PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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August 1, 2017

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UM 1667—PacifiCorp's 2017 Smart Grid Report

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing with the Public Utility Commission of Oregon its 2017 Smart Grid Report in compliance with Order No. 13-279.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

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In addition, PacifiCorp respectfully requests that any information requests in this docket be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Informal questions concerning this filing may be directed to Natasha Siores at (503) 813-6583.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

cc: UM 1667 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of **PacifiCorp's 2017 Smart Grid Report** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 1st day of August, 2017.

Jennifer Angell
Supervisor, Regulatory Operations

Pacific Power Smart Grid Oregon Annual Report

2017 Report

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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
CIS ....Customer Information System
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
EMS………………………………….Energy Management System
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 2017 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. 16-476 in docket UM 1667.

Grid modernization is the application of advanced technology, communications, and controls to the power system, from generation, through transmission, distribution, to the customer. This Smart Grid Report focuses on technologies and processes that can be readily integrated in an affordable manner within the existing electrical grid infrastructure.

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 enhancements in order to form an affordable and proven foundation for existing and future smart grid projects.

A key effort at Pacific Power this past year has included the deployment of the advanced metering infrastructure consistent with the AMI roadmap defined last year. Pacific Power is on track and will proceed with deployment of AMI in the state of Oregon.

Additional key efforts for Pacific Power in the state of Oregon include:

- Developing transmission synchrophasor locations and modeling criteria consistent with MOD-033
- Central energy storage evaluation in conjunction with Oregon HB 2193 and UM 1751
- 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 Energy Imbalance Market
- Transportation electrification pilot programs in conjunction with SB 1547

The Company's investments in grid modernization and smart grid technologies is divided into various sections within the Report. The Company has completed, is monitoring, or is developing grid enhancement initiatives that include:

- **Advanced Metering Infrastructure (AMI)** - network and metering infrastructure that improves customer service and provides a platform for future smart grid applications.

- **Transmission Network Enhancements -** transmission system investments that improve grid reliability and monitoring.
- **Substation Enhancement Projects -** substation investments that increase flexibility of distributed energy resource integration.
- **Distribution Automation and Reliability -** distribution automation investments in hardware and software that enable remote or automatic configuration of the distribution network.
- **Demand-Side Management -** initiatives that allow for development of direct load control, targeted energy efficiency, and time-of-use programs.
- **Distribution Network Enhancements -** distribution system investments in technologies that improve system efficiency and expand distributed energy resource programs.

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

II. Staff's Recommendations for the 2017 Smart Grid Report

In response to Pacific Power's 2016 Smart Grid Report, the Public Utility Commission of Oregon (OPUC or Commission) adopted Staff recommendations for the 2017 Smart Grid Report in Order No. 16-476. These staff recommendations are summarized in Table 1 alongside the page numbers of where the requested information may be found. A high-level summary of informal comments and Company responses is included in Appendix A.

Table 1 Summary of Order No. 16-476 Recommendations

Recommendation Description	Page(s)
1. Include a high-level table summary of all stakeholder informal comments and corresponding Company responses as an appendix in future smart grid reports.	3, Appendix A
2. The Company to provide an AMI Roadmap outlining a framework for tracking: • AMI costs and cost savings • reliability improvement and reconnection times • mitigating technology obsolescence risk • customer engagement • analysis of AMI data and data application • transition from AMI "capabilities" to "functionalities" and clearly defined milestones that would motivate this change	Throughout
3. Company to apprise the Commission of any new developments of new Dynamic Line Rating (DLR) projects.	20
4. Company to continue to apprise the Commission of the success, or lack thereof, of remedial action scheme(s) in the form of redundant relays.	20
5. Company to provide a comprehensive narrative explaining its developments, or lack thereof, both past and present, with Peak Reliability and WECC and its decision to stop its transfer of PMU data to Peak Reliability. The Company should also follow through with its commitment to address ODOE's questions.	20-21, Throughout & App. A
6. Provide an update to its irrigation load control pilot and the table on page 32 of the 2016 Smart Grid Report including Oregon data when it is available.	43
7. Company should provide a summary of its review to investigate linking distribution devices to its OMS system and energy management system.	37
8. Company to update Commission if planning on installing Field Area Network.	39
9. Company to work with Staff and interested stakeholders to schedule a demonstration no later than April 30, 2017.	39, 40
10. Company to apprise Commission of demand response developments in future smart grid projects.	42-43
11. Company should provide its Distributed Energy Resource (DER) analysis, including how Company has utilized the transmission and distribution planning tool.	44-45

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. Pacific Power's roadmap will align the relative start dates for various components in order to give an understanding of the progress required to reach a greater smart grid deployment through 2020. 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 customers' best interests.

A. Strategies

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

- Ensure that smart grid investments provide service at reasonable and fair prices by comparing products and solutions in a financial model highlighting 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.
- Leverage broad resources at the Company's disposal, including lessons learned through existing analysis and work from Berkshire Hathaway Energy, which is comprised of four separate investor-owned utilities.
- Increase customer awareness and understanding of how the electric system works and how energy usage impacts and drives Company investments and operations.

B. Objectives

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

- Provide customers with tools and understanding to change energy usage for their benefit.
- Enhance the meter data management system (MDMS) to become a scalable future smart grid data throughput platform, targeting completion by Q4 2017.
- Continually improve customer relations through customer communications and tools.
- Optimize the Company's electric system through the implementation 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. Figure 1 displays projects included in the 2017 report as well as projects included in prior-year reports. 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 concepts as depicted in Figure 2.

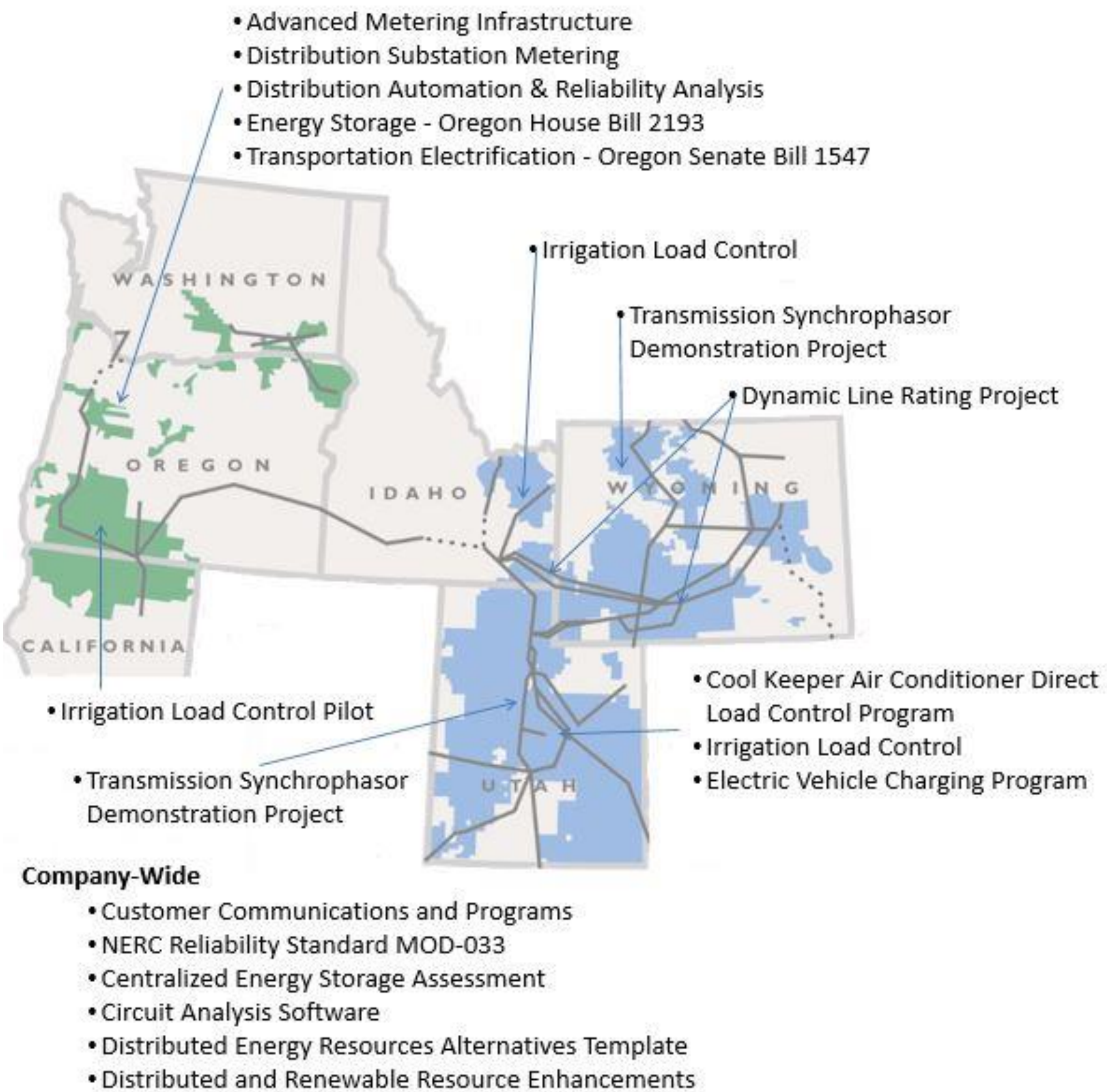

Figure 1 PacifiCorp Grid Modernization Projects

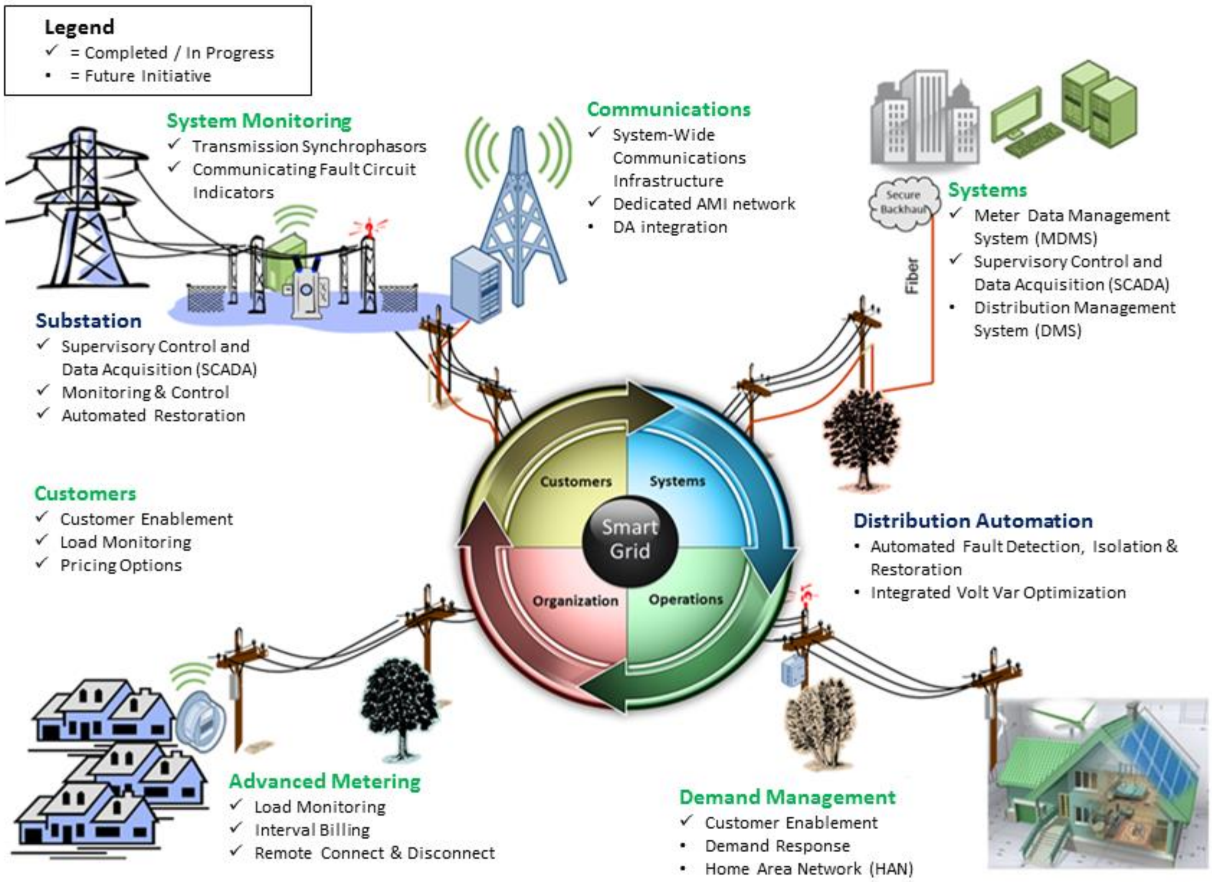

Figure 2 Select Smart Grid Concepts

Many of the smart grid technologies are dependent upon preceding technology deployment to achieve a 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. Some of the above tasks in Figure 2 will be updated completed by end of 2017.

V. Status of Grid Modernization and Smart Grid Investments

A. Advanced Metering Infrastructure and Customer Communications

1. Advanced Metering Infrastructure Background

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 operations and maintenance (O&M) labor rates resulted in a positive business case to implement AMI in Oregon.

2. Oregon AMI Roadmap

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 in an effort to begin engaging with customers.

Project Summary

The AMI program involves replacing existing customer meters with smart meters and installing a comprehensive advanced metering system. This system will include the

[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

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 costs, additional revenue through reduction of power losses and write-offs, as well as provide the following customer benefits by continuing to support 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 an energy usage website
    - Improved bill accuracy, fewer estimated bills
    - Improved response time for connection of service
    - Allows customers to manage energy usage through information access
    - 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 regularly
- 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
- Improving environmental compliance through CO_2 reductions due to fewer 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 analyze the results of their energy decisions before and after the fact, feel as though they have more control over their electric energy usage through increased knowledge, and act on those feelings to change behavior.

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

- Provide an energy usage website 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 interrogating the meter
- Collect and analyze voltage, power quality, tampering, and system data
- Remotely reprogram meters as needed

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

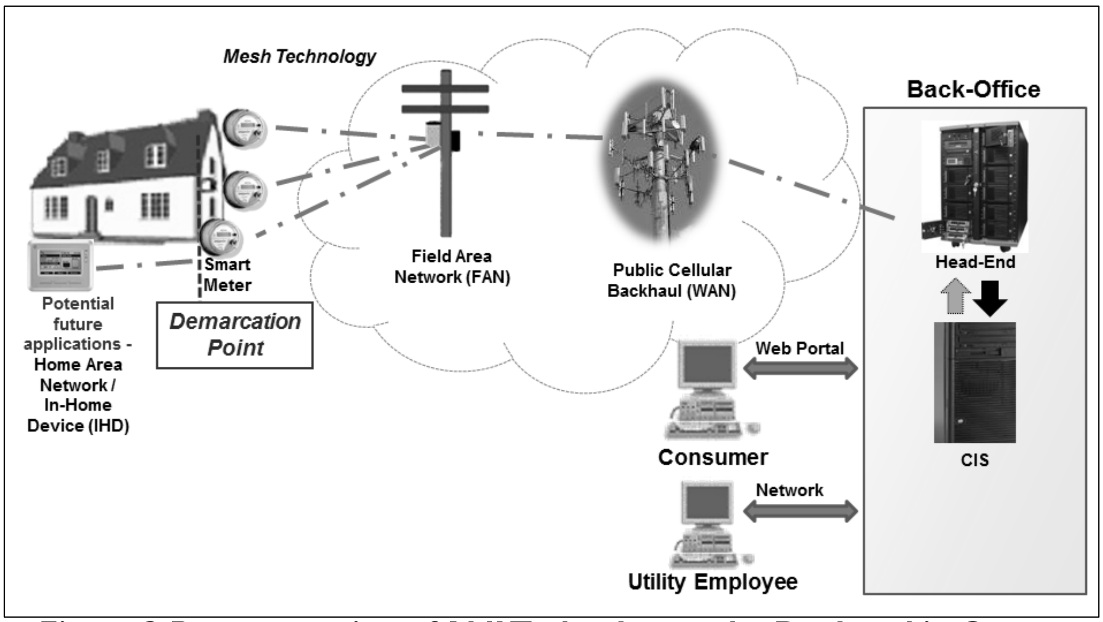

Figure 3 Representation of AMI Technology to be Deployed in Oregon

The key components in the AMI network include smart meters, the communications network, and back-office software/IT system improvements.

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 – 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. 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 local area 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 Energy Usage Website –** A web-based solution providing 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:

- Critical peak pricing or prepaid pricing capabilities.
- Limited tariff billing functionality aimed primarily at distributed energy generation.
- Integration with the Supervisory Control and Data Acquisition (SCADA) and Distribution Management System (DMS) systems.
- Functionality that provides customer data to a home area network (HAN).
- Capability to automate interactive volt/VAR optimization (IVVO).
- Various Distribution Automation (DA) capabilities.
- 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.

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

AMI Project Update

The Oregon AMI project is on schedule and will be ready for customer and industrial billing in December 2017 using AMI technology where the Field Area Network (FAN) is installed and the meters have been upgraded. FAN design is largely complete, with construction scheduled to begin in Q2 2017. Mass meter installs will begin in January 2018 as scheduled and will conclude in August 2019. The project remains on track for completion in December 2019. There are no changes in the technology being used for the project.

Table 3 includes a status / update for key milestones with notes referencing changes (if any) to milestone dates:

Table 3 Current AMI Project Timeline

Stage	Timeline	Activity	Status / Update
IT & Network Design	Q2 2016 – Q4 2016	AMI Lab Environment, Technical Design, Communication Network Design, Customer Portal Development	Complete: AMI Lab Environment, Technical Design, Communication Network Design Q1 2017 – Q2 2017: 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.	On Schedule
Training	Q3 2017 – Q1 2018	System training for support, Field, and Call Center employees	On Schedule: Call Center and support employees Q3 2017 – Q3 2019: Field employees
Meter Installation	Q1 2018 – Q4 2019	Conduct meter exchange deployment across Oregon service territory	Q1 2018 – Q2 2019: Meter exchange deployment
Project Close	Q4 2019	Project evaluation and final documentation	On Schedule

3. AMI Strategy

Construction standards have been developed for the AMI network hardware that will be installed on transmission and distribution poles. While external hardware integration remains a key focus, it is too early to start modifying standard equipment to integrate with an evolving AMI network topology. As a result, no external hardware standards or specifications have been modified to directly integrate with the AMI network at this time.

4. AMI Functionalities

The new AMI meters, the i210+c and the kV2C, both are capable of eight channels of data. The i210 is the 240 V, single-phase meter scheduled to transmit data with a resolution of one hour. The kV2C meter is the 480 V, three-phase meter scheduled to transmit data with a resolution of 15 minutes. The cellular data backhaul will be conducted every four hours.

