PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 1, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Filing Center

Re: UM ____—PacifiCorp's 2013 Smart Grid Report and Motion for Protective Order

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing its 2013 Smart Grid Report in compliance with Order No. 12-158 in docket UM 1460. Attached to this cover letter is Attachment A—Requirements Index, showing which sections of the 2013 Smart Grid Report satisfy the requirements of Order No. 12-158.

In support of its report, the Company is also enclosing the following attachments:

Confidential Exhibit A—Advanced Metering Project Analysis
Confidential Exhibit B— Communicating Faulted Circuit Indicators Project Analysis
Confidential Exhibit C—Dynamic Line Rating System Analysis
Confidential Exhibit D—Smart Grid Financial Model

Confidential Attachments A through D are being provided under separate cover under OAR 860-001-0070. The Company's filing also includes a motion for protective order in this matter.

Confidential Exhibit D is being provided electronically on the enclosed confidential CD.

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

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

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

Informal questions concerning this filing may be directed to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith /AS
William R. Griffith
Vice President, Regulation

Enclosures

cc: Service List – UM 1460

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of 2013 Smart Grid Report on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 1st day of August.

Carrie Meyer
Supervisor, Regulatory Operations

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM [INSERT]

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2013 Annual Smart Grid Report.	Motion for Protective Order by PacifiCorp d/b/a Pacific Power EXPEDITED CONSIDERATION REQUESTED

Under ORCP 36(C)(7) and OAR 860-001-0080(1), PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) moves the Public Utility Commission of Oregon (Commission) for entry of a standard protective order in this proceeding. As directed in Order No. 12-158 in docket UM 1460, the Company will file its first-annual Smart Grid Report on August 1, 2013 (the Report). The Report will include confidential information related to the Company's analysis of smart grid projects and market-sensitive information related to smart grid vendors. The Company requests expedited consideration of this motion in order to facilitate parties' review of the confidential information in the August 1 filing prior to the Company's presentation at a public meeting approximately 30 days after the Report is filed, as required by Order No. 12-158. Good cause exists to issue a protective order to protect commercially sensitive and confidential business information related to the Report.

The Commission's rules authorize PacifiCorp to seek reasonable restrictions on discovery of trade secrets and other confidential business information.[1] The Commission's standard protective order is designed to allow the broadest possible discovery consistent with

[1] *See* OAR 860-001-0000(1) (adopting the Oregon Rules of Civil Procedure); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also In re Investigation into the Cost of Providing Telecommunication Service,* Docket UM 351, Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").

the need to protect confidential information.[2] PacifiCorp expects to receive discovery requests in this proceeding, including requests for propriety cost data and models, commercially sensitive pricing information, confidential market analyses and business projections, or confidential information regarding contracts for the purchase or sale of electric power, power services, or fuel. PacifiCorp will be exposed to competitive injury if it is forced to make unrestricted disclosure of its confidential business information.

It is also likely that the parties to these proceedings will seek to discover further information held by PacifiCorp, including confidential business information. Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

For these reasons, PacifiCorp respectfully requests that the Commission enter its standard protective order in this docket. The Company requests expedited consideration of this motion to allow parties who execute the protective order to obtain prompt responses to discovery requests.

Respectfully submitted this 1st day of August, 2013.

____
Etta Lockey
Counsel
PacifiCorp d/b/a Pacific Power

[2] OAR 860-001-0080(2).

ATTACHMENT A
REQUIREMENTS INDEX

Requirements Index
2013 Smart Grid Report

Docket requirements and their location in the table of contents of the report are listed below.

Report Requirements List

1) Smart-Grid Strategy, Goals and Objectives
   The utility must describe its smart-grid strategy, goals, and objectives and their alignment with state and Commission policies.
   - **Smart Grid Strategies, Objectives and Goals – pp 5-7**
2) Status of Smart-Grid Investments
   a. The utility must describe smart-grid projects, initiatives, and activities underway and the results to date.
      - **Smart Grid Projects – pp 32-43**
        - **Transmission Synchrophasor Demonstration Project**
        - **Dynamic Line Rating Projects**
        - **Conservation Voltage Reduction Pilot Project**
   b. The utility must describe smart-grid investments and applications it plans to undertake over the next five years (including pilots and testing).
      - **Smart Grid Projects – pp 32-43**
        - **Communicating Faulted Circuit Indicators**
        - **Dynamic Line Rating Projects**
3) Smart-Grid Opportunities and Constraints
   a. List and describe other smart-grid opportunities the utility is considering for investment over the next five years and any constraints that affect the utility's investment considerations
      - **Smart Grid Projects – pp 32-43**
      - **Challenges and Risks – pp 44-51**
   b. Describe evaluations and assessments of smart-grid technologies and applications that the company has undertaken or plans to undertake
      - **Economic Review – pp 52-58**
   c. List and describe smart-grid pilots and programs the utility is monitoring. Describe technology research, development and demonstrations the utility is monitoring
      - **Appendix B - Smart Grid Technologies at Other Companies – pp 63-65**
   d. Provide assessment of state of key technologies that give rise to the opportunities and constraints identified above
      - **Components of the Smart Grid pp 11-31**
4) Targeted Evaluations
   Discuss evaluation of technologies and applications pursuant to Commission-approved stakeholder recommendations
   - **Challenges and Risks – Electric Vehicle Penetration and Vehicle-to-Grid Technology – pp 49-51**

5) Related Activities
Discuss related activities to address physical- and cyber-security, privacy, customer outreach and education, and IT and communication infrastructure, as they relate to smart-grid activities.

- **Smart Grid Projects – pp 32-43**
  - **Customer Information and Demand-Side Management Enhancements**
- **Components of the Smart Grid – pp 11-32**
  - **Information and Communication Infrastructure**
- **Challenges and Risks – pp 44-51**
  - **Security**
  - **Customer Communications**
- **Economic Review – pp 52-58**
  - **Customer Education**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Smart Grid Annual Report

August 1, 2013

Table of Contents

Executive Summary

The smart grid began as a loosely defined concept but has come to refer to a variety of advanced technologies and equipment used by utilities and their customers. In general the smart grid is a system of communications networks coupled with automated control of the power grid and end-use devices, along with enhanced customer awareness of their electricity use and its impact. For PacifiCorp the smart grid definition started with a review of relevant technologies for transmission, substation and distribution systems, as well as smart metering and home area networks which enable consumer response to system inputs such as price fluctuations and load curtailment requests. A review of the interoperation of these technologies showed that the most critical infrastructure decision to be made during smart grid design is the communications network. This network must be high-speed, secure and highly reliable and must be scalable to support PacifiCorp's entire service territory. The network must accommodate both normal and emergency operation of the electrical system and be available at all times, especially during the first critical moments of a large scale disturbance to the system.

