.56	(1.42)	47.05%	0.62	0.56	5.58	-	0.56	-	0.56	0.62	4.90	-	1.43	1.50	1.58	5.58	
18	6.17	6.57	78.2%	7.56	(0.99)	25.93%	0.34	0.31	6.26	-	0.31	-	0.31	0.43	5.33	-	1.43	**1.50**	1.58	**6.26**	
19	6.38	6.80	80.9%	7.56	(0.76)	4.41%	0.06	0.05	6.74	-	0.05	-	0.05	0.18	5.51	-	1.43	**1.50**	1.58	**6.74**	
20	6.08	6.47	77.1%	7.56	(1.09)	0.00%	-	-	6.47	-	-	-	-	0.03	5.54	-	1.43	**1.50**	1.58	**6.47**	
21	5.78	6.15	73.2%	7.56	(1.41)	0.00%	-	-	6.15	-	-	-	-	-	5.54	-	1.43	**1.50**	1.58	6.15	
22	5.47	5.83	69.4%	7.56	(1.73)	0.00%	-	-	5.83	-	-	-	-	-	5.54	-	1.43	1.50	1.58	5.83	
23	5.17	5.51	65.5%	7.56	(2.05)	0.00%	-	-	5.51	-	-	-	-	-	5.54	-	1.43	1.50	1.58	5.51	
																	1.50	1.60	1.60	Rounded to tenths place	
																	2.00	2.00	2.00	Rounded to ones place	


Solar and Battery Alternative
Facility Load (MW)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Time of Day
Existing Peak mm/dd/yy
Projected Peak
90% Facility Rating Threshold
Solar AC Output (MW AC)
Net Load with Solar Only (MW)
Battery MW
Net Load with Battery and Solar

Solar and Battery Alternative Summary and Cost Estimate

Is Solar and Battery Alternative feasible?		Yes	Yes/No?
Note: Even if the alternative is not feasible at this stage, continue with the following to develop a cost comparison to show relative costs.			
Solar Portion			
1) PV Solar Electrical Sizing (DC) (from Results Summary and Solar Analysis tabs)			
DER MWac based on Projected Load Estimate		0.96	DER MWac
Safety Margin for Projected Size and Resulting DER MWac (Default is 10%)	10%	1.06	DER MWac
DER MWac based on Projected Load Estimate and the Average Solar Output for July & August	65.84%	1.60	DER MWac
Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 1.1)	0.9	1.44	DER MWdc
2) Solar Land Requirements			
Next we calculate the size of land required for MWdc plant size calculated above.	acres/MWdc		
Array Area (Land required. Default assumption is 7.6 acres/MWdc based on NREL study)	7.6	10.97	acres
3) Solar Cost Estimate			
Solar PV Costs	$/MWdc		
Cost of Solar PV array (default $2M / MWdc)	$ 2,000,000	$ 2,886,911	$
Land Costs	$/acre		
Land acquisition costs	$ 50,000	$ 548,513	$
Interconnection Costs:			
Substation Costs			
Feeder Breaker Addition	$ -		$
SCADA/Telecom	$ -		$
Subtotal		$ -	$
Distribution Feeder Costs			
New feeder	$ -		$
Feeder extension	$ -		$
Metering	$ -		$
Subtotal		$ -	$
Summary Cost Estimate for Solar Portion of Alternative		$ 3,435,424	$ Subtotal

PacifiCorp
Demand Side Management
Direct Load Control and Energy Efficiency

1) If the project in-service date is less than 3 years from the projected approval date, DSM is considered infeasible. Enter 'No' in Step 4, Cell J54
If project in-service date is greater than 3 years continue.

2) Enter the following information sets:

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak shaving requirements (MW)										
Peak shaving requirements cumulative (MW)										

Winter or Summer Peaking:	Winter
State:	Oregon
# of Customers Impacted:	1150

Customers Impacted By Class

Industrial	Commercial	Residential	Irrigation
0	50	1100	

3) Using DSM input tables, look up corresponding state and customer class and enter the kw available per customer and cost per kw.

	Industrial	Commercial	Residential	Irrigation
kw per customer	65.327	0.294	0.014	0.000
kw available	0.00	14.68	15.78	0.00
cost per kw	$76.00	$76.00	$152.00	
Cost for impacted	$0.00	$1,115.50	$2,397.87	$0.00

4) Compare the total kw available to the total cumulative peak shaving requirement. If available kw is within +/-25% of the requirement, forward worksheet to DSM group for further analysis.

30 Total kW Available

$3,513 Total Cost

Is it feasible to achieve the needed MW from this DSM Alternative? No Yes/No?