As part of the AMI implementation, the Company will deploy a field area network and cellular communications to interface with smart meters. Depending on the location of electrical vehicle charging pods and the type of equipment and network used, there may be an opportunity to integrate charging pods directly into the AMI communications network. This opportunity will be further assessed through the request for proposals process for charging equipment and services for the Public Charging Pilot.

5. AMI Costs and Savings

The Work Breakdown Structure (WBS), as shown in Figure 4, for the OR AMI project has been established to track charges by location and type of asset. The WBS establishes the appropriate structure, work orders, and associated settlement rules. Additional WBS elements and work orders are created as needed to track costs for separate work efforts and to allow assets to be put into service appropriately.

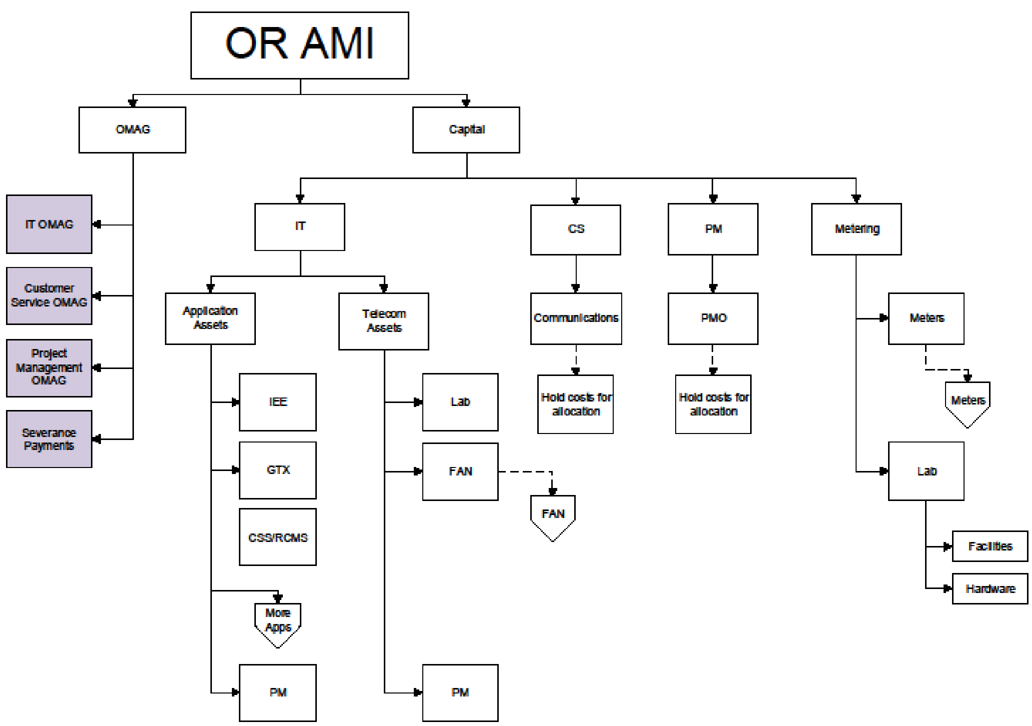

Figure 4 Tracking of AMI Costs

Framework for tracking savings

Table 4 describes AMI business case savings with a description of how each item will be tracked and the status on development of the tracking mechanism.

Table 4 Tracking of AMI Savings

Description	Business Case Savings	Method	Status
Reduce the following operational costs: Meter Reading Collections Meter Managers Metermen Clerks	Savings will be realized through the automation of job functions and replacement of the majority of meters in Oregon.	Establish a baseline of employees who are on the payroll at the start of the project. Employee reductions will be reported against departures tied to the AMI deployment schedule.	Spreadsheet complete and being utilized to track staffing changes.
Reduce Overtime (Metering and T&D)	The ability to remotely connect service will eliminate the need to physically visit most meters after working hours to connect service.	SAP Mobility Workforce Management System After hours connect trip (RPM) volumes will be tracked as well as overtime hours. The numbers will be measured against pre-AMI costs.	Overtime expense is tracked today in the payroll system. Reconnect request volumes are tracked today in our Mobility system.
Avoided Handheld Maintenance and Repair	Meter reading handheld maintenance expense will decline as the number of handhelds decline.	Handheld maintenance expense is tracked in SAP. Post-AMI expense will be compared to pre-AMI expense.	SAP expense tracking in place. Comparison requires development.

Description	Business Case Savings	Method	Status
Reduced suspend resolution cost	Access to interval meter reads will streamline the suspend resolution process.	Compare pre-AMI suspend resolution labor to post-AMI suspend labor.	Requires development.
Theft Reduction	Visiting each meter during the exchange process will enable the business to detect theft and stop it.	Establish a business process for the mass meter installer to alert utility of theft cases. Analysis will be performed to quantify value of loss.	Requires development.
Reduced Power Losses	The ability to disconnect service between tenants will reduce the amount of power loss.	Compare unbilled kWh between tenants post meter exchange to baseline data in the business case.	In place.
Revenue from Added Meters with VARs	Establish VAR billing for all applicable customers.	Establish baseline data by extracting VAR billing data prior to meter exchanges. Compare post meter exchange values to determine incremental benefit.	Requires development.
System Energy Loss Reductions	Mechanical meters require 24 watts of energy before they start and electronic meters require only 5 watts. Mechanical meters consume .70 watts of	Perform lab testing to validate electronic meter performance in conjunction with industry and company findings.	Requires development.

Description	Business Case Savings	Method	Status
	energy to operate compared to .46 watts for an electronic meter.		
Revenue Recovery on Unaccounted for Energy	Electronic meters are more accurate than mechanical meters.	Perform lab testing to validate electronic meter performance in conjunction with industry and company findings.	Requires development.
Reduction in Write-offs	Write-off expense will decline with the ability to perform collection disconnects sooner.	Write-offs are currently tracked as a percent of revenue. Collection order volumes are tracked in the Mobility Workforce Management System. Baseline data will compare the time to disconnect pre-AMI to post-AMI. Compare pre-AMI write off expense to post AMI write off expense.	Write-off expense and collection volumes are currently tracked. Baseline time to disconnect data requires development.
Avoided Meter Purchases	Replacing the majority of meters in Oregon will reduce meter failure rates thereby reducing the need to purchase replacement meters.	Meter purchase expense and volumes are tracked in SAP. Compare post- AMI purchase expense and volumes to pre-AMI purchase expense and volumes.	Meter purchase expense and volumes are currently tracked. Comparison requires development.

Description	Business Case Savings	Method	Status
Avoided Load Study Costs	Interval/register data provided via AMI eliminates the need to install unique meters/programs for load study purposes.	Historical data will be compared to post AMI data and quantified.	Historical data available. Comparison requires development.
Avoided Handheld Replacement Costs	Handheld replacement costs will decline as the number of employees decline.	Handheld replacement costs are tracked in SAP. Post-AMI replacement costs will be compared to pre-AMI costs.	Replacement costs are currently tracked in SAP. Comparison requires development.

6. Reconnection times

After review of product capabilities and discussions with peer utilities, the Company can commit to reconnect service within 60 minutes of sending a message to the meter to reconnect service. The following items trigger the message:

- Contact from customer with satisfactory payment arrangements.
- Receipt and recording of payment.

The Company will establish a mechanism for tracking actual reconnect times before beginning disconnection of customers remotely. This work will be done in the next 12 months. The Company envisions the potential to extract actual reconnect times and comparing them to order issue times on a monthly basis in order to ensure that the Company is meeting the 60 minute commitment. A back-up process will be established to monitor reconnection failures and dispatch crews when needed.

7. Mitigating Technology Obsolescence Risk

Regarding technology obsolescence risk, the Company reiterates that the AMI meters have a 25-year useful life, but also notes that technologies can become unsupportable five to ten years after commissioning. To mitigate these risks, the Company is adopting the following strategies:

- Vendors provide support commitments.
- PacifiCorp uses an open protocol network.
- PacifiCorp provides an AMI roadmap that includes hardware and software updates.

PacifiCorp AMI hardware and software roadmap by component:

- Annual regulatory meter test program ensures meter assets are operating correctly.
- Field Area Network access points (AP) and relays are monitored 24 x 7 for failure and replaced as needed.
- AP batteries are on a five year replacement cycle.
- AMI head-end servers are on a five year replacement cycle.
- AMI head-end applications are upgraded by the vendor.
- Meter Data Management applications are maintained by license agreement.
- TIBCO applications are maintained by license agreement.
- Open System servers are patched two times a year.
- Windows servers are patched 12 times a year.
- Oracle databases are patched four times a year.
- Mainframe servers are replaced on a five to ten year cycle.
- Mainframe OS and other supporting software are maintained by license agreement.
- Mainframe OS and other supporting software are upgraded as required per application hosted on the mainframe.

B. Transmission Network and Operations Enhancements

1. Dynamic Line Rating (DLR) and Remedial Action Scheme Update

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. DLR systems allow utilities to utilize this available thermal capacity.

Future Action and Timeline

PacifiCorp currently has two DLR installations in its eastern service territory, but no installations in Oregon. No specific timeline for future DLR installations is available as installations are being evaluated on a case-by-case basis.

Remedial Action Scheme update

A Remedial Action Scheme installed on the Grace-Soda 138 kV line in 2016 as an alternative to a combination of a thermal replicating relay and dynamic line rating solution is in-service and functioning as designed with no future action anticipated.

2. Transmission Synchrophasor Demonstration Project

Transmission synchrophasors, also called phasor measurement units (PMUs), may lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement. The PMU may also be used to increase reliability by synchrophasor-assisted protection for real-time measurement of multiple remote points on the grid at up to 60 samples per second. At this time however the PMUs have not been shown to substantially increase situational awareness or grid operator action. The potential benefits of synchrophasor installation and intelligent monitoring of the transmission system should focus on acting as inputs for Special Protection or Remedial Action Schemes (RAS).

Project Summary

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

Project Description and Analysis

PacifiCorp participated in the WECC Western Interconnection Synchrophasor Project.[4] The project supported WECC and Peak Reliability in maintaining 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 and other participating utilities take part in monthly synchrophasor performance and data quality meetings hosted by Peak Reliability to ensure the data integrity. 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.

Future Actions and Timeline

At this time, PacifiCorp System Operations is not utilizing synchrophasor data in its real-time operations. PacifiCorp has robust Energy Management and Supervisory Control and Data Acquisition Systems (EMS/SCADA) including 179,000 status points and 116,000 analog points which provide system operators with real-time system data every two seconds for maintaining situational awareness.

PacifiCorp deployed eight PMUs at eight substations. PacifiCorp has over 300 transmission substations so this program represented a very small sample size of the PacifiCorp transmission system. This data was collected at a central PacifiCorp office and was then provided to the Peak Reliability Coordinator with the understanding that it would be used to develop and demonstrate tools for improving operator situational awareness that were measurable and meaningful. However, after several years in this program, the tools and limited data from only a handful of substations in the Western Interconnection have yet to produce timely situational awareness information that could be used to make real-time decisions for PacifiCorp Transmission operations. In the summer of 2016 PacifiCorp

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[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

[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

stopped transferring data from PacifiCorp to the Peak RC because of the lack of useful tools and information that could be used for real-time situational awareness and the ongoing cost to maintain the transfer to Peak RC; in the future PacifiCorp may restart the stream depending on tools available. PacifiCorp continues to collect PMU data at its central PacifiCorp office that can be used to analyze past system events and also support modeling and transmission planning. As part of the National Electricity Reliability Corporation (NERC) standard MOD-033-1 discussed below, PacifiCorp will be expanding PMU coverage throughout its system for assisting in this analysis of past events and model validation.

PacifiCorp's experience interfacing with Peak Reliability spotlighted the importance of data management and asset management policies. Monthly meetings were held with Peak Reliability to address data quality issues as opposed to how the PMU data could be utilized. The interface between field PMU's, communication networks, IT firewalls, and PMU hardware failures created a maintenance intensive project to ensure Peak Reliability could receive accurate data; the biggest lesson learned about working with PMU's was that quality data is difficult and costly to maintain. The technology needs to become more hardened and reliable before it can be used for real-time system operation. PacifiCorp is very interested in seeing the direction the industry moves toward with regard to tools and applications that can effectively utilize the high-speed data provided by PMUs and their impact on real-time system operations.

3. NERC Reliability Standard MOD-033-1

National Electricity Reliability Corporation (NERC) standard MOD-033-1, *Steady-State and Dynamic System Model Validation*, establishes consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system. NERC MOD-033-1 has a standard effective date of May 1, 2017.

Project Summary

To meet compliance with the new NERC MOD-033-1 standard, PacifiCorp has planned to install within the next year, Phasor Measurement Units (PMUs) at key transmission and generation facilities throughout the six state service territory. PMUs provide sub-second data for voltage and current phasors, which can be used for event analysis and model verification.

In Oregon, PacifiCorp is targeting PMU installations at key substations in the Portland, Bend, Klamath Falls, Medford and Roseburg areas. Locations determined throughout the Company's service territory are based on criteria outlined in standard PRC-002, with additional locations added as needed to give visibility to operating areas not covered by PRC-002 criteria. The planned list of new installations is provided in Appendix D.

Additionally, large wind, hydro and natural gas generating facilities in Oregon will have PMUs installed. Data will be streamed to a central storage server where offline analysis can be performed by transmission planners and protection engineers.

Transmission planners will use the phasor data quantities from actual system events to benchmark performance of steady-state and transient stability models of the interconnected transmission system and generating facilities. Using a combination of phasor data from the PMUs and analog quantities currently available through SCADA, transmission planners can setup the system models to accurately depict the transmission system prior to, during and following an event. Differences in simulated versus actual system performance can then be evaluated to allow for enhancements and corrections to the system model.

Future Action and Timeline

Project scoping and cost estimating is underway. Design and construction is planned for completion in 2018. NERC MOD-033-1 requires Transmission Planners to perform a validation of a system model using the PMU data by July 1, 2019.

Model validation procedures are 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. While likely locations for PMU installations have been identified, equipment and communication needs have not been scoped and therefore a cost estimate is not available at this time. The scope and estimate are estimated to be fully complete in July 2017.

4. Energy Imbalance Market

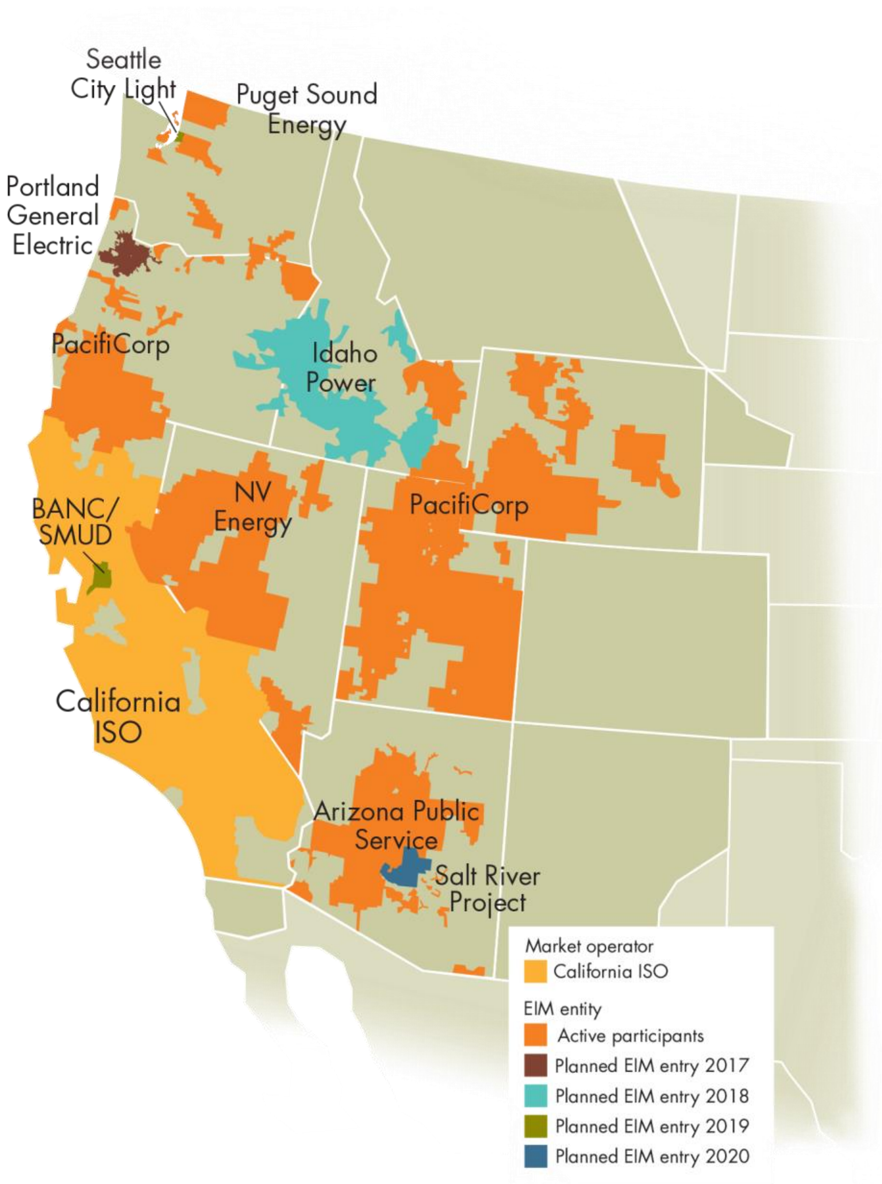

Figure 5 EIM Market Participant Map

PacifiCorp and the California Independent System Operator ("ISO") launched the Energy Imbalance Market (EIM) November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California, covering eight states, California, Nevada, Arizona, Idaho, Oregon, Utah, Washington, and Wyoming, which uses California ISO advanced market systems to dispatch the least-cost resources every five minutes. Since the launch of the EIM, Nevada Energy joined the market December 1, 2015, Puget Sound Energy and Arizona Public Service joined October 1, 2016 and Portland General Electric and Idaho Power Company are expected to join the EIM October 1, 2017, and April 1, 2018 respectively. Seattle City Light and Balancing Authority of Northern California and its member Sacramento Municipal Utility District are both expected to join the EIM April 1, 2019, and Salt River Project is scheduled to join the EIM April 1, 2020. PacifiCorp continues to work with the California ISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

The EIM has produced significant monetary benefits ($142.62 million total footprint-wide revenues or avoided expense as of December 31, 2016), quantified in the following categories:

- more efficient dispatch, both inter- and intra-regional, by automating dispatch within and across the EIM footprint;
- reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and
- reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

A significant contributor to EIM benefits are transfers across balancing areas, providing access to lower cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the ISO to serve California load. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the 5 and 15 minute market dispatch intervals.

5. Cybersecurity

Potential cyber security threats to the utility industry range from a cheating customer to a foreign nation-state attack. In particular, Smart Grids may be vulnerable to three primary threats: customer attacks, insider attacks, and terrorist or nation-state attacks. To defend against these vulnerabilities, PacifiCorp's Smart Grid program is implementing a comprehensive, layered approach to cybersecurity.