This smart grid report focuses on technologies that do not require major electrical system changes and can be readily integrated with the existing infrastructure. The technologies chosen for the study were narrowed down to advanced metering systems with demand response programs, distribution management systems and transmission synchrophasors. Technologies included in the study but not considered in the financial analysis include fully redundant ("self-healing") distribution systems, distributed energy systems (including electric vehicles) and direct load control programs.

Each of the components examined have quantifiable costs and benefits that were used to estimate the rough potential of investing in those technologies. While there are not always proven costs or savings for each of the components, qualified estimates can be used to gauge costs when there is enough theoretical data established for savings opportunities. A suitable analysis can then be built to gauge the relative potential of feasible alternatives. Many of the benefits are highly variable and dependent on external factors, especially factors that involve changes in consumer behavior, values of the forward capacity and energy markets, certain percentages of the customer base participating in dynamic pricing programs and the energy conservation achieved by those customers. All of the cost and savings data presented contain the most reliable data available at the time of publication.

The net present value of implementing a comprehensive smart grid system throughout PacifiCorp's territory is negative at this time. However, many smart grid technologies are showing promise for future improvements in the operation and management of transmission and distribution systems. Modification of consumer behavior would be central to realizing many benefits, since changes in usage and improved conservation have the potential to dramatically transform the electric industry. However, the ability to sustain any consumer behavior change remains uncertain.

In order to mitigate the costs and risks to the Company and its customers it is essential that technology leaders be identified and system interoperability and security issues be verified and resolved with national standards. PacifiCorp will continue to monitor technological advances and utility developments throughout the nation as more advanced metering and other smart grid related projects are built. This will allow for improved estimates of both costs and benefits. With large scale deployments progressing throughout the country, it is expected that the smart grid market leaders will become evident within the next few years. Demonstration projects will reveal the sustainability of large-scale rollouts and give utilities a better idea of which areas of the smart grid are best suited for implementation on their systems.

Smart Grid Strategies, Objectives and Goals

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

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

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

The Smart Grid department adheres to the foregoing strategies and maintains a knowledge database that is available for internal stakeholders' use when researching projects with potential smart grid components. The smart grid team also works with other internal departments to ensure that these strategies are being followed as projects progress.

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

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

These strategies and objectives are the tools by which the Company expects to be able to reach its long-term smart grid goals, which entail:

- <u>Increasing customer awareness and understanding of how the electric system works</u>, how electricity usage impacts and drives Company investments and operations.
- <u>Giving customers tools they can use</u> to change their electricity usage in ways that benefit themselves and society.
- <u>Optimizing PacifiCorp's electric system</u> through the application of cost-effective smart-grid technologies.

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

The Smart Grid – An Introduction

Electric utility companies are involved in an evolution of advanced sensing and communicating technologies and traditional operational practices. The technologies associated with advanced power grids are being accelerated by recent federal legislation—including the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA) and the American Recovery and Reinvestment Act of 2009 (ARRA). Traditional operational practices are being sustained by lower operating costs and effectively managed customer costs, but have come under increasing scrutiny as the interest in smart grids expands across the country.

Both the EPAct and the EISA required that all states review the text of the legislation and make a determination of whether or not to adopt the standards included within. While each of the states within PacifiCorp's service territory have elected not to adopt most of the standards a number have voiced an interest in understanding what the Company's current and future plans are for implementing smart grid technologies.

The interest in smart grid at the regulatory level has also grown due to the marketing efforts of companies positioned to take advantage of the investments funded by the ARRA legislation. Inquiries into the Company's ability to build out a smart grid or to participate with a local city or municipality on a smart grid pilot project continue to increase. The interest in smart grids within PacifiCorp's service territory will continue to grow as neighboring states and utilities expand their advanced technologies and more information becomes available.

The purpose of this document is to define the scope of smart grid for PacifiCorp, identify the technologies that would be required to meet the scope definition and examine the financial characteristics of such an investment. This document will not provide a recommendation for regulatory strategies nor include a consideration for the replacement of the current customer information systems (although it is imperative to a fully realized smart grid system that it be replaced). It is designed to provide the reader with a basic understanding of the smart grid definition and components, along with their costs and benefits. This document does not provide a detailed level of understanding or an ideological explanation of the finite details behind every technology that can be used to migrate to a smart grid throughout PacifiCorp's system. A road map for the future is presented which aligns the relative start dates for various system components in order to give the reader a better understanding of the progress required to reach a full smart grid with an aggressive schedule. The starting date and progression schedule of any smart grid effort must be driven by the fundamental economics to protect the Company and its customers' best interests.

The following definitions are presented as a fundamental baseline upon which to define PacifiCorp's smart grid. These concepts will be used to qualify components and goals of the smart grid throughout this report.

The Electric Power Research Institute (EPRI) defines the power system architecture of the future as[1]:

- A power system made up of numerous automated transmission and distribution systems, all operating in a coordinated, efficient and reliable manner;
- A power system that handles emergency conditions with 'self-healing' actions and is responsive to energy—both market and utility needs; and
- A power system that serves millions of customers and has an intelligent communications infrastructure enabling the timely, secure, and adaptable information flow needed to provide power to the evolving digital economy.

According to the Modern Grid Initiative[2], a smart grid has the following characteristics:

- "It will enable participation by consumers." Smart grid enables consumers to have access to new information, control, and options to engage in electricity markets. Consumers will be able to see what they use, when they use it, and what it costs them. This will enable them to manage their energy costs, invest in new devices and sell resources for revenue or environmental stewardship. In addition, grid operators will have new resource options that will enable them to reduce peak load and prices and improve reliability.
- "It will accommodate all generation and storage options." Smart grid will seamlessly integrate all types and sizes of electrical generation and storage systems. This will move the system from one dominated by central generation to a more decentralized model as more smaller distributed sources and plug-and-play convenience come into the system.
- "It will enable new products, services and markets." Smart grid will link buyers and sellers, support the creation of new electricity markets, and provide for consistent market operation across regions. That is, instead of the current poorly integrated, limited wholesale markets, smart grid will lead to mature, well-integrated wholesale markets and growth of new electricity markets.
- "It will provide power quality for the digital economy." The smart grid will provide utilities with the ability to better monitor, diagnose, and respond to power quality issues, thus reducing consumer losses due to poor power quality.
- "It will optimize asset utilization and operate efficiently." Smart grid will enhance asset operations by improving load data, reducing system losses, and integrating outage

[1] Electric Power Research Institute, "IntelliGrid Architecture Report: Volume 1 IntelliGrid User Guidelines and Recommendations." http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001012160 (accessed 4/12/2013)
[2] Office of Electricity Delivery and Energy Reliability, "What is the Smart Grid?" http://www.netl.doe.gov/213683B2-2064-4C08-8C52-E6E14642012E/FinalDownload/DownloadId-B7952B1BB5A91AF683C856B27E6E5D09/213683B2-2064-4C08-8C52-E6E14642012E/smartgrid/referenceshelf/factsheets/OE_DER-008_APPROVED_2009_04_15.pdf (accessed 7/31/2103)

management. It will also improve the maintenance and resource management processes. This will lead to reduced utility costs, both O&M and capital.