DSM Inputs:

Customer Class Counts:

	Industrial	Commercial	Residential	Irrigation
Utah	432	101,276	758,875	3,158
Wyoming	123	27,507	113,563	796
Idaho	19	10,535	60,695	5,010
Oregon	199	88,570	488,100	8,089
Washingto	66	20,410	105,735	5,219
California	18	8,361	35,507	2,039

Total DLC (kw) available per customer

	Summer Products				Winter Products			
Regions:	Industrial	Commercial	Residential	Irrigation	Industrial	Commercial	Residential	Irrigation
Utah	92.593	0.563	0.083	6.016	113.426	0.474	0.000	0.000
Wyoming	325.203	0.291	0.044	1.256	325.203	0.291	0.018	0.000
Idaho	0.000	0.190	0.049	5.190	0.000	0.190	0.016	0.000
Oregon	65.327	0.294	0.051	1.113	65.327	0.294	0.014	0.000
Washingto	60.606	0.343	0.104	0.958	60.606	0.343	0.019	0.000
California	15.278	0.141	0.060	2.060	15.278	0.141	0.015	0.000

DLC Cost per kw

	Summer Products				Winter Products			
Regions:	Industrial	Commercial	Residential	Irrigation	Industrial	Commercial	Residential	Irrigation
Utah	$77.00	$77.00	$62.00	$52.00	$77.00	$77.00		
Wyoming	$78.00	$78.00	$131.00	$71.00	$78.00	$78.00	$131.00	
Idaho	$76.00	$76.00	$156.00	$51.00		$76.00	$156.00	
Oregon	$76.00	$76.00	$152.00	$71.00	$76.00	$76.00	$152.00	
Washingto	$76.00	$76.00	$134.00	$71.00	$76.00	$76.00	$134.00	
California	$74.00	$74.00	$116.00	$69.00	$74.00	$74.00	$116.00	

Total DLC (kw) available by state REFERENCE ONLY

	Summer Products				Winter Products			
Regions:	Industrial	Commercial	Residential	Irrigation	Industrial	Commercial	Residential	Irrigation
Utah	40,000	57,000	63,000	19,000	49,000	48,000		
Wyoming	40,000	8,000	5,000	1,000	40,000	8,000	2,000	
Idaho		2,000	3,000	26,000		2,000	1,000	
Oregon	13,000	26,000	25,000	9,000	13,000	26,000	7,000	
Washingto	4,000	7,000	11,000	5,000	4,000	7,000	2,000	
California	275	1,175	2,140	4,200	275	1,175	550	

2014 Conservation Potential Study - Class 1 Incremental (by 2034)

Weather adjusted 2014 sector sales data (kwh) used to split potential between C&I (excludes sales to special contract loads in UT and ID)

Appendix G – Distribution Substation Metering Technical Requirements

1) All installations will be engineered, prints issued, and as-builts processed.
2) Meters will use existing current and potential transformers.
3) Meters will use existing meter panel cutouts if available. Panel modification will be limited to hole drilling only. New panels or panel cutting will be avoided to control costs.
4) There will also be a design available where no convenient panel space is available, possible using transducer only versions of available meters.
5) The number of meter styles used will be held to a minimum to reduce training costs of meter and relay technicians.
6) Spares for the meters purchased will be available in stores for long-term support.
7) All meters will be configured to measure and record all three-phase quantities.
8) For installation without all three potentials available the meter will have ability to simulate the missing phases. The provided phase can be any phase available.
9) Meters will be configured so that that the recorded phases are consistent with system vectors.
10) Installed stand-alone meters will be easily upgradable so that they can be incorporated into SCADA if it becomes available at the metering point.
11) The meters will support DNP, 61850 Ethernet as well as have analog outputs.
12) Meters will have available at least six analog outputs.
    a. Meters will read and store internally per phase: kW, kVAR, current, power factor, frequency, accumulated energy, harmonics, and recorded waveforms generated when programed limits are exceeded.
    b. Meters need to have the ability to record waveforms of all phases at the same time.
13) Meters will have the ability to be read by cellular phone.
14) Stand-alone meters will have the ability to store all quantities for one a least one year. This is in case they are read on a periodic basis (i.e. monthly, quarterly, or yearly).
15) Ideally the meters would have an adjustable storage rate to allow for different storage rates bases upon the expected read interval.
16) Meters will have the ability for live and periodic data reads to be moved into MV90 so they can be transferred into the SCHOOL PI database.

Appendix H – Distribution Automation Candidate Sites

A list of potential candidate sites for distribution automation equipment to be deployed in Oregon is provided in Table 8.