Project Description

PacifiCorp is pursuing a multi-tier approach to Smart Grid security, including compliance with National Institute of Standards and Technology (NIST) security guidance, audits, penetration tests, technical controls, and security monitoring. NIST publishes a comprehensive set of security controls (NISTIR 7628) for Smart Grid systems. PacifiCorp and its Smart Grid vendor have aligned with these security controls.

PacifiCorp has engaged a third-party security firm to audit both PacifiCorp and its Smart Grid vendor against the NIST Smart Grid Security Controls during the scope of the Oregon Smart Grid project. In addition, the Smart Grid vendor must undergo an annual service organization controls (SOC2) audit covering the scope of services under the contract and provide the results to PacifiCorp. The Smart Grid system will be subjected to penetration testing to ensure the audited controls are performing as expected and any discovered issues will be addressed.

PacifiCorp's information security team is actively involved in the system design process to ensure that appropriate technical controls are in place. Controls include:

- KeySafe and critical operations protector hardware devices that protect meter encryption and provide a fail-safe against large-scale disconnect operations.
- Multi-factor authentication.
- Network segmentation to prevent unauthorized access to Smart Grid systems.
- Web application firewalls to inspect web traffic for potential attacks.

The Smart Grid vendor operates a 24x7 security operations center that will be responsible for monitoring the meters, access points, and vendor-provided systems. Its security infrastructure includes comprehensive log monitoring, threat prevention and detection systems, malware detection, network traffic capture and anomaly detection, and vulnerability management. In addition, PacifiCorp will monitor Pacific Power-operated systems for security events.

C. Substation Operations Enhancements

Substation and distribution projects include centralized energy storage, communicating faulted circuit indicators, distribution automation, operational management systems, 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 and has high opportunity costs when generation is decreased unexpectedly. 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

On June 15, 2015, the Oregon legislature passed House Bill (HB) 2193. The primary purpose of HB 2193 is to encourage the development of energy storage projects in the state of Oregon. The Company as a regulated electric utility serving in the state of Oregon, is required under HB 2193[7] to submit one or more energy storage project proposals to the Public Utility Commission of Oregon (Commission) by January 1, 2018. If authorized by the Commission the Company is required to procure one or more qualifying energy storage systems with the capacity to store at least five (5) megawatt hours (MWh) of energy by January 1, 2020, with the total power capacity of the qualifying system(s) procured to be no more than one percent of the electric utility's peak load. Furthermore, HB 2193 obligates the Company to implement energy storage even if it is not cost effective. The Company must submit a draft energy storage potential evaluation (Assessment) by July 15, 2017 evaluating the benefits and costs of energy storage to the Company's systems. In response to HB 2193, Commission docket UM-1751 was created. On January 4, 2017, the Commission issued their "Guidelines and Requirements Adopted to Implement HB 2193[8] (Guidelines) , which includes language strongly encouraging electric utilities to release a request for information (RFI) identifying viable technologies and qualified vendors and to submit the RFI results with the draft Assessment on July 15, 2017.

As outlined in the 2016 Annual Report, 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 5D22 circuit will continue to be evaluated as a potential candidate for energy storage and may satisfy the guidelines of HB 2193.

Energy Storage Evaluation Project Summary

In February 2017, Pacific Power released a request for proposal (RFP) with the intent to hire a consultant to perform the energy storage potential evaluation in Pacific Power's Oregon service territory with proposed strategies and methodologies that materially complies with the Guidelines. In April 2017, DNV GL was awarded the contract to conduct this evaluation.

Project Description and Analysis

The Company will leverage existing information and data on energy storage. DNV GL has reviewed the Company's previous work performed on energy storage through PacifiCorp's Integrated Resource Plan (IRP) and supporting studies; specifically the Battery Energy

[7] House Bill 2193 can be found at: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193
[8] UM-1751 can be found at: http://apps.puc.state.or.us/orders/2017ords/17-001.pdf

Storage Study for the 2017 IRP. DNV GL has provided the requested scope and will present initial findings on August 3rd, 2017 to the OPUC.

The statement of work includes the following:

1. Identify energy storage potential by use case or application with the ability to be implemented by year end 2026. A key objective is to provide recommendations for storage projects and their proposed use that can be installed by 2020.
2. Identify higher- and lower-value applications for energy storage.
3. Develop criteria for designating higher- and lower-value applications and explain how the criteria are applied.
4. Identify locations within the Company's service territory in the state of Oregon with the greatest energy storage potential, including applications such as customer-side (e.g. residential, commercial, industrial) and/or utility-side (e.g. distribution and transmission).
5. Develop a recommended methodology for determining energy storage potential, including:
    a. How the methodology should be applied, and
    b. Identify critical limiting factors that affect estimates of storage potential by application.
6. Provide all material inputs, assumptions and other calculations needed to designate higher- and lower-value applications.
7. Estimate potential costs and associated cost effectiveness of the addition of energy storage to the Company's system.
8. Provide an assessment of potential qualitative and quantitative benefit to the electric system and customer of energy storage.
9. Project trends in energy storage system cost and performance.
10. Recommend an established model to estimate the value of energy storage applications such as the Pacific Northwest National Laboratory's "Battery Storage Evaluation Tool" or the Electric Power Research Institute's "Energy Storage Valuation Tool".
11. Other items as listed within the Commission's Initial Storage Workshop Scope of Work.
12. Consultant will be expected to provide a presentation of their initial findings and respond to questions at a public meeting with the Public Utility Commission of Oregon on August 3rd , 2017.

2. Energy Storage Assessment

The U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) in collaboration with National Rural Electric Cooperative Association (NRECA) developed the Electricity Storage Handbook[9] (referred to in this report as the "DOE Handbook") (Sandia Report SAND2015-1002). The DOE Handbook provides an industry standard for energy storage terminology, which PacifiCorp currently uses. Although the DOE Handbook does not use the terms "centralized" or "distributed" to categorize energy

[9] The DOE Handbook can be found at http://prod.sandia.gov/techlib/access-control.cgi/2015/151002.pdf.

storage, PacifiCorp has developed the following definitions based on the Electricity Storage Handbook.

Centralized Energy Storage refers to energy storage systems capable of providing "Bulk Energy Services" as defined in Section 1.1 of the DOE Handbook. Figure 19 in Chapter 2 of the DOE Handbook shows Pumped Hydro and Compressed Air Energy Storage (CAES) as two mature technologies capable of providing bulk energy services. Pumped hydro and CAES may also be able to provide other electricity storage services and benefits listed in Chapter 1 of the DOE Handbook. These technologies were studied as part of the IRP Bulk Energy Storage Study described in the next section.

Distributed Energy Storage refers to energy storage systems not capable of providing "Bulk Energy Services" as defined in Section 1.1 of the DOE Handbook. Figure 19 in Chapter 2 of the DOE Handbook shows a variety of technologies that target the electricity storage services and benefits other than bulk energy services. The IRP Battery Energy Storage Study describes these technologies in the next section.

Energy storage evaluation

PacifiCorp conducted two energy storage studies for its 2017 Integrated Resource Plan (IRP)[10]: Battery Energy Storage Study and the Bulk Storage Study were performed. The purpose of these studies was to update studies performed for previous IRPs. The Battery Energy Storage Study focuses only on battery technologies, whereas The Bulk Energy Storage Study focuses on pumped hydro and CAES. The estimates and information in the studies was used to inform the 2017 IRP and may be used to develop alternative applications to traditional utility transmission and distribution approaches. The Bulk Energy Storage Study addresses centralized energy storage while the Battery Energy Storage Study addresses distributed energy storage as defined above. More in-depth information regarding these studies are below.

Battery Energy Storage Study

The Battery Energy Storage Study[11] was conducted by DNV GL (also known as KEMA, Inc.). The study updated the following: 1) engineering estimates for the cost and performance of utility scale battery energy storage technologies, 2) a current catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates of performance and costs, and 3) a probabilistic cost forecast for each of the

[10] Supporting studies for PacifiCorp's IRP can be found at http://www.pacificorp.com/es/irp/irpsupport.html.
[11] The Battery Energy Storage Study can be found at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf.

technologies; broken out by technology costs, energy conversion system costs and O&M costs.

The battery technologies identified for updates include the technologies identified below. A couple of changes were made relative to the technologies studied in previous IRPs. Lithium ion batteries were split into the three most common sub-chemistries and two emerging zinc technologies were added to the list.

Commercially Available Technologies:

- Lithium ion batteries (Li-Ion)
    - Lithium Nickel Manganese Cobalt Oxide ($LiNiMnCoO_2$ or NCM)
    - Lithium Iron Phosphate ($LiFePO_4$)
    - Lithium Titanate ($Li_4Ti_5O_{12}$ or LTO)
- Sodium sulfur batteries (NaS)
- Flow batteries: Vanadium Redox (VRB)

Emerging technologies:

- Zinc Bromine (ZnBr) Redox
- Zinc Hybrid Cathode (Zinc-air)

For each technology the following technological information will be updated:

- Stage of Commercial Development
- Typical project size (kW & kWh)
- Largest project size installed (kW & kWh)
- Current total power capacity (MW) installed
- Current total energy storage capacity (MWh) installed
- Performance Characteristics
- Power Capacity
- Energy Capacity
- Recharge Rates
- Roundtrip Efficiency
- Availability
- Degradation
- Expected Life
- Environmental Impact upon disposal

In addition to updating the technological assumptions, the study updated the cost estimates and developed cost trend forecasts for the next ten (10) years. Capital cost forecasts were broken out by storage equipment, power conversion system equipment, power control system and balance of system. No forecast was provided for fixed operation and maintenance (O&M) costs, which presents some challenge in estimating costs because there are a wide variety of O&M agreements and capacity maintenance agreements which are sometimes rolled into upfront capital costs or combined as a single O&M agreement.

There is not currently a uniform or industry acceptable methodology for quantifying variable O&M.

Utility Applications and Value Stream is a new subject covered in this study. The applicability of each technology and the relative potential for generating economic value were studied for the following benefit cases within the Company's service territory over the next 20 years. Potential uses include:

- Electric Energy Time Shift
- Electric Supply Capacity
- Regulation
- Spinning, Non-Spinning, and Supplemental Reserves
- Voltage Support
- Load Following/Ramping Support for Renewables
- Frequency Response
- Transmission and Distribution Congestion Relief

Bulk Energy Storage Study

The Bulk Energy Storage Study[12] provides an update to engineering estimates for the cost and performance of utility scale bulk energy storage technologies.

The bulk energy storage technologies identified for updates include the technologies identified below. PacifiCorp has no affiliation or partnership with any of these projects. They are considered to be in a medium stage of development and are representative of what is available to PacifiCorp for these types of energy storage systems. The study provides an updated project status, description, schedule and various levels of detail.

Pumped Hydro (PH)

- Swan Lake North
- JD Pool
- Seminoe (previously Black Canyon)

Compressed Air Energy Storage (CAES)

- Western Energy Hub
- Norton Energy Storage
- PG&E Kern County CAES
- Adele CAES
- APEX Bethel Energy Center

[12] The Bulk Energy Storage can be found at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf.

Case-by-Case Analysis of Energy Storage Solutions

In 2015, PacifiCorp hired Black and Veatch (B&V) to develop a cost estimating model for battery energy storage systems (BESSs). The model was vetted against information in the DOE Energy Storage Database and will be updated using the information provided in this year's battery energy storage study. Estimating the value cases of BESSs is still under development. PNNL recently developed the Battery Storage Evaluation Tool (BSET) which models up to four stacked use cases using actual load data. PacifiCorp is also participating in EPRI's Energy Storage Integration Council (ESIC) on the development of a new model called StorageVET. It appears to combine aspects of previous models and recently underwent alpha and beta testing.

While these models are being evaluated, more work is needed to accurately model the value of potential energy storage projects. Projects must be evaluated on a case-by-case basis with the model inputs scrutinized for the individual project's circumstances. Additionally, in a dynamic market those values may change over time, especially as more of the services are introduced to the market. The Company will continue to work with organizations like ESIC to further develop storage valuation modeling.

3. 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 limited visibility on loading levels as well as provide information on load shapes and power quality.

Project Summary, Description, and Analysis

Pacific Power plans to deploy advanced substation meters at distribution substations that have limited or no 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.

Future Actions

Pacific Power is in the process of selecting an advanced substation meter based on the requirements listed in Appendix F – Distribution Substation Metering Technical Requirements and is in the process of evaluating locations for the pilot program. It is anticipated the advanced meters will be installed, and the data management system will be gathering data by Q1 2018.

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

D. Distribution Automation and Reliability

Distribution automation (DA) is an all-inclusive term that includes fault detection, isolation, and restoration (FDIR), communicating faulted circuit indicators (CFCIs), and indication and/or control of distribution devices such as reclosers, FuseSavers, regulators, and capacitor banks. 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 can either communicate their status to a centralized 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, or they can communicate amongst themselves and using field level intelligence, determine the optimal switching strategy to restore customers. In the latter case, although device controllers determine the switching as opposed to a central DMS, devices still communicate status to and can be controlled by centrally located Company system operators.

CFCIs are used to assist in field locating the faulted component of the system and help reduce the time needed for restoration.

Pacific Power evaluates cost effectiveness for each areas where reliability performance is not meeting local expectations. As these areas are evaluated, a determination is made whether local improvements should incorporate elements which might be useful as an element to pilot work that is consistent with Smart Grid or Grid Modernization goals. Over the last four years, certain areas have been determined valuable as elements within such a platform.

Commission and Pacific Power track reliability using certain standard metrics in the determination of the effectiveness and efficiency in the operation, maintenance, and repair of the distribution system. One thing that Pacific Power would like to caution on is the unforeseen consequences caused by incorporation of Smart Grid assets into Pacific Power's DMS on these metrics. While Pacific Power believes that reliability and security will improve to customers, the potential changes to how reliability is measured are unknown.

1. Distribution Automation Feasibility Study

As discussed in the 2016 Report, a new study of Pacific Power's distribution system was initiated to assess where distribution automation may have an improved cost benefit over the holistic system approach analyzed in prior smart grid reports.

The key criteria and requirements for selection of potential DA locations were determined, and were 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.

Based on the above criteria developed to achieve the improvement, 40 distribution circuits in Oregon were selected on which further study would be performed.

Project Update and Analysis

A reliability analysis was performed on each of the selected 35 circuits to quantify the reduction in customer minutes lost given the application of a FDIR scheme on each circuit. Assuming a similar performance to the past three years of reliability, the analysis projected the incremental reduction in customer minutes lost if a FDIR scheme were introduced. The incremental improvement takes into consideration that the FLISR scheme is only effective on main line outages, and also assumes a recloser has been previously installed in the main line and its reliability improvement already obtained. Thus, the reductions provided in the analysis are isolated to the improvements gained by the distribution automation FLISR scheme only.

For each circuit, the past three years of reliability data was attained as a baseline. The following assumptions were applied to the analysis:

- Each circuit's reliability performance will continue as identified in the baseline.
- The recloser or switching device is sited such that 50 percent of customers are located on either side of the recloser.
- A standard recloser installation will reduce customer minutes lost by 25 percent.
- Additional reductions from manual switching were calculated using Oregon's average crew time to arrival of 87 minutes plus 60 minutes for switching.

Table 5 summarizes the reduction in customer minutes lost and the percent improvement on the overall customer minutes lost for each of the 35 circuits. Note that an improvement of zero percent in the analysis relates to the fact that over the past three years, no main line outages have occurred on its respective circuit.

Table 5 DA Feasibility Study Improvements

Operating Area	Substation Name	Feeder Name	CML Reduction	Percent Improvement
Grants Pass	Agness	Jones Creek	44644	4
Grants Pass	Caveman	Quail	14519	2
Grants Pass	Caveman	Washington	0	0
Grants Pass	Caveman	Manzanita	0	0
Grants Pass	Caveman	Caveman	43725	5
Grants Pass	Park Street	Express	0	0
Grants Pass	Park Street	Portola	147042	14
Hood River	Hood River	Residential	934	0.3
Hood River	Hood River	North	59591	11
Lincoln City	Devil's Lake	Ocean	58129	5
Lincoln City	Devil's Lake	Lake	713695	9
Lincoln City	Devil's Lake	Siuslaw	40831	4
Medford	Belknap	Barnett	71368	15
Medford	Brookhurst	Crater Lake	0	0
Medford	Brookhurst	Sunrise	32728	8
Medford	Foothills	Hospital	0	0
Medford	Foothills	Pierce Road	41859	14
Medford	White City	Avenue C	0	0
Madras	Cherry Lane	Seven Peaks	2546	23
Portland	Alderwood	2	11572	6
Portland	Columbia	1	11266	5
Portland	Cully	3	16795	2
Portland	Cully	1	0	0
Portland	Holladay	5	0	0
Portland	Holladay	6	7667	11
Portland	Killingsworth	5	25220	13
Portland	Killingsworth	4	225778	7
Portland	Russellville	4	211766	7
Portland	Russellville	2	60185	6

Portland	Vernon	1	255557	12
Roseburg	Cloake	RUSA	13	11
Roseburg	Garden Valley	Edenbower	19730	17
Roseburg	Roseburg	Diamond	72803	6
Roseburg	Winchester	Wilber	39892	6
Stayton	Lyons	Mehama	170679	4

In addition to the reliability work done on the 35 circuits, the Company has begun to analyze the integration of distribution automation and the AMI network. Figure 6 below shows a typical integration of a recloser control into the AMI network. As can be seen from the diagram, much of the distribution automation communication equipment is exclusive to the distribution automation system itself, with the exception of an AMI relay. The AMI relay can be leveraged to convey distribution automation data traffic, as well as AMI meter traffic.

Also under evaluation is the scope of the distribution automation device data, as well as the manner in which that data is relayed back to Company backend systems. As can be observed in Figure 6, there are two data paths to Company backend systems. One is through the SSN network, access points, data management system, and eventually existing energy/outage management systems. The other is through the SSN network to Company substations where it will interface with existing SCADA system and tie directly to energy/outage management systems. The Company plans to evaluate which communication method is the best fit for the system based on cost, cybersecurity, and scope of the distribution automation effort.