- “It will anticipate and respond to system disturbances.” With smart grid, the system will be able to self-heal by performing continuous self-assessment, detecting, analyzing, and responding to any disturbances, and restoring the grid components or network sections.
- “It will operate resiliently against attack and natural disaster.” Smart grid enables system-wide solutions to physical and cyber security issues, thereby reducing threats and vulnerabilities.

Regulatory Framework

In August 2005, Congress passed the EPAct, in which Section 1252, entitled “Smart Metering,” laid the framework for time-based pricing for electrical energy consumption. This bill required that each regulated utility offer time-based rates and each state commission investigate DR and time-based metering. All states served by PacifiCorp have reviewed and responded to the EPAct, as required, with no significant effect on the Company’s metering systems or operational standards.

On December 19, 2007, the EISA was passed and ushered in a new era in the policy decisions of state regulation commissions as well as electric utility companies within their jurisdictions. The EISA is applicable to all electric utility companies, whether investor-owned, public or municipal. The policy statement contained in Section 1301 of the EISA, “Statement of Policy on Modernization of Electricity Grid,” has broad implications that will affect all utilities and their decisions regarding the deployment of automated metering, advanced metering and smart metering technologies.

Section 1301 defines the smart grid and, indirectly, smart metering. It is more inclusive than the definition of smart metering found in Section 1252 of the EPAct. Section 1301 of the EISA defines the smart grid as

> the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a smart grid:
>
> (1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
> (2) Dynamic optimization of grid operations and resources, with full cyber-security.
> (3) Deployment and integration of distributed resources and generation, including renewable resources.
> (4) Development and incorporation of DR, demand-side resources, and energy-efficiency resources.

(5) Deployment of 'smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
(6) Integration of 'smart' appliances and consumer devices.
(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
(8) Provision to consumers of timely information and control options.
(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services[3].

To meet the intent of these generally accepted definitions of a smart grid it can be deduced that intelligent electronic devices (IEDs) must be placed on every critical node of the end-to-end grid. It can also be concluded that a smart grid must have a robust, reliable, and secure communication network throughout the grid as well. Thus, to achieve a smart grid, the Company must merge the electricity generation and delivery infrastructure with the information and communication infrastructure.

[3] National Institute of Standards and Technology, "Statement of Policy on Modernization of Electricity Grid." http://www.nist.gov/smartgrid/upload/EISA-Energy-bill-110-140-TITLE-XIII.pdf (accessed 6/2/2013)

Components of the Smart Grid

PacifiCorp began defining the smart grid with a review of relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks. As the Company reviewed these technologies it recognized that the most critical infrastructure decision is the communications network selected. The network must provide robust, high speed, low latency communication for critical applications while maintaining existing characteristics that accommodate both normal and emergency operation of the electrical system. The communication network must be available at all times, including the first critical moments of a large scale disturbance to the system.

There are several broad categories within the smart grid whose benefits and functions remain relatively undefined. For example, distribution automation is made up of several functionalities that have intelligent interoperability among themselves to enable efficiency and reliability optimization of the system. Over-sizing and redundancy will be required of a system that can locate and isolate faulted conductors and automatically restore power to areas outside fault zones, as well as increase efficiency through integrated renewable and distributed generation resources, improve system balancing and actively manage power factor and line losses. A fully redundant system is required to enable the complete spectrum of distribution automation. This level of redundancy comes at a cost that will not support any economy-based decision. Therefore, fully redundant systems are not included as part of this report.

The focus for this report will remain on those technologies that are easily integrated into the existing infrastructure, i.e., technologies that do not require major electrical system changes. The technologies chosen for the study were narrowed down to those systems shown in Table 1 below. Each of these components utilizes a common information technology and communications infrastructure to gain maximum benefit through reduced duplication of facilities. Technologies included in the study but not considered in the financial analysis include fully redundant ("self-healing") distribution systems, distributed energy systems (including electric vehicles) and direct load control programs. The Company will continue to explore these technologies and will include them in future analyses when their benefits become more mainstream and quantifiable.

With the large capital investment required to enable these smart grid elements, it is essential that the market leaders be identified and system interoperability be verified. With deployments growing throughout North America, most notably including California, Texas and Ontario and a myriad of pilots enabled through the recent ARRA funding opportunities, the market leaders will become evident as the systems begin to mature over the next few years.

Technology Component
Advanced Metering System
Demand Response
Home Area Networks
Distribution Management System
Interactive Volt-Var Optimization
Conservation Voltage Reduction
Capacitor Bank Maintenance
Centralized Energy Storage
Outage Management System
Fault Detection, Isolation and Restoration
Transmission Synchrophasors

Table 1 – Studied Technology Components

Information and Communication Infrastructure

Information and communication infrastructures are the backbone of the smart grid and are critical to the success of the program[4]. The system must be robust enough to handle the amount of data generated by the AMS and the IEDs deployed throughout the electricity delivery infrastructure; in addition the system must have the intelligence to prioritize and react to the data delivered. Information related to system disturbances or outages must be given preferential handling over lower priority items such as meter reads. The information technology system must process the data and interpret which applications need the data and in which format. It must be able to store the data in an easily retrievable, archived format and utilize that data for historical and comparative purposes. This data can then be utilized when corrective actions are needed in order to efficiently manage the electricity delivery infrastructure.

Figure 1 illustrates the smart grid information and communications architecture that must be developed to implement the entire scope of the PacifiCorp smart grid[5].

[4]U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability**,** Recovery Act Financial Assistance Funding Opportunity Announcement, Smart Grid Investment Grant Program, DE-FOA-0000058, June 25, 2009.

[5] Transmission synchrophasors are not part of the model, since that system is best operated as a stand-alone application due to the high-speed processing and handling requirements of the data received from the phasor measurement units.