Table 8 – Candidate Locations Identified for DA Equipment

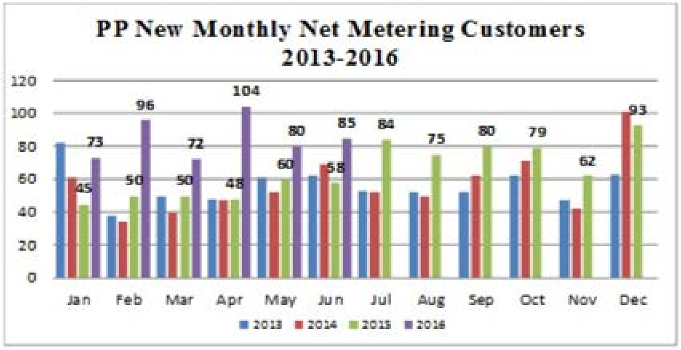
Operating Area	Substation Name	Feeder Name
Grants Pass	Agness	Jones Creek
Grants Pass	Caveman	Quail
Grants Pass	Caveman	Washington
Grants Pass	Caveman	Manzanita
Grants Pass	Caveman	Caveman
Grants Pass	Park Street	Express
Grants Pass	Park Street	Portola
Hood River	Hood River	Residential
Hood River	Hood River	North
Lincoln City	Devil's Lake	Ocean
Lincoln City	Devil's Lake	Lake
Lincoln City	Devil's Lake	Siuslaw
Medford	Belknap	Barnett
Medford	Brookhurst	Crater Lake
Medford	Brookhurst	Sunrise
Medford	Foothills	Hospital
Medford	Foothills	Pierce Road
Medford	White City	Avenue C
Madras	Cherry Lane	Seven Peaks
Portland	Alderwood	2
Portland	Columbia	1
Portland	Cully	3
Portland	Cully	1
Portland	Holladay	5
Portland	Holladay	6
Portland	Killingsworth	5
Portland	Killingsworth	4
Portland	Russellville	4
Portland	Russellville	2
Portland	Vernon	1
Roseburg	Cloake	RUSA
Roseburg	Garden Valley	Edenbower
Roseburg	Roseburg	Diamond
Roseburg	Winchester	Wilber
Stayton	Lyons	Mehama

Appendix I – Pacific Power Net Metering and Customer Generation

Monthly net metering and customer generation report for June 2016:

Customer Generation June 2016

Pacific Power enrollment increased by 85 customers, with 60 from Oregon, 18 from Washington, and seven from California.

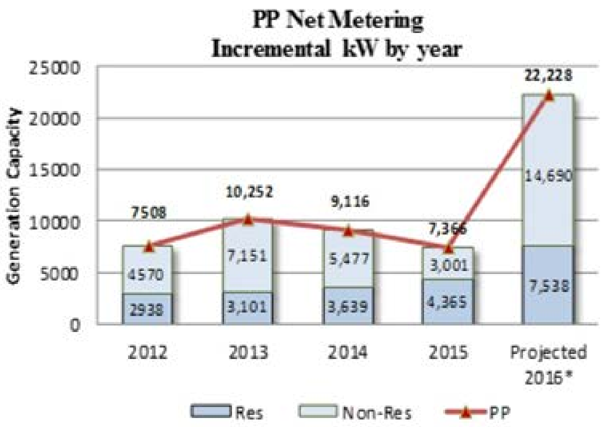


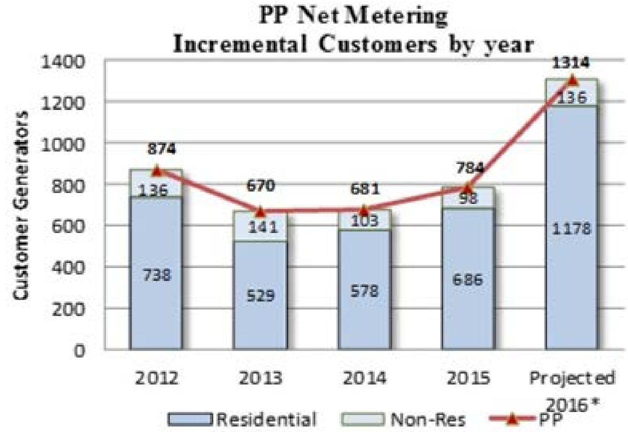
PP Cumulative Totals

As of July 6, 2016

State	Total Customers	Residential Customers	Non-Res Customers	Residential Size (kW)	Non-Res Size (kW)	Total Generation (kW)
CA	254	218	36	1,672	2,207	3,879
OR	4,903	4,135	768	18,795	27,611	46,406
WA	504	431	73	3,086	1,903	4,989
PP	**5,661**	**4,784**	**877**	**23,553**	**31,721**	**55,275**

Average Size of Residential System	4.9 kW
Average Size of Non-Residential System	36.2 kW





*Projection based on three month rolling average.