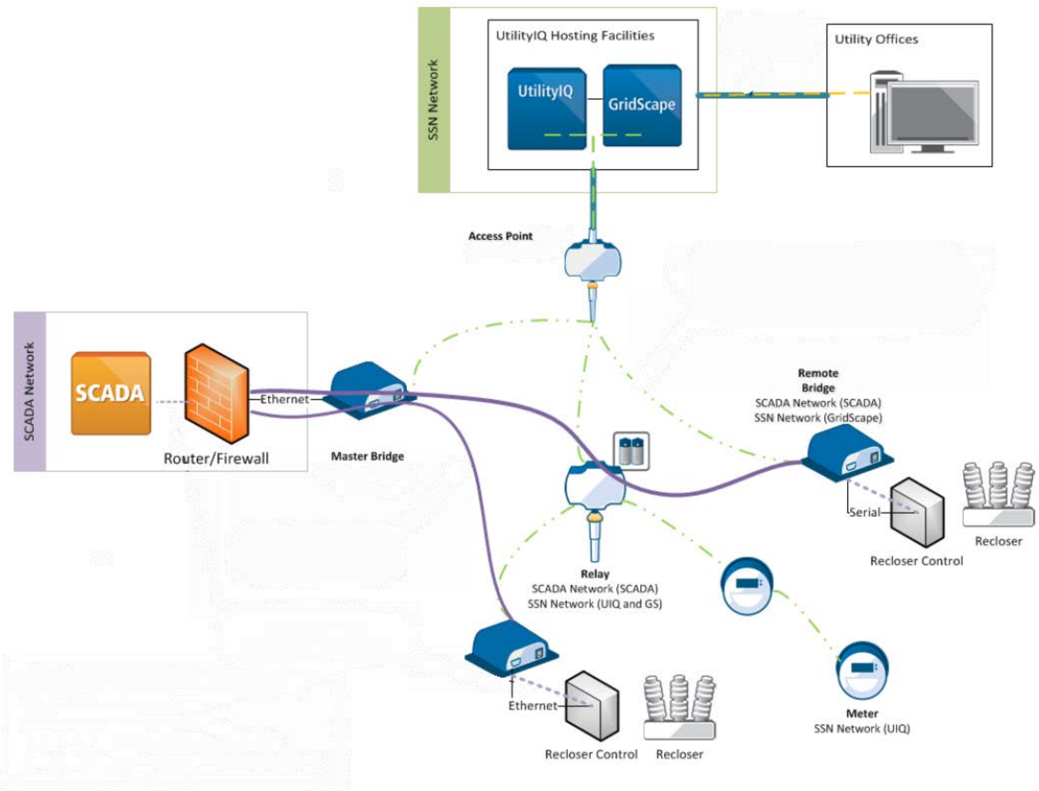

Figure 6 Example DA Communication System Leveraging AMI for Recloser Control

Future Actions and Timeline

The remaining steps identified to perform the study are ongoing. While some of the benefit analysis has been completed, the scope and cost development is still under evaluation. Once determined, verification of the cost and benefit through a pilot project may be deemed appropriate prior to widespread implementation efforts.

2. Communicating Faulted Circuit Indicators

The SCADA Monarch system was commissioned at PacifiCorp in April of 2016. The energy management system enabled the integration of CFCI data to a centralized location, where a quantifiable reliability analysis could be performed. Upon further review of CFCI requirements, integrating with the Company's new SCADA Monarch system is not the preferred solution. The majority of CFCI device locations are on distribution lines, which are not visible in SCADA Monarch Energy Management System (EMS). Preferably, CFCI devices located on distribution lines should be visible to the Company's Distribution Management System (DMS), which is the desired system for Dispatch Operations to view and make decisions on CFCI data.

Future Actions and Timeline

Beginning in fall of 2018, PacifiCorp's Distribution Management System will be upgraded to a newer version, which includes desired technology to integrate CFCI devices. Planning for this upgrade is scheduled to start this September with build out of test systems scheduled for early 2018.

As an example of DA functionality included in current scoping processes, Fuse Saving devices are currently being deployed 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 6.

Table 6 Fuse Saving Device Locations by District (in Oregon)

State	Operating Area	Installation Year	Locations	Total Devices
OR	Bend	2016	2	6
OR	Clatsop	2016	6	7
OR	Coos Bay	2016	5	8
OR	Klamath Falls	2017	5	15
OR	Klamath Falls	2016	1	3
OR	Klamath Falls	2015	1	3
OR	Total			42
Estimated benefit to SAIDI minutes for Oregon customers from fusesaver installation				0.236

While the history of effectiveness of the FuseSavers is limited, anecdotal observations indicate that they have reduced sustained interruptions by approximately 80% for the customers downstream of the device, while their rapid detection results in customers upstream (between the device and the substation) seeing a commensurate reduction in momentary interruptions. As a result, the Company calculates they have resulted in .236 minute reduction in SAIDI (approximately 0.2% improvement). The cost of each installed FuseSaver device is approximately $4,000.

PacifiCorp 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, and are being integrated with other communication-reliant pilot activities, as discussed below.

FuseSaver/Recloser/LineScope

In order to improve reliability, the Company has identified certain locations within the network where interrupting capability, such as provided by a recloser, or fault detection, such as provided by a faulted circuit indicator, would be advantageous for reliability. As the Company has evaluated these devices, many of them have the ability to be augmented with modules capable of communicating the information regarding their operations to a central system, such as a SCADA system. As such, the Company has begun exploring how to bring such functionality to fruition.

The Company has deployed FuseSaver devices and is developing communications systems protocols to incorporate such data. There are currently two pilot projects in the scoping and design process, wherein these protocols are to be developed; one for LineScope and one for CFCI/FuseSavers. The CFCI/FuseSavers pilot is reliant upon the aforementioned DMS update, while LineScope installation and piloting is planned to go live during late 2017 for a first location in the Northern Oregon Coast section of the Company system. Assuming these advanced communications pilot projects yield promising results within the next 18-24 months, equipment installation will become standard practice. Additional pilots for localized distribution automation using newly upgraded substation devices and line reclosers are being conducted at the Hillview substation in Corvallis, Oregon This project entails substation relay replacement, and line recloser installation and replacement. Fault data will be utilized by system operations personnel; certain aspects of the restoration protocols may also be conducted by the “head-end” device, specifically the proximate line recloser. Assuming project success, expected sites for expansion would be Bend, Roseburg, and Medford areas of Company territory.

3. Circuit Analysis Software (CYME)

Project Summary

The Company’s legacy load modeling software (ABB’s FeederAll) had been used by field engineering staff over the last several decades as a means to determine areas within the network which required capacity enhancement due to customer loads changing with time or with the addition of new customers to the network. This software was no longer supported, nor was it able to incorporate elements such as customer generation or other modeling requirements. In 2014 the Company began replacing this software with CYME, which is a software product that is supported by Eaton. In 2015 the Company implemented the new software within the Engineering organization. In 2016, the Company developed Gateway, which integrates Geographical Information System (GIS) and Customer Service System (CSS) data into core models from which engineers build loading cases. In 2016, system planning studies began using CYME as part of the Planning Study process.

Project Update

CYME is currently being utilized for routine planning studies, with conversion to new platform over next five years (as each load planning area is studied). Additional CYME features are being evaluated as relates to daily, monthly, or seasonal loading curves for various customer types. Further incorporation of customer generation data is also being considered.

A CYME demonstration was presented to stakeholders including the OPUC and ODOE on March 28th, 2017. The capabilities of CYME were presented alongside a discussion of the expansion of abilities we obtained by utilizing CYME. The Company and stakeholders participated in a question and answer session following the conclusion of the presentation. Staff questioned whether CYME will be able to directly use AMI data. The CYME load model cannot be updated without database edits, thus, it will not use AMI directly since those inputs are not posted to a database where Gateway can currently read them for CYME purposes. Billing could be used as input to CYME database in the future, but no process or price for this functionality has been identified or pursued at this time. With new behind the meter distributed generation, the utility would see a reduction in load, but current modeling practice has a non-negligible delay of 3 to 6 months prior to updates with new load information. AMI data may be added manually to points during studies. Smart inverter functionality is enabled in CYME, but the secondary is not modeled and this data doesn't have a source Gateway can currently read. Other inputs not currently posted where Gateway can read them include: source impedances, secondaries, customer ZIP model coefficients, SCADA and manual reads for breakers and other meter points, detailed device ratings and settings, and DER real-world output. All planning studies are being completed in CYME, and legacy FeederAll models continue to be useful as a comparison to CYME to double-check results. Staff also inquired whether we could use CYME for non-wire alternatives. CYME would work for a mesh secondary network like Portland underground network, however, an engineer would have to build a CYME mesh model of the Portland underground mesh network. The Company would also like to include breaker TCC values in CYME in the future, but that would require a non-trivial amount of engineering time of an engineer with relay, CYME, and metering experience. Present stakeholders were satisfied by this discussion.

4. <u>VaultGard Portland Low Voltage Secondary Network Project</u>

Project Summary

Install a network monitoring system on the downtown portion of the Portland underground distribution system fed from Lincoln and Albina substations. The scope of work will cover the installation of network monitoring equipment into vaults located within roughly 70 blocks of downtown Portland, bordered by SW 5th Avenue to SW 13th Avenue and from

NW Davis Street to SW Jefferson Street. Additional vaults extending towards the Albina substation may also be included in the final scope of the work.

Project Description and Analysis

Due to the mesh configuration of construction, the downtown Portland Low Voltage Secondary Network (LVSN) is a complex system to monitor and maintain. The system is composed of many aging components that include switches, transformers, cable, and network protectors. Currently, there is no SCADA or other remote means of real-time equipment monitoring to verify the operational status of the network equipment other than by bi-annual, manual vault inspections or inspections performed outages. The lack of real-time equipment monitoring data exposes the company, and our downtown customers, to major outages if equipment failures or mis-operations go unnoticed and are allowed to cascade into larger outage events. Limited ability to monitor and measure the LVSN results in uncertainty of the grid state/awareness, and limit the capability to perform planning studies of the system.

The network monitoring system will provide the following benefits:

- Improved safety for the underground crews due to a reduction in planned and unplanned confined space entries
- Improved control capability
- Ability to identify system deficiencies, such as cable overloads or overheating that is an early indicator that aging equipment may be deteriorated and ready to fail
- Detect under/overvoltages that can cause end-user equipment damage and service complaints
- Real-Time Monitoring to alert operations of any equipment abnormalities

Power-flow data will be stored in system databases to allow field/area engineers to perform network planning studies. The network monitoring system will provide the ability to monitor and report system conditions, which should help justify any reductions in the current bi-annual vault inspections. VaultGard will also provide data that can be used to produce a better awareness of secondary connectivity and the specific phasing between each network transformer and customer meter point. This improved operational knowledge can be used to improve modeling efforts, support any future LVSN reconfiguration and aid in troubleshooting anomalies.

Future Action and Timeline

An RFP is being requested by vendors to install the network monitoring system and the request for RFP is being put together at the moment. An approved bidder will be chosen by June 14, 2017 and the construction will likely happen in spring of 2018.

E. Demand Response

1. Recent Demand Response Developments

On August 16, 2016, Pacific Power presented on potential demand response pilot program at a Public Utility Commission of Oregon public meeting. At that time, no additional demand response pilot programs were recommended, as the Company was in the midst of re-assessing demand response potential in its 2017 Integrated Resource Plan (IRP), including an assessment of winter-focused demand response and potential opportunities from AMI, once deployed.

The *PacifiCorp Demand-Side Resource Potential Assessment for 2017-2036*[13] (DSM Resource Assessment), performed by Applied Energy Group, investigated the potential for, and cost of, summer- and winter- focused demand response options. The results of this assessment are used to evaluate demand response resources against supply-side alternatives in the Company's IRP. The following demand response options were analyzed in the 2017 DSM Resource Assessment:

- Central Air Conditioners Direct Load Control (DLC)
- Domestic Hot Water Heaters DLC
- Space Heating DLC
- Smart Thermostat DLC
- Smart Appliance DLC
- Room Air Conditioner DLC
- Irrigation Load Control
- Ice Energy Storage
- Curtailable Agreements
- Electric Vehicle Smart Charger DLC

A comparison of demand response resources selected in the preferred portfolios of the 2015 and 2017 IRPs is provided in Figure 7. As shown, while the 2017 IRP identified increased need for demand response, this need occurs later in the planning period, with the first new demand response resources selected in 2028, as compared to 2022 in the 2015 IRP. The increase in direct load control capacity is coincident with assumed coal unit retirements, signaling the importance of these capacity-based programs in PacifiCorp's transitioning resource mix.

[13] The full study is available on the Company's website. See Volume 3 for demand response inputs, methodology, and results. http://www.pacificorp.com/es/dsm.html

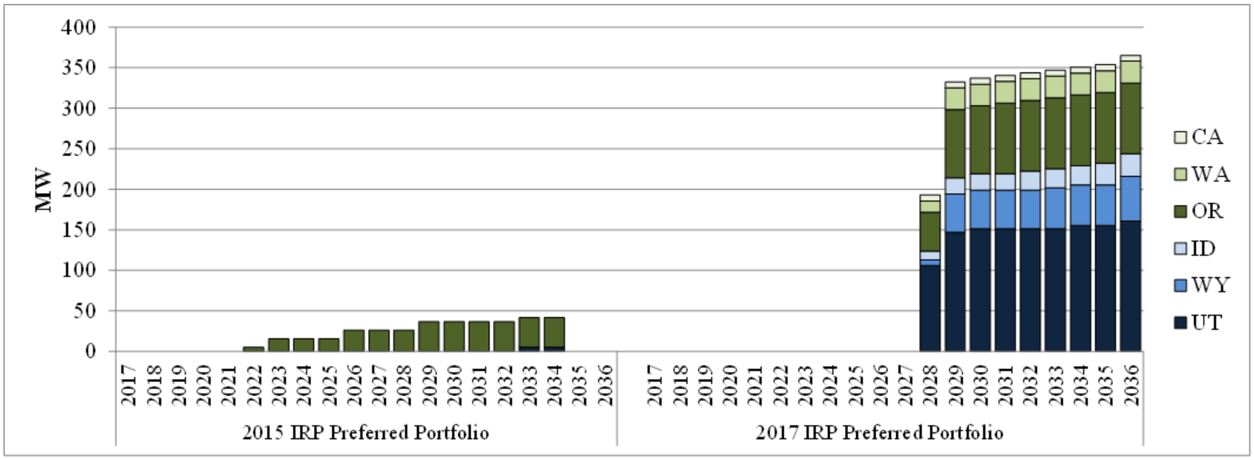

Figure 7 Comparison of Total Direct Load Control Capacity between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio

2. Irrigation Load Control

Project Summary

On May 3, 2016, the Public Utility Commission of Oregon (OPUC) approved the Company's request to implement a five-year irrigation load control pilot program for customers within the Oregon portion of the Klamath Basin. In the first year, 2016, customers with an aggregate capacity of 565 kW (based on June 2015 billing data) signed up and had equipment installed. One two-hour event was called on August 19, 2016. 281 kW were available for the event and there was 100% participation. On March 31, 2017, the Company filed a report on 2016 pilot program performance with the OPUC.[14]

Future Action and Timeline

During the 2017 season, no new customers will be added to the pilot program. One customer with two medium voltage sites enrolled, but not enabled in 2016, will be enabled in 2017, which would increase the available MW for 2017 and incorporate a new type of customer into the pilot program. The Company will dispatch the system a minimum of four times during the 2017 irrigation season, which began June 1st.

In 2017, the Company will issue a Request for Proposals (RFP) for load control services (including potential expansion of the pilot and other Pacific Power demand response products). Following the 2017 season, the company will reassess the size and sustainability of the pilot and make a determination for the future of the load control program.

[14] The report was filed in OPUC Docket No. ADV 242.

F. Distributed and Renewable Resource Enhancements

1. Distributed and Renewable Resources

PacifiCorp 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. PacifiCorp continues to see an increase in net metering customers across all of its service territory in 2017. A Pacific Power monthly report for June 2017 that indicates net metering and customer generation is provided in Appendix G – Pacific Power Net Metering and Customer Generation.

2. Distributed Energy Resources Deployment

PacifiCorp recognizes the role that distributed energy resources (DER) may play in the deferral or offset of traditional poles and wires infrastructure investments. The Company deployed a DER screening tool for transmission and distribution planners to utilize in comparing alternative DERs to traditional solutions. The tool screens for solar, energy storage and demand side management. The company has evaluated upcoming capital projects and examples are provided in Appendix F.

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[15], 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 on studies performed by an external contractor to inform the IRP process. The Company has integrated the tool into the 10 year capital planning process.

Future Actions and Timeline

The Company is currently engaged in two dockets in Oregon that contemplate valuing benefits and costs associated with solar (UM-1716) and energy storage (UM-1751). UM-1716 Resource Value of Solar (RVOS) is currently in Phase 1, which will define the appropriate elements for inclusion in the valuation methodology. Phase 2 of the proceeding will follow and define utility-specific values. The UM1751 Energy Storage docket is defining the use cases and the potential for stacking benefits. The Company issued an RFP

[15] NREL's PVWatts Calculator. *National Renewable Energy Laboratory* [Online]. Available: http://pvwatts.nrel.gov/

to perform the energy storage potential evaluation and awarded to DNV-GL. At the conclusion of these dockets that contemplate the application of the multiple system benefits the company plans to review the DER screening tool valuation methodology and perform updates, as appropriate. In 2017, PacifiCorp in collaboration with ETO will begin implementing targeted customer-sited energy efficiency technologies to understand and track whether these technologies have the ability to improve system operation during specific locational peak hours, with the possibility of deferring the need for system upgrades. Outcomes of this pilot will be used to validate the tool screening method.

It is anticipated that for future budgeting cycles, proposed system reinforcements will include DER solutions as part of the analysis and their respective documentation recommendations and proposals. Where feasible and cost-effective, DER solutions are expected to supplant traditional solutions for implementation. Once resolved, Pacific Power will incorporate the resulting information from the matters currently in front of the Commission, which examine the multiple system benefits of resources, into DER analysis for future iterations of the screening tool.

3. Interconnection Standards and Smart Inverters

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 DERs projected to increase through 2040[16] and necessitate standards be identified and followed to ensure a unified system.

PacifiCorp'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*[17]
- UL 1741 – *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*[18]

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

[16] 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

[17] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. *IEEE* [Online]. Available: http://grouper.ieee.org/groups/scc21/1547/1547_index.html

[18] 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

DERs and address the technical and test requirements for systems under 10 MW. The IEEE 1547 standard was published in 2003 and focuses on the technical specifications for, and testing of, the interconnection. The standard also provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance 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 DERs on electric power systems. IEEE 1547 is composed 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 allowed in IEEE 1547. The amendment later initiated a full revision of IEEE 1547 in consideration of evolving technology and functionalities of modern inverter-based DER systems.

Company Participation

PacifiCorp 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.

Several sections of IEEE 1547 are undergoing significant changes including but not limited to voltage regulation, response to abnormal voltage and frequency conditions, islanding, power quality, and interoperability. 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 Q3 2017 and published in Q1 2018.

In September 2016, the UL 1741 working group published UL 1741 Supplement SA to define the evaluation criteria for utility interactive inverters with grid support functionalities. The requirements provided in the revised standard is intended to validate compliance with grid interactive functions which are not covered in IEEE 1547-2003. These grid support functions may include but are not limited to voltage and frequency ride-through and active and reactive power control. A few inverter manufacturers have started to test and certify inverters to the new UL 1741 standard. 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 Supplement SA 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 Oregon, OAR 860-082-0025 (Applications to Interconnect a Small Generator Facility)[19] 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.