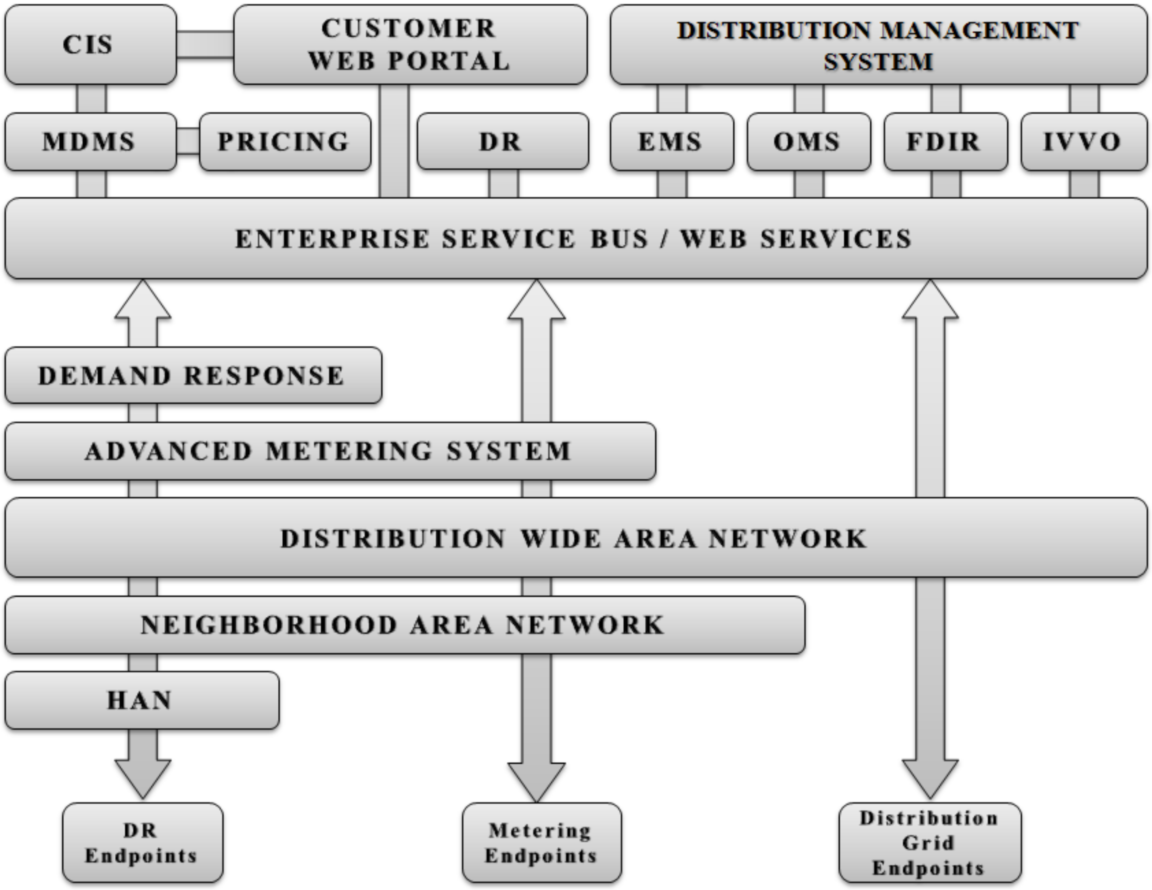

Figure 1 – PacifiCorp Smart Grid Architecture

Communications Network

A key component of a successful smart grid operation is a reliable, resilient, secure and manageable communication infrastructure. The broad scope of smart grid application areas, coupled with the large and diverse geography of PacifiCorp's service territory and low customer density, dictates an extensive, complex and ultimately costly smart grid communications network.

The purpose of a smart grid is to provide improved efficiencies in the production, transport, and delivery of energy, which can be realized in two ways:

- Better real-time control: the ability to remotely monitor and measure energy flows more closely and manage those flows in real time.

- Better predictive management: the ability to monitor the condition of different elements of the network to predict failure and direct proactive maintenance.

These mechanisms require more measurement points, remote monitoring and management capabilities than exist today. Greater reliance on reliable, robust and highly available communications is also required.

The new smart applications are dictating the need for a wider deployment of communications through the distribution circuits, all the way down to the customer premises. These functions were never envisioned for PacifiCorp's existing communication systems. New communication services must support such endpoints as AMS, automated switches, power quality devices, fault indicators and capacitor banks. At the same time, the communications network must continue to support the operational services independently of external events, such as power outages or public service provider failures, yet be economical and feasible to maintain.

As depicted in Figure 2, the smart grid communications network will leverage existing investment in the bulk transport network by reusing the existing fiber and microwave systems where possible but expanding it significantly to support other services. New wide area networks (WANs) will need to be built out or leased in order to support customer and distribution assets.

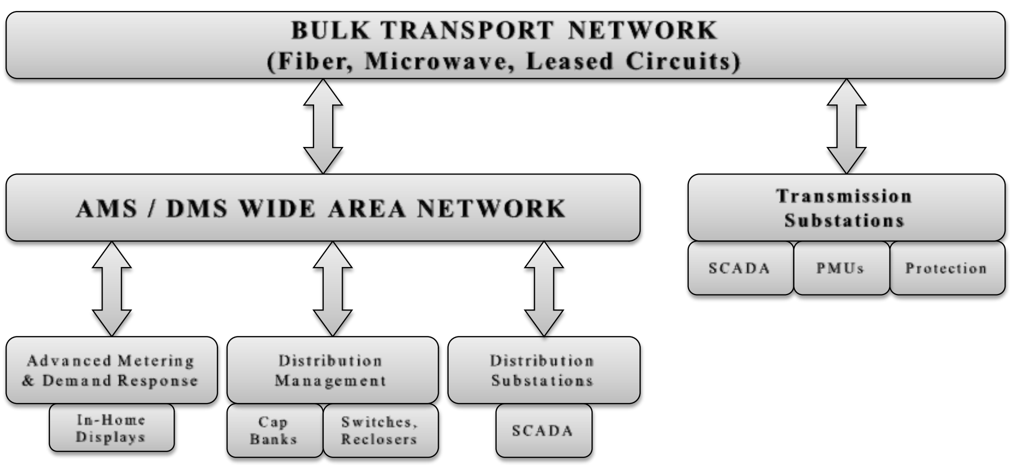

Figure 2 – Smart Grid Communications Network

The vision is to efficiently leverage the long-haul communication assets currently deployed and avoid creating silos of purpose-built networks. The key is to guarantee that the smart grid components communicate with the networks using standardized protocols. This will also help promote interoperability of different vendor components, thereby encouraging competition and lowering component and maintenance costs. One way to help achieve this is to ensure any smart grid roadmap aligns with the Smart Grid Interoperability Standards Project[6] that is being developed by the National Institute of Standards and Technology (NIST).

Advanced Metering Systems

An AMS provides the highest level of meter reading automation, satisfies all requirements for a smart grid system and provides the data required to fully integrate meter reading, DR, outage management, and distribution management functions. These systems have the capability to offer customers an in-home display of energy use related information and enable direct load control, wherein the utility sends signals to cycle specific loads (e.g. A/C, water heaters, and pool pumps). These systems are also capable of integrating indirect load control, wherein the utility sends pricing signals and consumers can program the behavior of individual appliances or adjust energy usage patterns to respond to changing prices.

Advanced metering infrastructures (AMIs) provide the same metering data levels as automated meter reading (AMR), or drive-by systems, but they provide enhanced capabilities by remotely collecting data from all meters. This functionality can be used for time-based rates and critical peak pricing programs but lacks the direct customer notification and integration of in-home displays. AMI systems can provide additional benefits in the form of outage detection and restoration messages. DR programs cannot be implemented directly through most AMI systems and must be implemented with direct load control through a separate system (such as paging) and the impacts are then measured with the AMI system. Even with their advanced functionalities AMI systems do not meet all the requirements for the smart grid.