[19] 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

Bi-Directional Regulator Control Standards

Regulator control standards were modified to include bi-directional functionalities in preparation for expected rise in DERs. Pacific Power purchases regulators that meet ANSI/IEEE standard C57.15 which specifies 50,000 operations under load for the contact life. The standard also specifies the tap changer must handle 500,000 mechanical operations without load (design test). Whether the regulators are single-phase feeder, single-phase substation, or three-phase substation units, the number of tap change operations is not recorded or used in any decision making regarding maintenance or replacement planning at this time.

It is important to consider device lifetime with these new devices since they have the potential to operate more frequently given their bi-directional capability. Pacific Power experienced 33 failures from 2008 – 2015, averaging four failures per year for a failure rate of about 2.7% annually. As three phase regulators fail, Pacific Power replaces the units with three single phase regulators. The Company is experiencing very few single phase regulator failures annually and when they do fail, it's usually a spring in the tap changer that eventually gets replaced and then the unit is used as a spare and placed back into service. Based on Pacific Power's experience, newer regulators appear to be performing better than older regulators. The company will continue to monitor the performance of regulators.

Future Actions

PacifiCorp intends to implement the advanced inverter functionality recommendations to be defined in the IEEE 1547 standard, however, the company will await publication of the revised IEEE 1547 standard to update internal interconnection standards and policies. There are currently no other updates for 2017.

4. Transportation Electrification

Through May 2017, 13,074 plug-in electric vehicles had been sold in Oregon.[20] Based on ZIP code-level data provided by the Oregon Department of Environmental Quality, it is estimated that roughly one third of the state's plug-in electric vehicles are registered in Pacific Power's service territory. Given the low number of plug-in

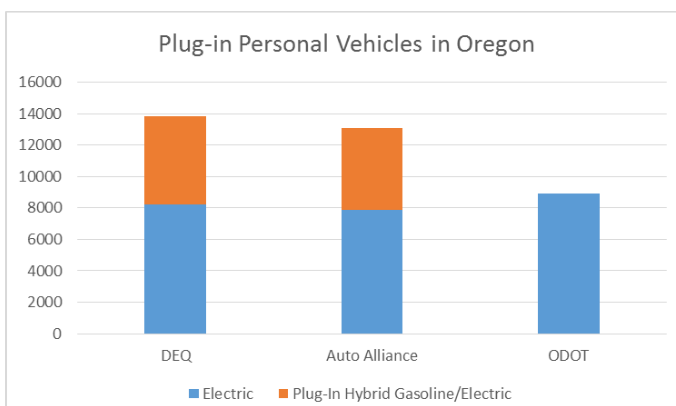

Figure 8 Plug-in Personal Vehicles in Oregon

[20] Auto Alliance, ZEV Sales Dashboard, https://autoalliance.org/energy-environment/zev-sales-dashboard/ (accessed July 27th, 2017)

electric vehicles currently, the Company has not yet experienced major distribution system impacts from these vehicles; however, as transportation electrification increases, it will be important for the Company to understand potential impacts on the distribution system associated with this increased adoption. In Oregon, Senate Bill 1547,[21] known as the Clean Electricity and Coal Transition Act, reaffirms the state's commitment to transportation electrification. The bill requires electric utilities to develop programs and infrastructure necessary to accelerate transportation electrification for energy efficiency and carbon reduction purposes.

In Utah, Senate Bill 115[22], 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.

Project Summary

Given the rapidly evolving state of the market, Pacific Power's strategy to enter this new market focuses on gathering information and remaining responsive to market conditions.

On December 27, 2016, Pacific Power proposed its initial set of transportation electrification pilot programs to the OPUC.[23] These initial pilot programs, designed based on stakeholder input and market research will test different market intervention strategies and allow the Company to gather experience and data that can be used for future system and program planning. At OPUC Staff's request, the Company filed a supplemental application on April 12, 2017, to provide additional information on the transportation electrification market, barriers to increased adoption, and program objectives and details.

Future Action and Timeline

The Company is currently participating in an OPUC process to develop parameters and processes for developing utility long-term transportation electrification plans. The Company looks forward to continued engagement with stakeholders as it implements the

[21] Oregon Senate Bill 1547. *Oregon State Legislature* [Online]. Available: https://olis.leg.state.or.us/liz/2016R1/Measures/Overview/SB1547
[22] Utah Senate Bill 1547. *Utah State Legislature* [Online]. Available: http://le.utah.gov/~2016/bills/static/SB0115.html
[23] OPUC Docket No. UM-1810.

proposed pilot programs and considers the potential for additional transportation electrification programs.

5. <u>Targeted Energy Efficiency</u>

Pacific Power is working with the Energy Trust of Oregon to identify areas of its Oregon service area where targeted community focused efforts could potentially help improve system operation during specific locational peak hours and possibly defer traditional system investments. Another key objective of this work is to understand the time needed for deployment of existing program services can be deployed to a focused area and whether deployment could be accelerated.

Figure 9 Energy Efficiency Pilot Targeted Area

In 2017, Pacific Power and the Energy Trust of Oregon developed and implemented a learning pilot project to deploy in the North Santiam Canyon. The objective is to measure the impacts of deploying increased marketing and outreach of existing Energy Trust of Oregon energy efficiency programs to residential, commercial, and industrial customers in targeted locations. . The results of this pilot project will inform whether to deploy targeted existing energy efficiency projects in additional locations in the future. Through this pilot, the Energy Trust of Oregon will investigate its ability to:

- Measure and quantify the peak demand reduction that can be achieved through energy efficiency offerings in the identified geographic area.
- Document and evaluate the effectiveness of replicable targeted energy-efficiency program design that can be rapidly deployed in targeted areas to reduce energy and peak demand at no additional cost.
- Develop processes for design and deployment whereby Pacific Power and Energy Trust staff take coordinated actions in support of the pilot project related to the marketing, program delivery, and measurement of impacts.
- Determine what, if any, changes to existing program offerings and/or new offerings might make targeted deployment more effective.

G. Customer Communications and Programs

1. Oregon AMI Customer Communications and Programs

A customer energy usage website that provides customers with usage and billing information will be introduced as a component of Pacific Power's Oregon AMI project. The energy usage website 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.

Advanced Metering Infrastructure Strategy

Customer engagement – Forms and Process

A suite of customer-centric service options will be implemented on December 8, 2017, providing customers with self-service options to manage their account information in real time through use of digital technologies.

Project Description and Analysis:

Today PacifiCorp customers can use online static web forms to request to start, stop, or transfer services. These static forms are manually processed by our contact center.

The Company will deploy a new web self-service solution to offer a customer-friendly and efficient self-service form to request basic services, allowing customers to complete requests at their convenience and reducing back office work load for contact center personnel.

Internal features include:

- Real-time account updates without agent intervention
- Reduced back-office work for contact center personnel
- Increased agent availability to take incoming customer phone calls

Customer Facing features include:

- New and improved customer-centric, self-service options for Start, Stop, Move and Account Updates.
- Real-time account updates, eliminating 24-48 hours waiting period.
- Start, Stop and Move service requests will generally occur automatically on the customer requested date.
- An account number will be provided in real-time to new customers, confirming the transaction.
- Move (transfer) requests will be processed behind the web login to enable existing customers to complete their request with minimal inputs.

- Option to receive notification of the closing bill via email in addition to the mailed copy.
- Step-by-step process to enable customer to complete their request successfully.

Project Timeline

Enhanced Energy Usage Web Features will go live with customer data in July of 2018 and will allow the capture of interval energy usage every hour for residential customers and every 15 minutes for non-residential customers. The interval energy usage information along with monthly bill amounts for non-AMI customers will be presented on the Company's external facing website behind the secure login to assist customers with self-management of their consumption.

Customer engagement – Data and Display

Project Description and Analysis

Energy usage information will be presented along with temperature data to assist customers evaluating the impact of weather on their energy consumption. Customers will have 13 months data displayed when available. Specifics include:

- Residential smart meter customers (Schedule 4) will have hourly, daily, and monthly energy consumption information provided graphically in various time scales (24 hours, one week, one month, and 13 months for up to 24 months) with temperature overlays.
- Small to mid-size non-residential smart meter customers (Schedule 23 and 28) will have 15 minute, hourly, daily, and monthly energy consumption information provided graphically in various time scales (24 hours, one week, one month, and 13 months for up to 24 months) with temperature overlays.
- Residential and non-residential smart meter customers will have estimated cost-to-date and projected bill calculations presented and updated daily after the first week of a billing cycle.
- Residential and non-residential smart meter customers will be able to set a dollar threshold and receive an alert text messages or email if the monthly bill is projected to exceed the limit based on usage to date for the monthly bill.

Non-smart meter customers (all six states)

- Non-smart meter customers will continue to be presented with 13-months of energy usage with average monthly temperature overlaid on the graph and in the table.

Future Action

Monthly cost estimates based on weather projections will be evaluated as a Phase 2 improvement during 2018.

Customer Communications and Programs: Outage map on website and mobile app Project

Project summary

Pacific Power is currently engaged in a project that will deploy an outage map for each state. This content will sit on the public web site in front of the secure log in on the customer facing website and on the company's mobile app. Delivery of the outage map went live summer of 2016, with the mobile app to follow summer of 2017. A follow on project will remove the requirement to login to report an outage on both the web site and mobile app.

Project Description and Analysis

This project deployed outage maps using the refined web content management and GIS solutions. The proposed interactive mapping solution maps the locations of outages based upon the Pacific Power and Rocky Mountain Power electrical network equipment tied to their outage event (device or service transformer) and associate those mapping locations to the relevant outage details.

Future Action and Timeline

To improve the customer experience during outages, additional initiatives are currently being implemented to improve the frequency and content of information provided to customers utilizing customer requested communications channels, social media, and traditional media.

Customer Communications and Programs: Customer preference center web, text, email, voice messaging options

Project Summary

The preference center project will roll out on December 8, 2017 and offer customers the opportunity to enroll in courtesy alerts via email, text, or phone messages. The Preference Center will be accessed through the secure login section of our customer facing websites or when a customer is working with a contact center agent.

Project Description and Analysis

The preference center key features are:

- Set communication channel preference to receive selected information via email, voice, or text message. Select communications channel preferences for billing notices, courtesy pay reminders, payment confirmation, billing projection threshold, and outage information.
- Expand on the current communication channel of email to include text messaging or voice messaging.
- Provide the ability for customers to set their communication preferences via the web or by speaking to a contact center agent.
- Enable customers to pre-select the communication channel when an outage is reported at their location.

- Compliance with the Oregon regulatory noticing prior to involuntary disconnection of service rules.

Future Action and Timeline

The solution will include a design that will accommodate for future expansion of the preference center to the mobile application environment.

Operational Excellence: Automation of connection, reconnection, and disconnection of smart meters, opt-out considerations.

Project Description

Connection:

- For smart meters with automated or "remote" connection/disconnect capabilities (approximately 88%), work requests will be processed through the Advance Metering Management (AMM) system within an hour of payment. If the signal fails to successfully connect the service, a work order will be generated to read the meter and connect service within 24 hours. Schedule 300 will be updated to reflect fees appropriate for meters capable of automated connections to eliminate after-hour charges.

Voluntary Disconnection:

- For customers at premises with a smart meter, when a customer requests to close their account, an order for the time and date of the requested disconnection will be processed through the AMM system. . If the signal fails to disconnect the service, a work order will be generated to read the meter and disconnect the service.

Involuntary Disconnection:

- For customers at premises with a smart meter, following the mandatory notifications of pending disconnection of service as outlined in the Oregon Administrative Code, a disconnect order is issued and processed through the AMI system if payment or payment arrangement are not made. If the signal fails to disconnect the service, a work order will be generated to read the meter and disconnect the service.

Reconnection (following involuntary disconnection):

- Following payment, the system will automatically send through the AMM system a signal to reconnect service. If the signal fails to successfully reconnect, a work order will be generated to read the meter and connect the service within 24 hours.
- Schedule 300 will be updated to reflect appropriate reconnection fees for meters capable of automated reconnections.

Table 7 Approved Schedule 300 Charges

	Installation of non-radio frequency meter	Removal of Non-Radio Frequency Meter	Manually obtained monthly meter reading
Proposed Schedule 300 charges reflecting actual average cost	$169	$137	$36
Company installs radio frequency meter before January 1, 2018, in the normal course of business	Does not apply	Applies	Applies
Customer refuses radio frequency meter before installation and after January 1, 2018, during mass smart meter deployment	Does not apply	Applies	Applies
Company installs radio frequency meter after January 1, 2018	Applies	Applies	Applies

Pacific Power submitted Advice Filing No. 17-001 on January 4, 2017 requesting the inclusion of op-out provisions in the Company's Rule 8, Metering and Schedule 300, Charges as Defined by Rules and Regulations. The opt-out provisions allow customers the option to relocate a meter, change the meter to a non-standard, non-radio frequency meter requiring manual meter reading, or a combination of both. Order No. 17-113 approved the changes to Rule 8, Metering and Schedule 300, Charges as Defined by Rules and Regulations, with an effective date of March 22, 2017, with the conditions that Pacific Power notifies customers about metering options prior to the replacement of existing meters with AMI meters and that Pacific Power submits a report to the commission within one year after the Oregon AMI rollout has been substantially completed including the information requested in Order No. 17-113. This report will be included as an appendix in the Smart Grid Report of the appropriate year. If customers choose to have the non-radio frequency meter removed within six months of installation, Pacific Power will install a standard, radio frequency meter and refund the removal charge on the customer's next monthly service billing. Monthly meter reading charges assessed during the period the non-radio frequency meter was installed will not be refunded. Further details on the filing may be found posted on the OPUC website.[24]

[24] OPUC further details on Schedule 300 may be found online at: http://edocs.puc.state.or.us/efdocs/UAB/adv495uab142242.pdf

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 8. Oregon AMI network build-out and meter deployment began in Q2 2016 with expected completion in 2019. CYME circuit analysis software implementation was completed in Q4 2016. NERC MOD-33 requirements will be met by enforcement date of May 2017. Transportation electrification pilot programs were proposed at the end of 2016 to satisfy Oregon SB 1547. 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, publication of standards/requirements in Q2 2017, and approval in 2018.

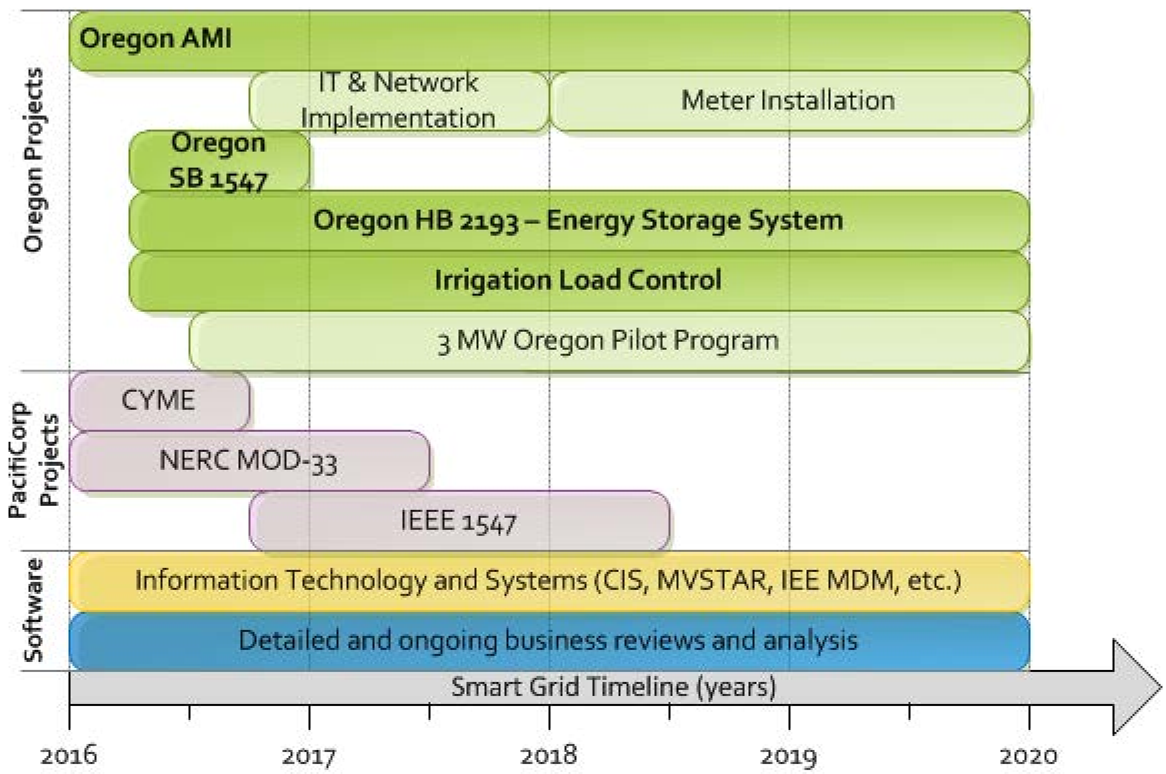

Figure 10 Original Smart Grid Roadmap

VII. Conclusion

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

Appendix A – 2016 Stakeholder Recommendations and Comments

A summary of 2016 stakeholder recommendations and action taken by the Company is given in Table 8. Table 9 includes a summary of informal and formal stakeholder comments and the resulting company responses or actions.

Table 8 Summary of Order No. 16-476 Recommendations and Company Actions

Stakeholder	Recommendation Description	Company Actions	Page(s)
OPUC	1. Include a high-level table summary of all stakeholder informal comments and corresponding Company responses as an appendix in future smart grid reports.	High-level summary included on page 3 for the formal comments. Informal comments and formal comments are captured in Appendix A.	3, Appendix A
OPUC	2. The Company to provide an AMI Roadmap outlining a framework for tracking: • AMI costs and cost savings • reliability improvement and reconnection times • mitigating technology obsolescence risk • customer engagement • analysis of AMI data and data application • transition from AMI "capabilities" to "functionalities" and clearly defined milestones that would motivate this change	A framework for tracking AMI costs and cost savings, reliability improvements, reconnection times, mitigating technology obsolescence risk, customer engagement, analysis of AMI data and data applications, and transitioning from AMI "capabilities" to "functionalities" and clearly defined milestones that would motivate this change are included throughout the report as appropriate. If tracking would be infeasible or inappropriate, that is addressed in the report.	Throughout
OPUC	3. Company to apprise the Commission of any new developments of new Dynamic Line Rating (DLR) projects.	No installations currently in or planned in Oregon.	20
OPUC	4. Company to continue to apprise the Commission of new success, or lack thereof, of remedial action scheme(s) in the form of redundant relays.	RAS installed is in service and operating appropriately with no future action anticipated.	20
OPUC	5. Company to provide a comprehensive narrative explaining its developments, or lack thereof, both past and present, with Peak Reliability and WECC and its decision to stop its transfer of PMU data to Peak Reliability.	Our experience spotlighted importance of data management and asset management policies. Lack of tools and information caused PacifiCorp to stop the transfer of data to Peak RC. We may restart the stream in the future if useful tools become available.	20-22

OPUC	6. Provide an update to its irrigation load control pilot and the table on page 32 of the 2016 Smart Grid Report including Oregon data when it is available.	A project update has been included in the report and the load control table has been updated.	43
OPUC	7. Company should provide a summary of its review to investigate linking distribution devices to its OMS system and energy management system.	Summary provided.	37
OPUC	8. Company to update Commission if planning on installing Field Area Network.	The company is looking at enabling communications in location specific areas.	39
OPUC	9. Company to work with Staff and interested stakeholders to schedule a demonstration no later than April 30, 2017.	Demonstration of CYME conducted March 28th, 2017.	39, 40
OPUC	10. Company to apprise Commission of demand response developments in future smart grid projects.	Update of demand response programs provided.	42-43
OPUC	11. Company should provide its Distributed Energy Resource (DER) analysis, including how Company has utilized the transmission and distribution planning tool.	DER project updated and DER template/tool included in Appendix E.	44-45

Table 9 2016 Informal and Formal Stakeholder Comments

Subject	Informal/Formal Comments	Company Response
PMU	OPUC: Clarify how the company plans to use PMU data once it is available. ODOE: Interested in the lessons learned from identifying and analyzing system vulnerabilities and disturbances and in additional information on using synchrophasor data increasing real-time situational awareness. OPUC: Company should follow through with its commitment to address ODOE's questions.	PMU data's greatest value is in situational awareness. We already have situational awareness through SCADA so we do not plan to utilize PMU data to increase this, however, we do collect it and use it for event analysis and modeling and planning support. We will no longer send Peak Reliability PMU data as part of WISP, but will reconsider when valuable tools are available. This matter is addressed further in Table 9 and in the Transmission Synchrophasor Demonstration Project section of the 2017 Smart Grid Report.

AMI	OPUC: Staff was concerned with the AMI project non-deliverable functionalities. Staff asked for a cost-benefit estimation of decreased response time, reconnection functionality, and outage detection functionality ODOE: Why will customers not be given access to hourly data in real time? Will AMI provide data to home area networks?	Reconnection estimates at the time were communicated to be 1 to 5 hours. We have updated this estimate in this report to disconnection and reconnection to be normally within the hour. Total costs of functionalities are embedded in the project, possible estimates were provided. PacifiCorp will pursue additional AMI capabilities after they can be shown to provide value to customers. It is possible to integrate smart grid technology with home area networks. PacifiCorp prefers to validate data prior to presentation to the customer.
RAS	OPUC: Are there disadvantages to using redundant relays instead of thermal replicating relays and are there advantages to redundant relays other than cost?	Redundant relays are simpler with lower maintenance requirements.
Load Control Pilot	OPUC: Provide load curtailment data for all seven 2015 load curtailment events.	The Company provided a table with the seven events and their estimated load reductions. Staff requested an update to the Oregon irrigation load control pilot and data table when available in Recommendation No. 6 for the 2017 Report.
Fuse Saving	OPUC: What is needed to establish communication with Fuse Savings devices and what is needed to integrate them into SCADA? Staff recommended we provide an update investigating distribution devices to OMS and EMS for the 2017 Smart Grid Report.	Barriers for integrating them into OMS and Monarch are the need for a field area network, data-program interface, and management system modifications to allow field data acceptance.
Smart Devices	OPUC: Staff requested updates on the smart grid capabilities of capacitor banks, reclosers, and regulator bank controls.	The devices have communication capability, but have not had communications enabled as there is not yet a field area network or a data handling system.
CFCI	OPUC: Staff requested the Company provide an update on the status of the CFCI project.	CFCIs would be incompatible with the planned AMI field area network, but the company uses integrated cellular coverage for CFCI. The Company states that it is investigating the cost of integrating CFCI with OMS. No further action was asked by the OPUC.

CYME	OPUC: List benefits comparing CYME to ABB FeederAll. Is CYME going to use AMI data?	The Company provided a list of CYME benefits. The Company offered Staff the opportunity to see a CYME demonstration. Staff accepted and the company conducted the demonstration on 03/28/2017. Staff was satisfied by the demonstration.
Cool Keeper	OPUC: Does the Company regularly runs analytics on the Cool Keeper program and what are the garnered quantitative comparisons?	Information gathered by the company analysis of the Cool Keeper program includes daily resource analysis, hourly forecasting, event validation, customer segmentation, and other "ad hoc" analyses.
DER Template	OPUC: Staff looks forward to an update to the DER template in the 2017 Smart Grid Report. ODOE supports the use of the DER template to demonstrate multiple system benefit for DER, not just a focus on DER as a single investment alternative.	The Company will include a summary of DER analysis in addition to examples of its analysis. The Company addresses ODOE concerns in this 2017 Smart Grid Report.

Appendix B – 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 9.

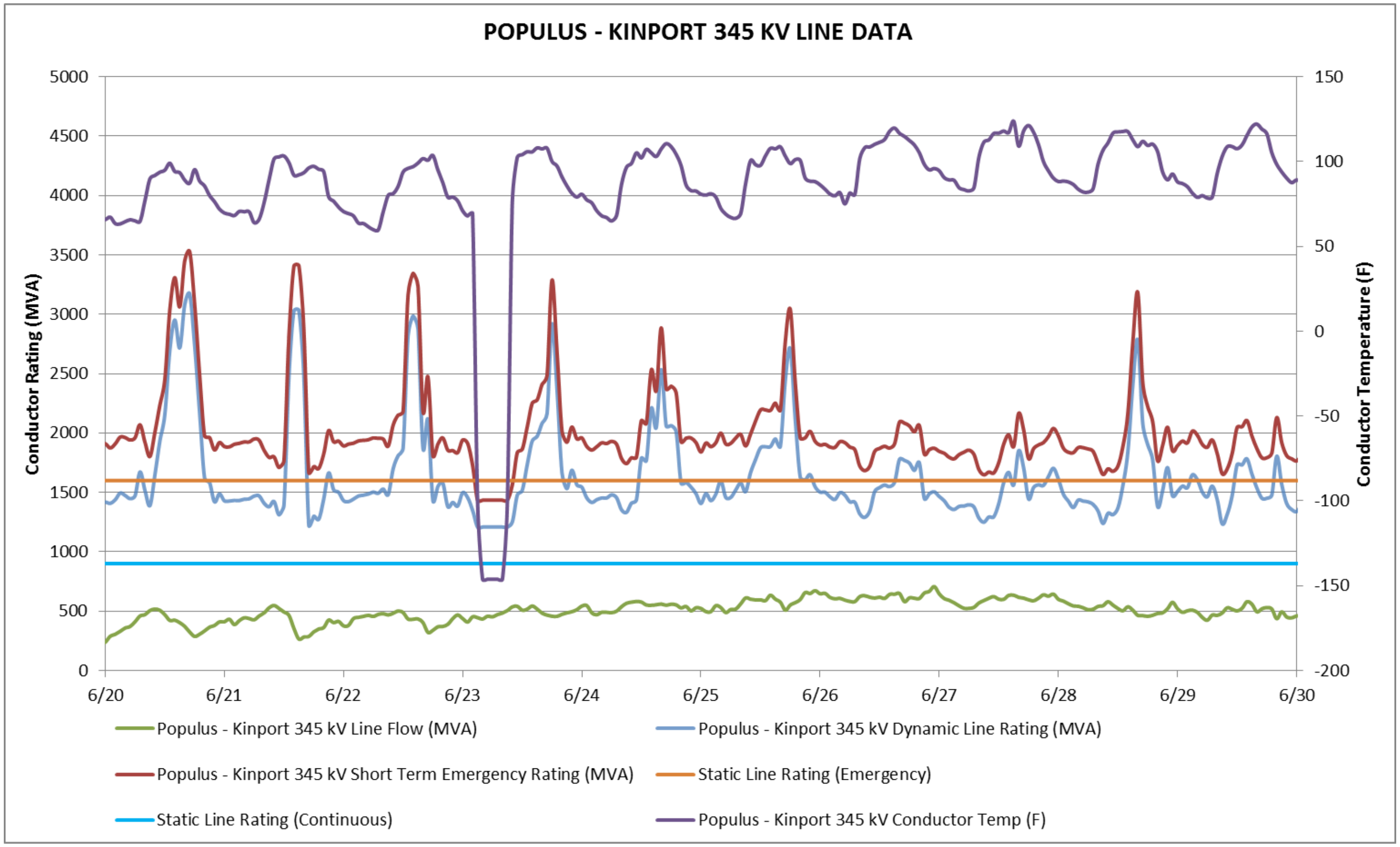

Figure 11 Dynamic Line Rating for West of Populus

Appendix C – 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 10.

Table 10 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 D – MOD-033 Model Validation

Figure 10 shows the input PMU voltage data of actual system voltage compared against a power flow model. Figures 11 and 12 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.

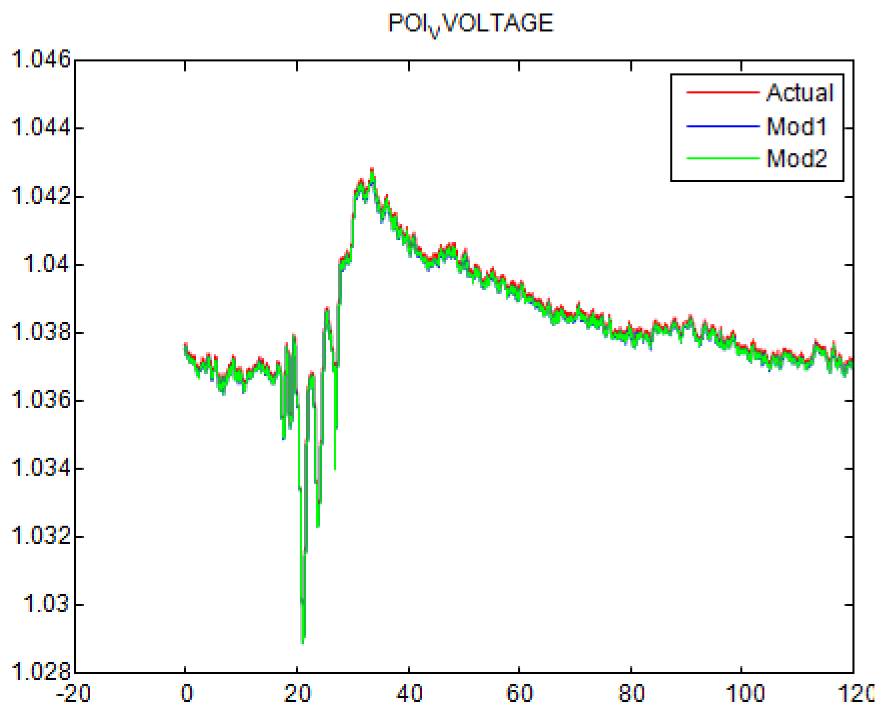

Figure 12 PMU Input Data

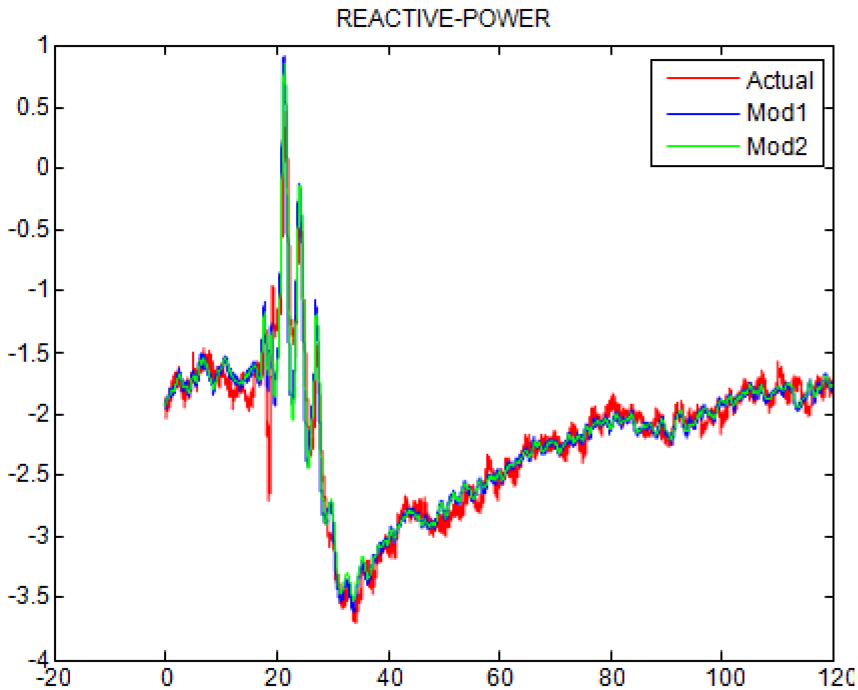

Figure 13 Actual PMU Data Validates Model

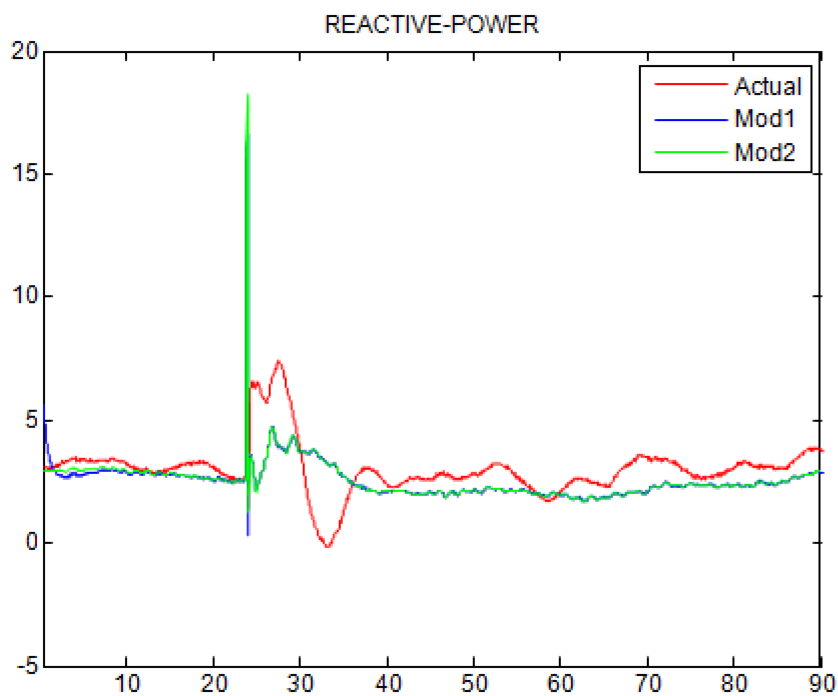

Figure 14 Actual PMU Data Invalidates Model

Appendix E – DER Example Template

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

Distributed Energy Resources
Alternative Solutions Template

BERKSHIRE HATHAWAY ENERGY

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.

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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.

<u>Demand Side Management</u>

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	13.33	MVA	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	1.25%	%	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	13.50	13.67	13.84	14.01	14.19	14.37	14.55	14.73	14.91	15.10
Known new loads	-			-	-	-	-	-	-	-
Total Load Estimate	13.50	13.67	13.84	14.01	14.19	14.37	14.55	14.73	14.91	15.10

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
12.50	105%	13.13		13.6	1.2%	90%	11.25	2.25

Base Assumptions

Minimum DER MWac Output based on Planning Criteria Loading		2.25	DER MWac
Safety Margin for minimum DER MWac Output (Default is 10%)	10%	2.48	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	$5,000.00	$ Estimate

Solar Only Alternative

Is Solar Alternative possible?			No	Yes/No?
Solar Size Assumption	3.94	DER MWac	3.65	DER MWdc
Solar Land Assumption			26.87	acres
Summary Cost Estimate for Solar Only Alternative			$ 8,411,108	$ Estimate

Battery Only Alternative

Is Battery Alternative possible?	Yes	Yes/No?
Peak MW	3.00	MVA
Peak MWh	14.00	MVAh
Summary Cost Estimate for Battery Only Alternative	$ 12,771,288	$ 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)	3.94	DER MWac	3.65	DER MWdc
Solar Land Assumption			26.87	acres
Summary Cost Estimate for Solar Portion			$ 8,411,108	$ Estimate
Peak Battery MW (use formula to refer to cell on Solar & Battery tab)			2.00	MW
Peak Battery MWh (use formula to refer to cell on Solar & Battery tab)			4.00	MWh
Summary Cost Estimate for Battery Portion (use formula to refer to cell on Solar & Battery tab)			$ 3,920,367	$ Estimate
Summary Cost Estimate for Solar & Battery Alternative (use formula to refer to cell on Solar & Battery tab)			$ 12,331,476	$ 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)	287	kW
Summary Cost Estimate for DSM Alternative	$ 32,394	$ Estimate

Traditional Alternative

Construct new distribution substation inside the fenced area at Calapooya substation to provide capacity relief to Brownsville Substation and to improve reliability in the Brownsville and Tangent areas.

Summary Cost Estimate for Traditional Alternative	$ 2,403,531	$ Estimate

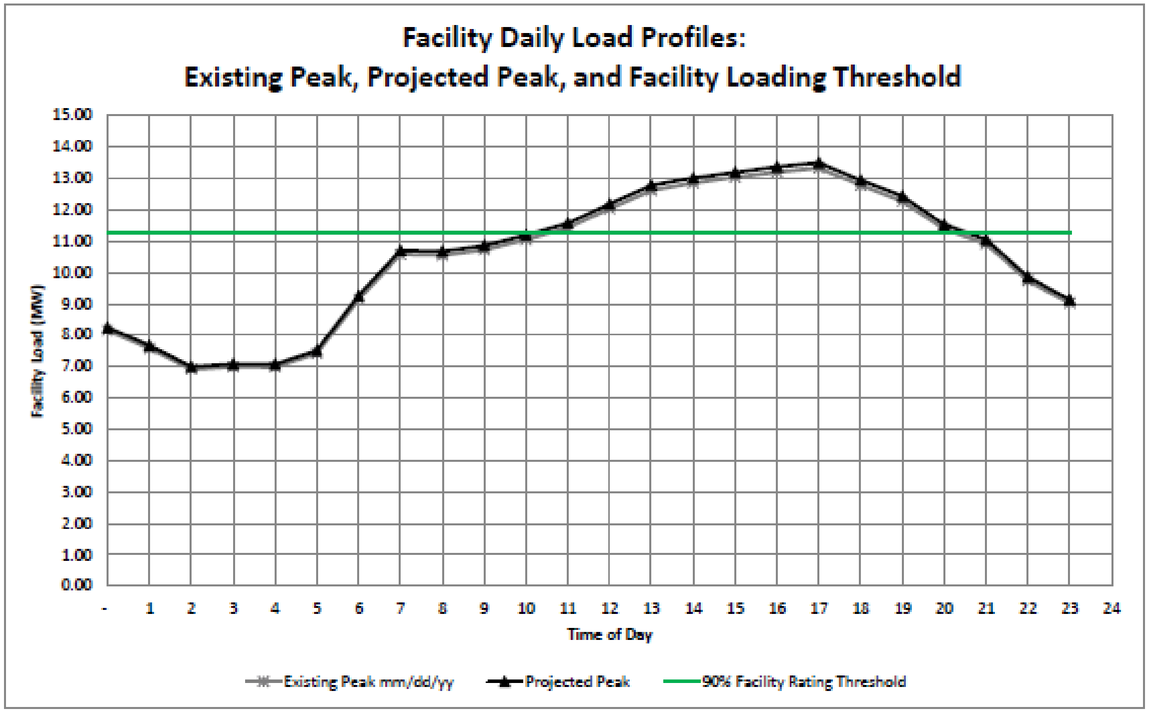
Facility Load Profile Data

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.