The Federal Energy Regulatory Commission (FERC) has defined AMI as

> a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[7,8]

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[6] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0 NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0.

[7] Federal Energy Regulatory Commission. "Reports on Demand Response & Advanced Metering." http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp (accessed 3/27/2013).

Neither home area networks nor in-home displays are required components of AMI as defined by FERC, although they offer benefits for DR in addition to those made possible with AMI-supported time-varying pricing alone. Also, control of distribution equipment (reclosers, sectionalizers, capacitors, etc.) is not a required component of AMI. Combined with an AMI, these additional features begin to lay the framework for a smart grid.

AMR is typically defined as a system that only automates the manual meter reading process. These systems deliver accurate and reliable monthly meter readings to billing on a cycle basis at a cost typically lower than manual reading methods. Mobile or drive-by systems have been the most commonly implemented AMR solutions in the industry. Some AMR systems, including those installed by PacifiCorp, are capable of migrating to a one-way fixed network system that meets the basic requirements of AMI as defined by FERC[9].

The term AMI is routinely used in many discussions and papers and to support the users' own purposes for the system being proposed. AMI is used to define systems ranging from one-way fixed networks to two-way AMS. The functional requirements of the metering system must be known in order to determine the reasonableness of the system proposed. Using identifying names for the systems and not relying solely on the acronym to differentiate systems will assist in the understanding of what the metering system will deliver to the user.

For the purpose of this paper, the term "advanced metering system" will be used to maintain clarity. Advanced metering systems provide for the definition as outlined by FERC and include all the functionality required to support the smart grid. AMR systems and most AMIs cannot be migrated to an advanced metering system without significant costs.

Demand Response

One of the key requirements to encourage customers to change energy usage patterns is to send proper pricing signals. The most common price signals in the industry today are time-of-use (TOU), critical peak pricing (CPP) or critical peak rebate (CPR) programs[10]. A combination of TOU/CPP or TOU/CPR pricing programs are the most prevalent, and, designed and positioned appropriately, can present opportunities for creating reductions in energy usage during critical periods when system peaks are present.

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[8] Federal Energy Regulatory Commission, "Federal Energy Regulatory Commission Survey on Demand Response, Time-Based Rate Programs/Tariffs and Advanced Metering Infrastructure *Glossary*." http://www.ferc.gov/industries/electric/indus-act/demand-response/2008/survey/glossary.pdf (accessed 3/27/2013).

[9] Electric Power Research Institute, "Advanced Metering Infrastructure (AMI)." http://www.ferc.gov/eventcalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf (accessed 3/27/2013).

[10] SmartGrid.Gov. "Time-Based Rate Porgrams." http://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs (accessed 4/12/2013).

TOU tariffs create pricing programs that present to the consumer a proxy for real-time or relative prices of energy at various times during the day. By selling electrical energy at the real-time price it is anticipated that some consumers would shift their consumption from the peak periods, and thus higher-priced hours, to times when the cost of energy is lower. This shift in consumption will reduce the peak demand and increase the load factor on the electrical system. The most common TOU programs have on-peak and off-peak pricing components and a few also incorporate shoulder pricing.

In comparison, critical peak pricing schemes are typically included in more advanced pricing structures to encourage conservation of energy during those few hours (typically 100 hours or less) each year when electrical demand peaks and places stress on the system.

One of the unique characteristics of CPP programs is the rebound effect that occurs at the conclusion of the CPP event. This rebound effect is caused when the deferred load (primarily air conditioning in the summer months) increases dramatically at the end of the CPP event in an effort to bring customers' residences back to a "normal" comfort state. If the CPP event occurs for an extended period of time and sufficient participation occurs in shifting usage outside of the CPP event window, the rebound effect becomes more pronounced and can create a new daily system peak, potentially higher than what the normal peak may have been. This is an anomaly that can exist, but there have been insufficient studies to calculate the magnitude and overall system effect with any dependable degree of accuracy.

Given the proper pricing signals, consumers will likely reduce their peak energy usage during critical peak pricing periods. However, to date, only simple pilots of CPP pricing programs have been conducted and have provided less than meaningful statistics on the sustainability of consumer behavior change[11]. Thus, there is no history that would allow PacifiCorp to predict how much load can be reduced by and for how long customers will voluntarily participate in a dynamic pricing program.

PacifiCorp Peak Demand

The PacifiCorp summer peak of 2012 was measured at 9,831 megawatts on July 12. System daily peaks for this time period are shown in Figure 3. This historical data can be used to determine timing and pricing for future periods, although in reality the ability to forecast the exact time periods of critical peak events is not possible.

[11] http://www.smartgrid.gov/recovery_act/overview/consumer_behavior_studies

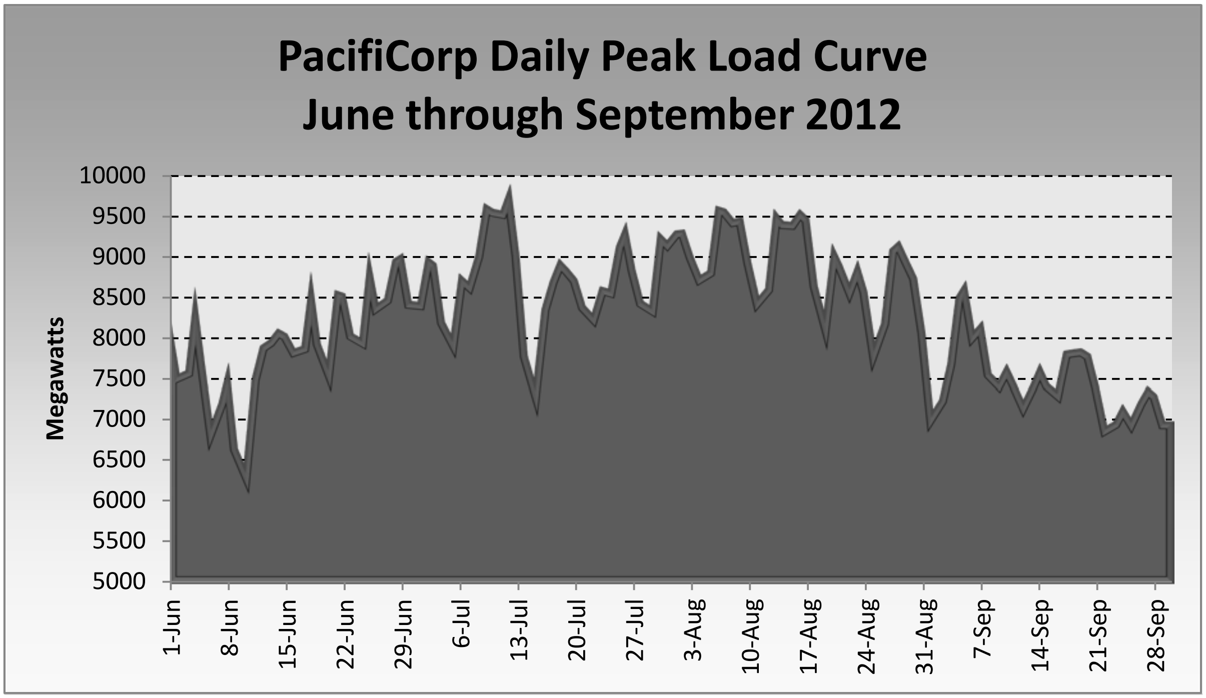

Figure 3 – PacifiCorp Daily Peak Load Curve

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s in an effort to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. These early efforts involved the management of water heating, air conditioning, and irrigation loads and laid the foundation for the air conditioning, irrigation, and business curtailment programs the Company operates today. Although participation in these programs is voluntary and relies on site-specific control equipment and communication protocols for controlling loads, as of 2012 PacifiCorp has built a control network of participating customer end use loads of over 600 megawatts.[12] The control technology and load management practices employed are some of the most advanced in the industry and, together with the Company's conservation and energy efficiency efforts, demonstrate that PacifiCorp is actively engaged in improving the efficiency and management of its system by employing education, equipment, and price incentives to optimize system performance.

In addition to direct load management programs, PacifiCorp also employs time-variant pricing schedules, both voluntary and mandatory, to assist in managing peak usage and reduce system

[12] PacifiCorp's 2013 Integrated Resource Plan, April, 2013, Chapter 5, Table 5.10 – Existing DSM Summary 2013-2022. http://eportal.pacificorp.us/irj/portal.

costs. PacifiCorp has several rate structures currently in place to help manage customer usage. These include inverted block structures for residential customers and time-of-use (TOU) and/or time-of-day (TOD) structures for residential, commercial, industrial and irrigation customers.

The residential inverted block structures increase the rate for energy as usage increases. These rates are mandatory for all customers in all of PacifiCorp's six jurisdictions. The usage block structure varies by jurisdiction with increasing prices starting at 400 kWh per month in Utah to 1,000 kWh per month in Oregon. Utah has a second price tier that starts at 1,000 kWh per month while California's incremental tier varies by season, county and whether the customer has electric heat.

The incremental price also varies by jurisdiction. In California, the highest block price is approximately 20 percent higher than the base price while in Wyoming the highest block price is more than 100 percent higher than the base price. In other jurisdictions the top block price is 30-50 percent higher than the base price. The combination of the incremental price difference and the amount of consumption in the top tier drives the overall impact of the block rate structure on usage.

Residential TOU rates have been subscribed to predominately in Idaho, with limited participation in Oregon and Utah. The TOU rates vary by season in Oregon and Idaho. In Utah the TOU rates are applicable only in the summer months.

The commercial, industrial and irrigation TOU and TOD rates are a combination of voluntary and mandatory rates depending on the jurisdiction and size of the customer, as defined by peak demand. The rates also vary in complexity. Some of the rates vary time of use, while others add a demand surcharge for on-peak use. The rates also vary by season.

The impacts of these rates were recently estimated using price elasticity metrics[13]. Price elasticity measures either the reduction in use due to an increase in price (own-price elasticity) or a shift in usage from peak to off-peak usage due to different prices at different periods (cross-price elasticity).

Table 2 is a summary of Price Schedules by State and shows current levels of participation in voluntary programs.

[13] The Cadmus Group, "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume 1." http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf (accessed 7/25/2013).

Description	State (Schedule)	Participating customers (Dec. 31, 2012)	Eligible customers (includes participating)	Percent of eligible customers participating	Voluntary/ Mandatory
Residential time-of-use or time-of-day pricing(optional)	Utah (Sch. 2)	347	714,722	0.05	Voluntary
	Oregon (Sch. 4/210)	1,229	475,853	0.26	Voluntary
	Idaho (Sch. 36)	13,994	57,931	24.16	Voluntary
General service (business sector and irrigation) time-of-use and time-of-day pricing, either energy or demand (combination of mandatory and optional)	Washington	1	1	100	Mandatory
	Washington (Sch,48T)	60	60	100	Mandatory
	California (Sch. AT48)	19	19	100	Mandatory
	Idaho (Sch. 35/35A)	4	10,023	0.04	Voluntary
	Wyoming (Sch.33)	8	8	100	Mandatory
	Wyoming (Sch.46)	80	80	100	Mandatory
	Wyoming (Sch.48T)	27	27	100	Mandatory
	Utah (Sch. 6A / 6B)	2,215	107,171	2.07	Voluntary
	Utah (Sch. 8)	268	268	100	Mandatory
	Utah (Sch. 9 / 9A)	159	159	100	Mandatory
	Utah (Sch. 10/TOD [1]	245	2,916	8.40	Voluntary
	Utah (Sch. 31)	4	4	100	Mandatory
	Oregon (Sch. 23 / 210)	274	75,157	0.36	Voluntary
	Oregon (Sch. 41 / 210)	58	6,097	0.95	Voluntary
	Oregon (Sch. 47)	7	7	100	Mandatory
	Oregon (Sch. 48)	202	202	100	Mandatory

Table 2 – Summary of Price Schedules by State

It is important to account for existing DR program loads and benefits in smart-grid business case efforts in order to avoid overestimating those benefits. The current residential air conditioning control program load reductions have been accounted for in the study; however, a detailed study of the pricing impacts in absence of this program has not been completed.

Moving from site-specific investments in DR technologies and voluntary participation to a broader system-wide deployment of information systems and price-responsive systems to drive usage patterns marks a fundamental shift in philosophy on how to manage end-use loads and engage customers.

<u>Home Area Networks (HANs)</u>

In the context of smart grid, the term “Home Area Network” has become synonymous with in-home displays and programmable communicating thermostats. Each of these devices serves a different level of functionality, enabling the consumer to have more control over their energy usage. In-home displays and HANs provide information to the consumer on which they can make operating decisions. Programmable communicating thermostats can be used for either direct load control by the electrical utility, when provided with the appropriate permissions and access by the customer, or used in a home area network scheme by the customer.

One of the key requirements to encourage customers to reduce energy usage is to make the proper pricing signals available to the consumer through either an In-Home Display (IHD) or through the HAN. IHDs range from simple plug-in and battery operated IHDs equipped with three levels of indication via green, yellow and red lights, to very sophisticated displays that interface with customers' HANs. HANs enable the customer to leverage the real-time information received via the AMS into automated actionable tasks that can reduce their energy consumption at peak times as well as enabling other forms of energy conservation. The AMS transmits key data, including usage and price signals, to the customer who can then use this information to manage and lower their consumption. To utilize the HAN, more sophisticated communicating devices are required to allow the customer to program automatic actions to pricing signals and critical peak events. HANs coupled with automated home appliances can give individuals more control over their electricity consumption.