SCADA data available?	YES

% Increase from Existing Peak to Projected Peak: 1.2%

Hour of Day	Existing Peak mm/dd/yy	Projected Peak	% Facility Rating	90% Facility Rating Threshold	MW above Threshold
	Max 13.33	Max 13.50	12.50		
-	8.15	8.25	66.0%	11.25	(3.00)
1	7.57	7.67	61.3%	11.25	(3.58)
2	6.91	7.00	56.0%	11.25	(4.25)
3	7.00	7.09	56.7%	11.25	(4.16)
4	6.99	7.08	56.6%	11.25	(4.17)
5	7.42	7.51	60.1%	11.25	(3.74)
6	9.15	9.26	74.1%	11.25	(1.99)
7	10.58	10.71	85.7%	11.25	(0.54)
8	10.55	10.68	85.4%	11.25	(0.57)
9	10.73	10.86	86.9%	11.25	(0.39)
10	11.05	11.19	89.5%	11.25	(0.06)
11	11.43	11.57	92.5%	11.25	0.32
12	12.04	12.19	97.5%	11.25	0.94
13	12.62	12.77	102.2%	11.25	1.52
14	12.85	13.01	104.1%	11.25	1.76
15	13.03	13.19	105.6%	11.25	1.94
16	13.20	13.37	106.9%	11.25	2.12
17	13.33	13.50	108.0%	11.25	2.25
18	12.78	12.94	103.5%	11.25	1.69
19	12.28	12.43	99.4%	11.25	1.18
20	11.39	11.53	92.2%	11.25	0.28
21	10.91	11.05	88.4%	11.25	(0.20)
22	9.74	9.86	78.9%	11.25	(1.39)
23	9.02	9.14	73.1%	11.25	(2.11)



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

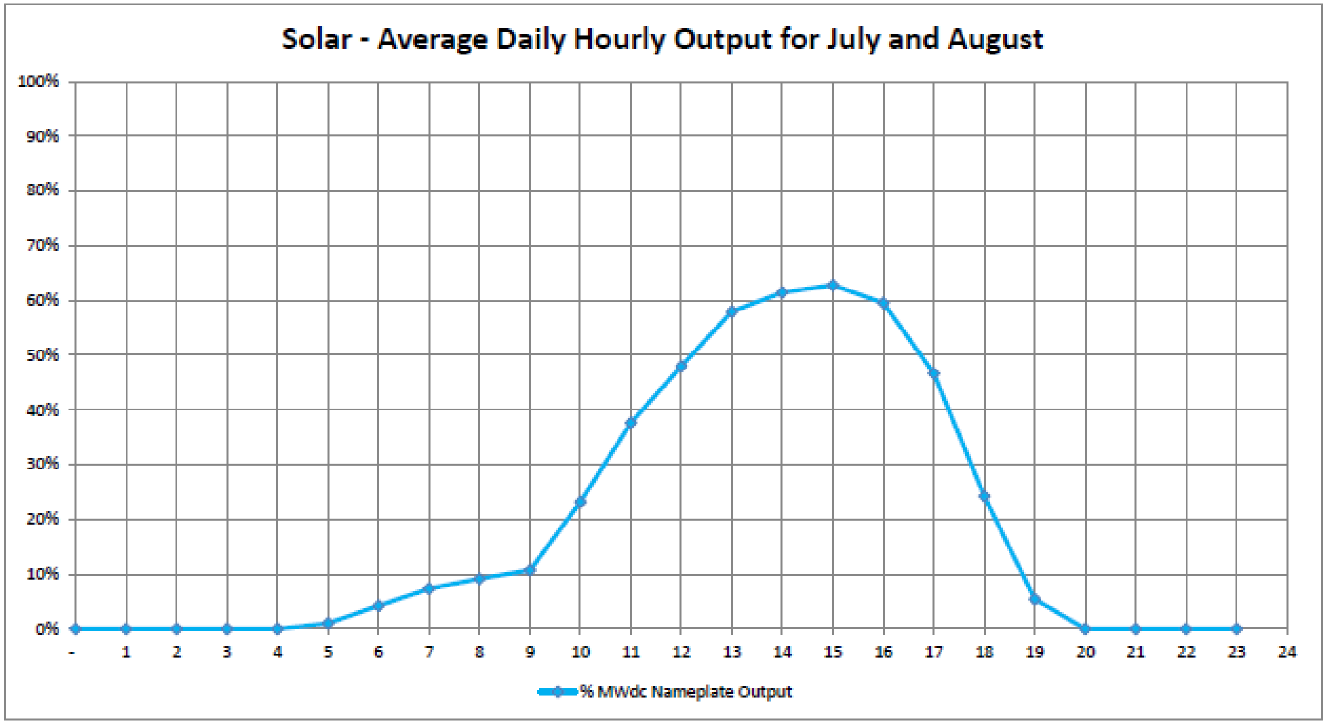
PVWatts: Hourly PV Performance Data		**In the PVWatts Calculator. enter site specific information and use default information as needed**
Requested Location:	brownsville, oregon	**Enter Site Location: City, State. Use nearest available solar data or a combination of locations.**
Location:	CORVALLIS MUNI, OR	Location Specific
Lat (deg N):	44.48	Populated from Location Specific from the City, State and Weather Location selected
Long (deg W):	123.28	Populated from Location Specific from the City, State and Weather Location selected
Elev (m):	77	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 earlier.**
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 ($/kWh):	0.09	Default Selection
Initial Cost	3.3	Default Selection
Cost of Electricity Generated by System ($/kWh):	11.2	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 for July and August

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
		62.78%
Hour of Day	**DC Output (W)**	**% MWdc Nameplate Output**
-	-	0.00%
1	-	0.00%
2	-	0.00%
3	-	0.00%
4	-	0.00%
5	105	1.05%
6	425	4.25%
7	734	7.34%
8	913	9.13%
9	1,074	10.74%
10	2,318	23.18%
11	3,763	37.63%
12	4,796	47.96%
13	5,795	57.95%
14	6,147	61.47%
15	6,278	62.78%
16	5,955	59.55%
17	4,669	46.69%
18	2,424	24.24%
19	547	5.47%
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

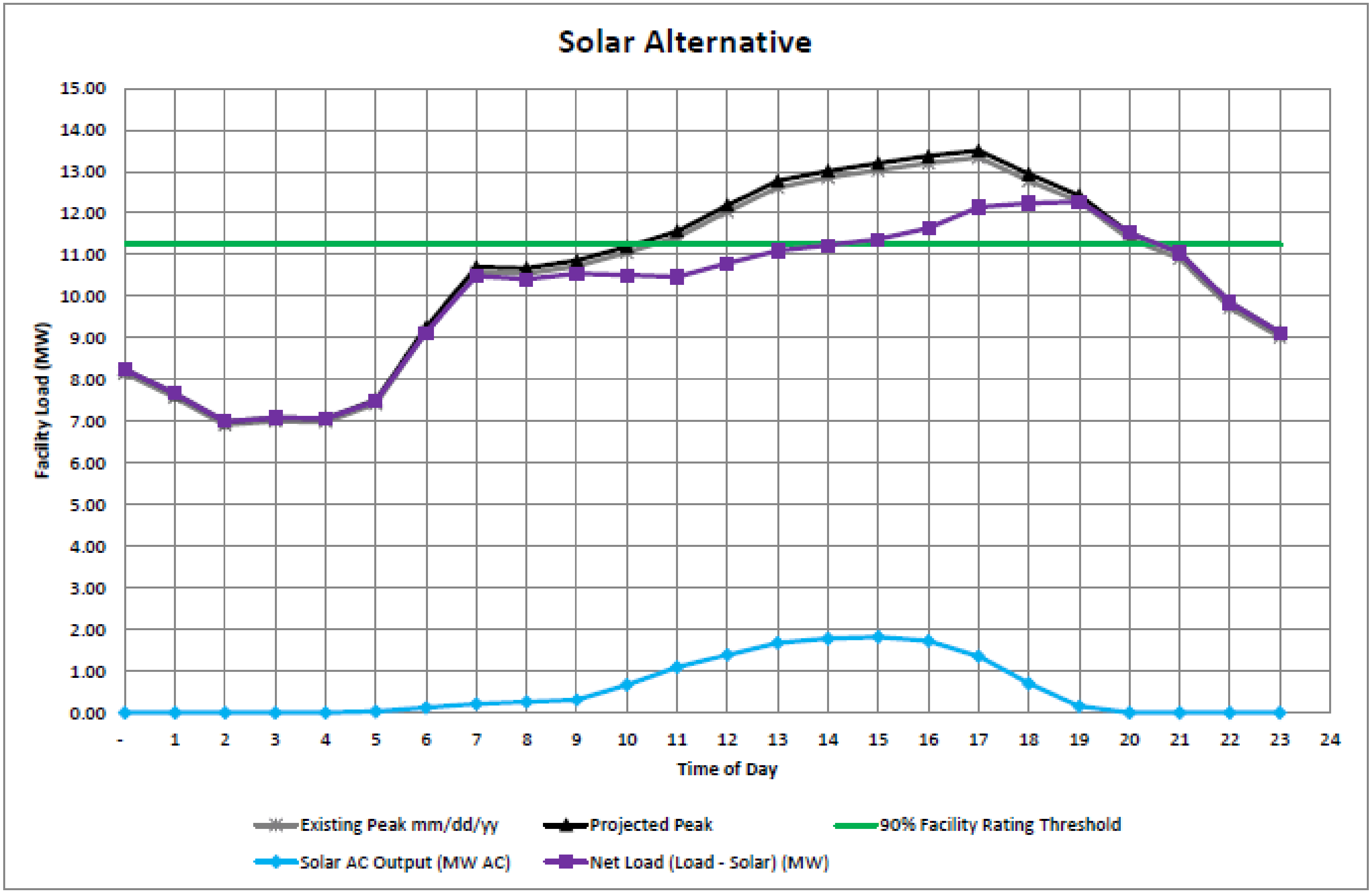
% Increase from Existing Peak to Projected Peak: 1.2%

Solar Information

2.25 = 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
	13.33	13.50	12.50			62.78%	3.23								3.02		3.69
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)**
-	8.15	8.25	66.0%	11.25	(3.00)	0.00%	-	-	8.25	-	-	-	-	-	-	-	-
1	7.57	7.67	61.3%	11.25	(3.58)	0.00%	-	-	7.67	-	-	-	-	-	-	-	-
2	6.91	7.00	56.0%	11.25	(4.25)	0.00%	-	-	7.00	-	-	-	-	-	-	-	-
3	7.00	7.09	56.7%	11.25	(4.16)	0.00%	-	-	7.09	-	-	-	-	-	-	-	-
4	6.99	7.08	56.6%	11.25	(4.17)	0.00%	-	-	7.08	-	-	-	-	-	-	-	-
5	7.42	7.51	60.1%	11.25	(3.74)	1.05%	0.03	0.03	7.48	-	0.03	-	0.03	0.02	0.02	-	-
6	9.15	9.26	74.1%	11.25	(1.99)	4.25%	0.14	0.12	9.14	-	0.12	-	0.12	0.08	0.09	-	-
7	10.58	10.71	85.7%	11.25	(0.54)	7.34%	0.24	0.21	10.49	-	0.21	-	0.21	0.17	0.26	-	-
8	10.55	10.68	85.4%	11.25	(0.57)	9.13%	0.29	0.27	10.41	-	0.27	-	0.27	0.24	0.50	-	-
9	10.73	10.86	86.9%	11.25	(0.39)	10.74%	0.35	0.31	10.55	-	0.31	-	0.31	0.29	0.79	-	-
10	11.05	11.19	89.5%	11.25	(0.06)	23.18%	0.75	0.67	10.52	-	0.67	-	0.67	0.49	1.28	-	-
11	11.43	11.57	92.5%	11.25	0.32	37.63%	1.21	1.09	10.48	1	0.77	-	0.77	0.72	2.00	-	-
12	12.04	12.19	97.5%	11.25	0.94	47.96%	1.55	1.39	10.80	1	0.45	-	0.45	0.61	2.62	-	-
13	12.62	12.77	102.2%	11.25	1.52	57.95%	1.87	1.68	11.09	1	0.16	-	0.16	0.31	2.92	-	-
14	12.85	13.01	104.1%	11.25	1.76	61.47%	1.98	1.78	11.23	1	0.02	-	0.02	0.09	3.01	-	-
15	13.03	13.19	105.6%	11.25	1.94	62.78%	2.03	1.82	11.37	1	(0.12)	0.12	-	0.01	3.02	0.06	0.06
16	13.20	13.37	106.9%	11.25	2.12	59.55%	1.92	1.73	11.64	1	(0.39)	0.39	-	-	3.02	0.26	0.32
17	13.33	13.50	108.0%	11.25	2.25	46.69%	1.51	1.36	12.14	1	(0.89)	0.89	-	-	3.02	0.64	0.96
18	12.78	12.94	103.5%	11.25	1.69	24.24%	0.78	0.70	12.24	1	(0.99)	0.99	-	-	3.02	0.94	1.90
19	12.28	12.43	99.4%	11.25	1.18	5.47%	0.18	0.16	12.27	1	(1.02)	1.02	-	-	3.02	1.00	2.90
20	11.39	11.53	92.2%	11.25	0.28	0.00%	-	-	11.53	1	(0.28)	0.28	-	-	3.02	0.65	3.55
21	10.91	11.05	88.4%	11.25	(0.20)	0.00%	-	-	11.05	-	-	-	-	-	3.02	0.14	3.69
22	9.74	9.86	78.9%	11.25	(1.39)	0.00%	-	-	9.86	-	-	-	-	-	3.02	-	3.69
23	9.02	9.14	73.1%	11.25	(2.11)	0.00%	-	-	9.14	-	-	-	-	-	3.02	-	3.69


Solar Alternative
Facility Load (MW)
15.00
14.00
13.00
12.00
11.00
10.00
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		2.25	DER MWac
Safety Margin for Projected Size and Resulting DER MWac (Default is 10%)	10%	2.48	DER MWac
DER MWac based on Projected Load Estimate and the Average Solar Output for July & August	62.78%	3.94	DER MWac
Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 1.1)	0.9	3.55	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	26.97	acres

3) Cost Estimate

Solar PV Costs	$/MWdc		
Cost of Solar PV array (default $2M / MWdc)	$ 2,000,000	$ 7,096,278	$
Lands Costs	$/acre		
Lands acquisition costs	$ 5,000	$ 134,829	$
Interconnection Costs:			
Substation Costs			
Feeder Breaker Addition	$ -		$
SCADA/Telecom	$ 800,000		$
Subtotal		$ 800,000	$
Distribution Feeder Costs			
New feeder	$ -		$
Feeder extension	$ 300,000		$
Metering	$ 80,000		$
Subtotal		$ 380,000	$
Summary Cost Estimate for Solar Alternative		$ 8,411,108	$ Total

Energy Storage Only Alternative

1) Is battery storage a feasible alternative? Yes

Provide a brief description if not feasible:

2) Determine Battery requirements:

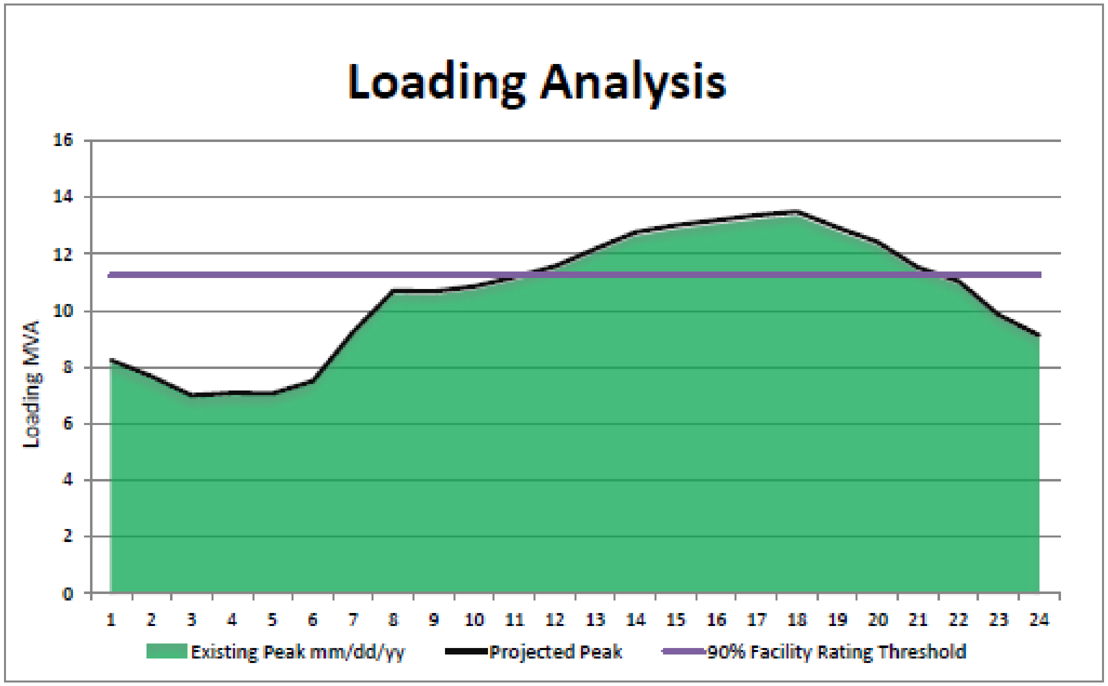
Forecasted Growth %:	**1%**	Value from the Summary tab
Loading Constraint (MVA):	**13.50**	Value from the Summary tab
Target Facility Loading w/ DER:	**11.25**	Value from the Summary tab