Distribution Management System (DMS)

Greater precision in operational data and minute-by-minute management is critical to long-term success as distribution systems become more sophisticated. A DMS provides the utility with a variety of advanced analytical and operational tools for managing complex distribution systems and integrates several systems and functions that are currently operated independently, specifically:

- Outage management
- Switching operations
- Lock-out and tagging procedures
- Fault calculations
- Load flows
- Real-time state estimation routines

When integrated with an Interactive Volt-Var Optimization (IVVO) functionality the DMS can manage voltages to minimize line losses and energy needs while optimizing the delivery of power to consumers. A DMS utilizes strategically placed equipment, including distribution transformers, distribution reclosers, motor-operated switches, and fault detection devices, integrated with backbone communications as inputs to an electronic model which records and calculates key values integral to operating the system. Upon these calculations, key settings are enabled via appropriate communications paths which in turn control remote equipment which helps increase the efficiency of the system.

A DMS creates an intelligent distribution network model that provides ongoing data analysis from field-deployed IEDs to maximize the efficiency and operability of the distribution network. A complete DMS provides distribution engineers with near real-time system performance data and highly granular historical performance metrics. This decreases planning time requirements, increases visibility of the system status and improves reliability metrics through better application and management of the distribution capital budgets. A generic schematic of a smart grid DMS is shown in Figure 4.

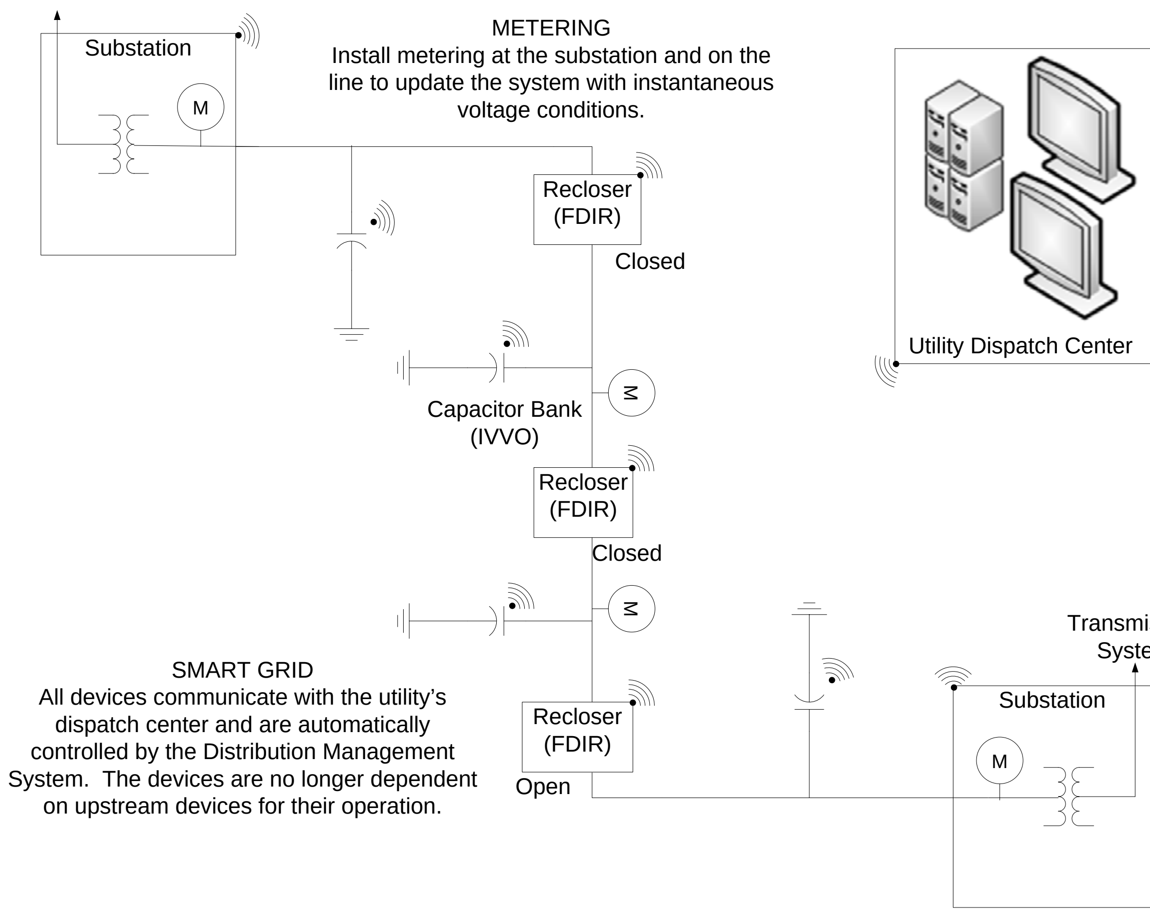

Figure 4 – Generic Distribution Management System

With appropriate data inputs from field IEDs the DMS will be able to analyze the distribution network for both normal and emergency states and perform the following functions required for IVVO and FDIR:

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

Prior to implementation of IVVO or FDIR systems as identified for PacifiCorp's smart grid, it is required that detailed network models of the distribution systems be created, including three-phase unbalanced and system connectivity models. PacifiCorp has invested in software technologies that satisfy both of these requirements, positioning itself for a functional DMS that will incorporate the emerging technologies for a smart grid.

Interactive Volt-Var Optimization (IVVO)

As established by American National Standards Institute (ANSI) Standard C84.1, allowable voltage values at the point of service under normal operating conditions include a range around a nominal value[14]. For standard residential delivery the ANSI A range voltage on a 120 volt scale spans from 114 to 126 volts (± 5 percent from nominal). For primary metered customers, the ANSI A range voltage on a 120 volt scale spans from 117 to 126 volts.

To maintain the voltage within the specified range across the entire distribution circuit the voltage at the distribution substation bus is controlled by some combination of a load tap changer (LTC), substation regulator(s) and substation capacitor(s). Features inherent in each device facilitate the utility's voltage management under all loading conditions so that acceptable voltage levels are maintained for all customers. The circuit's voltage generally degrades as a function of

[14] American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), ANSI C84.1-2011 p. 3, p. 8.

line length, impedance and loading, and, if not properly managed, can degrade to levels below the allowable ANSI limit. To keep service voltages within the allowable range, system improvements such as phase balancing, reconductoring and the addition of capacitor banks and voltage regulators are often employed. Their purpose is to ensure that the service voltage to all customers is maintained within ANSI A range under normal operating conditions.

The decision of which device to install is driven by the characteristics of the circuit at the point of application. The engineering considerations and design parameters used for this decision are complex and will not be discussed in detail other than to state that installation and operation costs, power factor, voltage levels and loading profiles must be considered.

An IVVO program utilizes strategically placed distribution voltage regulators and capacitor banks to manage voltages and power factor, as well as reduce line losses. With coordination between devices via modern firmware and communications, regulator and capacitor behavior can be adjusted to achieve such goals as: optimized voltage, optimized power factor, demand shifting or energy reduction. Operators may select the appropriate goal in real-time via a module in the DMS.