Time	Existing Peak mm/dd/yy	Projected Peak	Need for DER (MVA)	MVAHrs Needed	90% Facility Rating Threshold
0	8.15	8.25	-3.00	-3.29	11.25
1	7.57	7.67	-3.58	-3.92	11.25
2	6.91	7.00	-4.25	-4.21	11.25
3	7.00	7.09	-4.16	-4.17	11.25
4	6.99	7.08	-4.17	-3.96	11.25
5	7.42	7.51	-3.74	-2.86	11.25
6	9.15	9.26	-1.99	-1.27	11.25
7	10.58	10.71	-0.54	-0.56	11.25
8	10.55	10.68	-0.57	-0.48	11.25
9	10.73	10.86	-0.39	-0.22	11.25
10	11.05	11.19	-0.06	0.13	11.25
11	11.43	11.57	0.32	0.63	11.25
12	12.04	12.19	0.94	1.23	11.25
13	12.62	12.77	1.52	1.64	11.25
14	12.85	13.01	1.76	1.85	11.25
15	13.03	13.19	1.94	2.03	11.25
16	13.20	13.37	2.12	2.18	11.25
17	13.33	13.50	2.25	1.97	11.25
18	12.78	12.94	1.69	1.43	11.25
19	12.28	12.43	1.18	0.73	11.25
20	11.39	11.53	0.28	0.04	11.25
21	10.91	11.05	-0.20	-0.80	11.25
22	9.74	9.86	-1.39	-1.75	11.25
23	9.02	9.14	-2.11	-1.06	11.25

	MVA	MVAHrs	Duration(hrs)
Battery Requirement:	3.00	14.00	5

Sufficient Charging Time? YES

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



3) Determine cost of the battery storage system

	Estimate $
Battery System	$10,600,000
Civil Work	$560,000
Property Cost	$1,286
Distribution Costs	$300,000
Substation Costs	$800,000
Maintenance Contract (10 yrs)	$510,000
Total	$12,771,286

Cost Table - Derived from PAC Estimating Tool

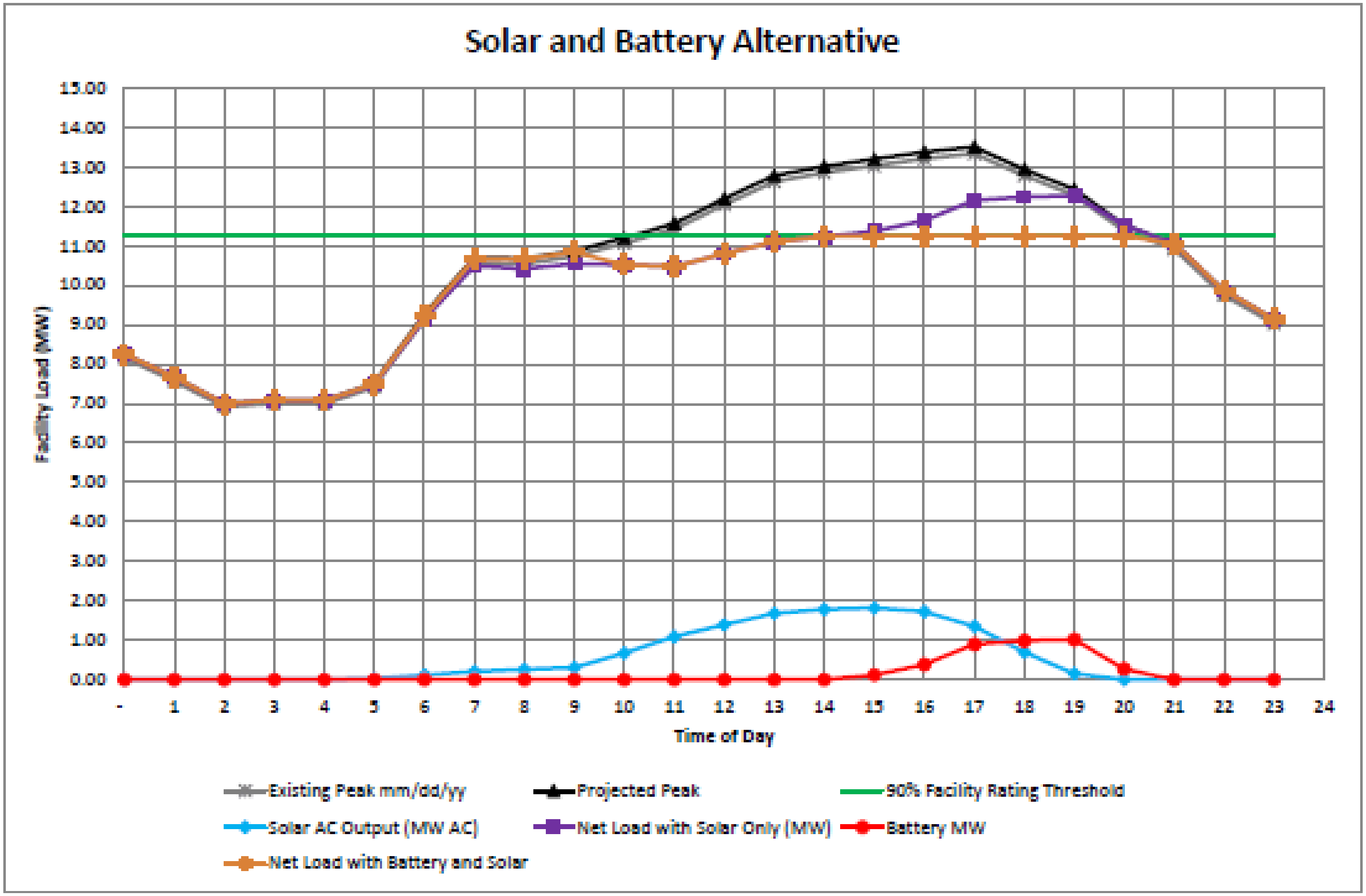
Duration (hrs)	Power Rating (MVA) 1	2	3	4	5
1	1.4	2.4	3.4	4.4	5.4
2	2	3.6	5.2	6.8	8.4
3	2.6	4.8	7	9.2	11.4
4	3.2	6	8.8	11.6	14.4
5	3.8	7.2	10.6	14	17.4
6	4.4	8.4	12.4	16.4	20.4
7	5	9.6	14.2	18.8	23.4
8	5.5	10.7	16	21.2	26.4

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		Solar Information		Battery Information	
% Increase from Existing Peak to Projected Peak	1.2%	2.25	= Minimum DER MWac Output based on Projected Peak that equals or exceeds Planning Criteria	Discharge Eff: 0.95	Charge Eff: 0.95 = Default Efficiencies
		0.9	= Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 0.9)	Battery MW: 2.00	Battery Duration Hrs: 2

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
	Max	Max				Max	Min Solar Size (MW)								Sum		Sum	Battery MWh			
	13.33	13.50	12.50			62.76%	3.23								3.02		3.69	4.00	4.10		
-	8.15	8.25	66.0%	11.25	(3.00)	0.00%	-	-	8.25	-	-	-	-	-	-	-	-	-	-	8.25	-
1	7.57	7.67	61.3%	11.25	(3.58)	0.00%	-	-	7.67	-	-	-	-	-	-	-	-	-	-	7.67	-
2	6.91	7.00	56.0%	11.25	(4.25)	0.00%	-	-	7.00	-	-	-	-	-	-	-	-	-	-	7.00	-
3	7.00	7.09	56.7%	11.25	(4.16)	0.00%	-	-	7.09	-	-	-	-	-	-	-	-	-	-	7.09	-
4	6.99	7.08	56.6%	11.25	(4.17)	0.00%	-	-	7.08	-	-	-	-	-	-	-	-	-	-	7.08	-
5	7.42	7.51	60.1%	11.25	(3.74)	1.05%	0.03	0.03	7.48	-	0.03	-	0.03	0.02	0.02	-	-	-	-	7.50	0.02
6	9.15	9.26	74.1%	11.25	(1.99)	4.25%	0.14	0.12	9.14	-	0.12	-	0.12	0.08	0.09	-	-	-	-	9.21	0.09
7	10.58	10.71	85.7%	11.25	(0.54)	7.34%	0.24	0.21	10.49	-	0.21	-	0.21	0.17	0.26	-	-	-	-	10.66	0.26
8	10.55	10.68	85.4%	11.25	(0.57)	9.13%	0.29	0.27	10.41	-	0.27	-	0.27	0.24	0.50	-	-	-	-	10.65	0.50
9	10.73	10.86	86.9%	11.25	(0.39)	10.74%	0.35	0.31	10.55	-	0.31	-	0.31	0.29	0.79	-	-	-	-	10.84	0.79
10	11.05	11.19	89.5%	11.25	(0.06)	23.18%	0.75	0.67	10.52	-	0.67	-	0.67	0.49	1.28	-	-	-	-	10.52	
11	11.43	11.57	92.5%	11.25	0.32	37.63%	1.21	1.09	10.48	1	0.77	-	0.77	0.72	2.00	-	-	-	-	10.48	
12	12.04	12.19	97.5%	11.25	0.94	47.96%	1.55	1.39	10.80	1	0.45	-	0.45	0.61	2.62	-	-	-	-	10.80	
13	12.62	12.77	102.2%	11.25	1.52	57.95%	1.87	1.68	11.09	1	0.16	-	0.16	0.31	2.92	-	-	-	-	11.09	
14	12.85	13.01	104.1%	11.25	1.76	61.47%	1.98	1.78	11.23	1	0.02	-	0.02	0.09	3.01	-	-	-	-	11.23	
15	13.03	13.19	105.6%	11.25	1.94	62.76%	2.03	1.82	11.37	1	(0.12)	0.12	-	0.01	3.02	0.06	0.06	0.06	0.07	11.25	
16	13.20	13.37	106.9%	11.25	2.12	59.55%	1.92	1.73	11.64	1	(0.39)	0.39	-	-	3.02	0.26	0.32	0.33	0.35	11.25	
17	13.33	13.50	108.0%	11.25	2.25	46.69%	1.51	1.36	12.14	1	(0.89)	0.89	-	-	3.02	0.64	0.96	1.01	1.06	11.25	
18	12.78	12.94	103.5%	11.25	1.69	24.24%	0.78	0.70	12.24	1	(0.99)	0.99	-	-	3.02	0.94	1.90	2.00	2.10	11.25	
19	12.28	12.43	99.4%	11.25	1.18	5.47%	0.18	0.16	12.27	1	(1.02)	1.02	-	-	3.02	1.00	2.90	3.06	3.22	11.25	
20	11.39	11.53	92.2%	11.25	0.28	0.00%	-	-	11.53	1	(0.28)	0.28	-	-	3.02	0.65	3.55	3.74	3.93	11.25	
21	10.91	11.05	88.4%	11.25	(0.20)	0.00%	-	-	11.05	-	-	-	-	-	3.02	0.14	3.69	3.88	4.09	11.05	
22	9.74	9.86	78.9%	11.25	(1.39)	0.00%	-	-	9.86	-	-	-	-	-	3.02	-	3.69	3.88	4.09	9.86	
23	9.02	9.14	73.1%	11.25	(2.11)	0.00%	-	-	9.14	-	-	-	-	-	3.02	-	3.69	3.88	4.09	9.14	
																	3.70	3.90	4.10	Rounded to tenths place	
																	4.00	4.00	5.00	Rounded to ones place	


Solar and Battery Alternative
Facility Load (MW)
15.00
14.00
13.00
12.00
11.00
10.00
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		2.25	DER MWac
Safety Margin for Projected Size and Resulting DER MWac (Default is 10%)	10%	2.48	DER MWac
DER MWac based on Projected Load Estimate and the Average Solar Output for July & August	62.78%	3.94	DER MWac
Ratio Assumption for DC Solar Panels to AC Inverter Output Needed (Default is 1.1)	0.9	3.55	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	26.97	acres

3) Solar Cost Estimate

Solar PV Costs	$/MWdc		
Cost of Solar PV array (default $2M / MWdc)	$ 2,000,000	$ 7,096,278	$
Land Costs	$/acre		
Land acquisition costs	$ 5,000	$ 134,829	$
Interconnection Costs:			
Substation Costs			
Feeder Breaker Addition	$ -		$
SCADA/Telecom	$ 800,000		$
Subtotal		$ 800,000	$
Distribution Feeder Costs			
New feeder	$ -		$
Feeder extension	$ 300,000		$
Metering	$ 80,000		$
Subtotal		$ 380,000	$
Summary Cost Estimate for Solar Portion of Alternative		$ 8,411,108	$ Subtotal

PacifiCorp

Demand Side Management
Direct Load Control

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 cumulative (MVA)	0.38	0.17	0.34	0.51	0.69	0.87	1.05	1.23	1.41	1.60

Winter or Summer Peaking:	Summer
State:	Oregon
# of Customers Impacted:	2768

\# Customers Impacted By Class

Industrial	Commercial	Residential	Irrigation	
2	15	2741	10	2768

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	65.33	0.29	0.05	1.11
kw available	130.65	4.40	140.39	11.13
cost per kw	$76.00	$76.00	$152.00	$71.00
Cost for impacted	$9,929.65	$334.65	$21,339.48	$789.96

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.

287 Total kW Available

$32,394 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
Washington	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
Washington	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	
Washington	$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	
Washington	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 F – Distribution Substation Metering Technical Requirements

1) All installations will be engineered, prints issued, and as-built 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 based 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.

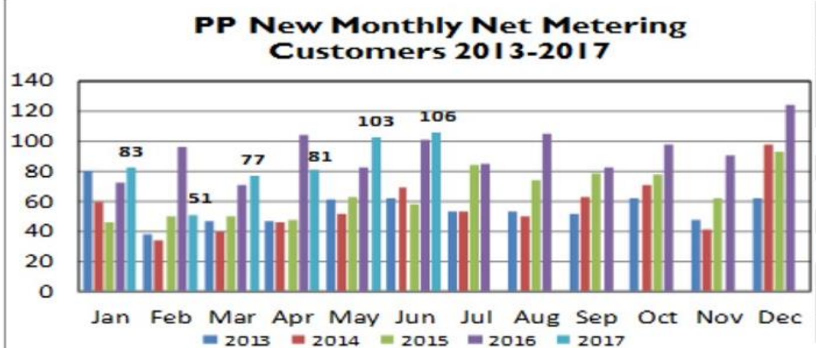
Appendix G – Pacific Power Net Metering and Customer Generation

Monthly net metering and customer generation report for June of 2017:

PACIFIC POWER
A DIVISION OF PACIFICORP

Private Generation Interconnected Facilities as of June 2017

Pacific Power enrollment increased by 106 customers, with 72 from Oregon, 29 from Washington, and five from California.



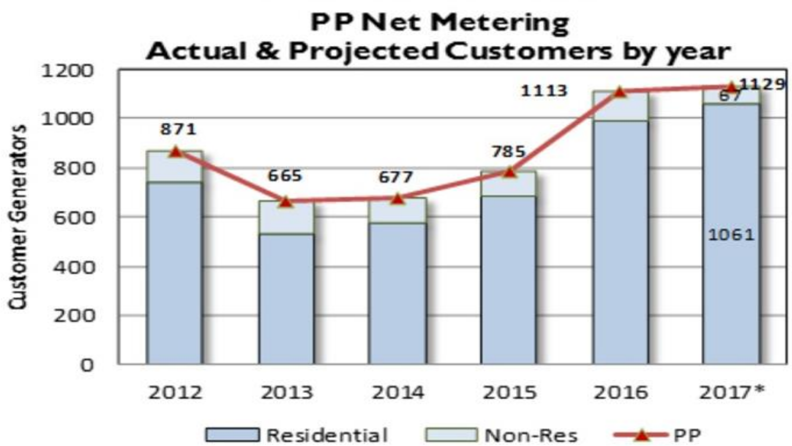
PP Cumulative Totals

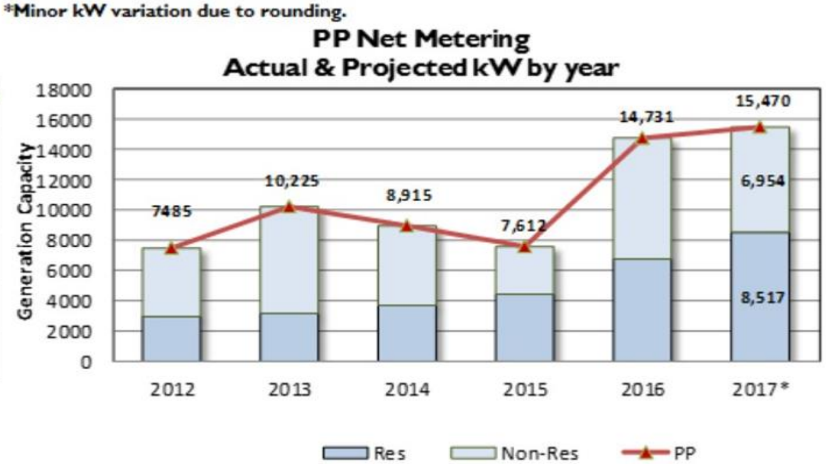
As of July 12, 2017

State	Total Customers	Residential Customers	Non-Res Customers	Residential Size (kW)*	Non-Res Size (kW)*	Total Generation (kW)*
CA	343	293	50	2,208	3,792	6,000
OR	5,676	4,849	827	23,506	30,850	54,356
WA	735	649	86	5,482	2,364	7,846
PP	**6,754**	**5,791**	**963**	**31,197**	**37,006**	**68,202**

Average Size of Residential System	5.4 kW
Average Size of Non-Residential System	38.4 kW

***Minor kW variation due to rounding.**





***2017 customer and KW projections based on a historical three month rolling average and does not consider current private generation initiatives.**
****All kW reported is at the DC rating.**

Appendix H – TOU Rates Participation by State

PacifiCorp has included an update to time based rates schedule participation by state in Table 11.

Table 11 Time-Based Rate Schedule Participation by State

Description	State	Schedule	Participating Customers (April 26th, 2017)	Eligible Customers	Participating Eligible Customers	Voluntary or Mandatory
Residential TOU Pricing	Idaho	36	12,334	61,506	20.05%	Voluntary
	Oregon	4/210	1,132	492,495	0.23%	Voluntary
	Utah	2	446	770,948	0.06%	Voluntary
General Service(*Business Sector and Irrigation*) TOU Pricing, Either Energy or Demand	California	PA-115	24	25	96%	Voluntary (Pilot)
	California	AT48	19	19	100%	Mandatory
	Idaho	35/35A	3	10,732	0.03%	Voluntary
	Oregon	23/210	256	78,442	0.33%	Voluntary
	Oregon	41/210	59	5,591	1.06%	Voluntary

	Oregon	41/215	106	106	100%	Voluntary (Pilot)
	Oregon	47	7	7	100%	Mandatory
	Oregon	48	194	194	100%	Mandatory
	Utah	6A/6B	2,207	103,120	2.14%	Voluntary
	Utah	8	242	242	100%	Mandatory
	Utah	9/9A	169	169	100%	Mandatory
	Utah	10	241	3,188	7.56%	Voluntary
	Utah	31	8	8	100%	Mandatory
	Washington	47T	1	1	100%	Mandatory
	Washington	48T	68	68	100%	Mandatory
	Wyoming	33	11	11	100%	Mandatory
	Wyoming	46	82	82	100%	Mandatory
	Wyoming	48T	28	28	100%	Mandatory