Downstream device behavior in a traditional distribution system is contingent upon upstream devices and pre-programmed operational parameters. As the penetration of distributed generation sources increases, historically adequate voltage and power factor management schemes must be updated in order to maintain satisfactory voltage levels. The DMS actively manages the voltage levels and power factor and adjusts the line devices independently to optimize the voltage profile across the distribution system. This optimized voltage profile and visibility into system behavior is only achievable through the complete integration of direct communication with the field equipment and the algorithms in the DMS. By more actively managing voltage and power factor a utility can better regulate its voltage profiles on each circuit. Real-time optimization of voltage and power factor decreases line losses across the distribution system, thereby increasing system efficiency.

Conservation Voltage Reduction (CVR)

For circuits whose load is primarily resistive (typical of residential loads), a lower distribution voltage can reduce system energy and demand. A utility that operates in the upper portion of the allowed ANSI voltage range may be able to reduce system loading and losses during select conditions by lowering its service voltages to the lower portion of ANSI Range A.

Utilities with an IVVO system already in place can achieve CVR by setting a voltage reduction priority in its DMS control module. The more efficiently a utility's circuit is designed the greater its flexibility in achieving the selected goal. A CVR module may use an AMS to obtain delivery voltage information from selected metering points along the circuit. The module then minimizes the system voltage by signaling the operation of capacitor banks and regulators according to its algorithms. This aggregate reduction in service voltage reduces load current, demand and energy.

A utility without an IVVO system can implement a simplified CVR strategy. Improvements are generally implemented to reduce primary voltage drop, correct current and voltage unbalance, meet power factor guidelines and match voltage drop behavior between multiple circuits regulated by the same device. Engineering analysis then provides the optimum device settings to achieve the lowest average delivery voltage under all operating conditions. Some metering improvements may be necessary to ensure system response meets expectations. Ongoing analysis and occasional settings adjustments may be required and visibility of system behavior towards target may be limited.

PacifiCorp has identified several potential risks of CVR and IVVO implementation, based on recent industry research and utility pilots[15]:

- Increased number of residential customer complaints due to low voltage. Examples include malfunctioning equipment, dim lights, shrunken TV screens and longer duty cycles for constant energy appliances like resistive heaters and clothes dryers.
- Increased number of commercial and industrial customer complaints due to low voltage. Examples include increased exposure of sensitive customer equipment (like computer-controlled laboratory and hospital equipment, tools and motors) to voltage sags and nuisance tripping, as well as expensive down-time affecting profitability.
- PacifiCorp's historical voltage control settings yield little room for voltage reduction, which in turn generates small energy savings relative to many other utilities where high voltage control settings have been in place.
- PacifiCorp's own cost-benefit analysis determined that only minimal improvements, such as phase balancing, are cost effective in many cases. The additional savings provided by capital improvements, such as the addition of line regulators and capacitors, most often are not cost-justified.
- Accurate measurement and verification of the energy savings achieved is problematic. Time-series voltage data at each delivery point is generally not available, so estimated delivery voltages must be used. The energy response to reduced voltage is different for each customer at any point in time. The response for any given customer also varies over time as habits and end-use appliances change. The aggregated system response must be estimated to determine the total energy savings achieved year by year. Each of these

1. [15] An Exploration of Dynamic Conservation Voltage Control, Hataway, Jacobsen and Donolo; https://www.selinc.com/WorkArea/DownloadAsset.aspx?id=99373, p. 5.

elements introduces error to the measurement and verification effort, and consideration of the total error can undermine a project's cost-effectiveness.

It is imperative that the IVVO/CVR system respond quickly to substandard voltage conditions to prevent unintended consequences and operational problems for customers' equipment. It is also critical that industry leaders arrive at a consensus for accurate, low-cost measurement and verification methods for project justification and post-implementation reporting.

Capacitor Bank Maintenance

Capacitor banks are typically visually inspected once per year for damaged tanks or blown fuses and to determine their operational state. If the capacitor bank fails or becomes inoperable between inspections, the benefits of the IVVO system and the individual capacitor banks will not be realized. An IVVO system's reporting capabilities can detect when a capacitor bank has operational problems without requiring manual inspection, which reduces the cost of annual inspection work. When a problem is detected the module can create a trouble order, thereby reducing the time the bank is out of service and maximizing the benefits of the voltage and VAR optimization routines.

Centralized Energy Storage (CES)

One of the benefits of the smart grid is the ability to integrate renewable energy sources into an electricity delivery system that is dominated by fossil fuel generation. In contrast to fossil fuel generation that is available on demand, renewable energy sources cannot be scheduled and must be considered random or variable. If a significant percentage of energy generation comes from these variable sources the grid will not be able to deliver the required power when the renewable energy source is not available. There are two primary ways to fill this generation gap without the use of fossil fuel: DR programs and CES.

CES can be used to store utility scale wind or solar generated energy (which typically occurs at non-peak hours) and release that energy during peak hours. Energy storage can also potentially benefit the transmission and distribution (T&D) system by alleviating daily congestion patterns by storing energy until the transmission system is capable of delivering it where needed. Several new technologies are currently being researched throughout the industry, including battery, pumped hydro, flywheel and compressed air energy storage. Each of these solutions has unique characteristics, benefits, applications and costs.

In contrast to the single cell rechargeable batteries used in cell phones and other small appliances, electrical battery storage for utility-scale applications require energy levels that can only be produced by converting chemical energy to electrical energy. Lithium-ion batteries have the highest power density of all advanced batteries on the commercial market. They are more common in small applications, but building large-scale lithium-ion batteries remains prohibitively expensive[16]. Flow batteries are recognized as a leading option for practical, utility-scale, high-capacity electricity storage[17]. Sodium-nickel-chloride and lithium-iron-phosphate batteries are being developed and show potential for large scale applications. For utility-scale applications, nickel-cadmium batteries have gained a reputation as a rugged, durable stored energy source with good cycling capability and a broad discharge range[18]. Some cutting-edge solutions aggregate a multitude of small batteries, such as those found in electric vehicles and uninterruptible power supplies.

Electrical battery storage provides the quickest response to energy demands. Batteries have the ability to store electrical energy generated by renewable resources, usually during off-peak times, and then release that energy when required during on-peak times. When strategically located, these battery storage solutions can also be used to delay upgrades in substation power transformers, which overload only during short periods and at peak hours of the year. For the purposes of PacifiCorp's smart grid study, battery storage is used for the centralized energy storage cost and benefit analysis.

PacifiCorp analyzed various CES systems to study their effectiveness in improving asset utilization as well as T&D upgrade deferral. It was found that a single substation storage device is beneficial to provide incremental capacity to defer a minimal investment in substation equipment. For a significant T&D upgrade deferral, multiple substation storage devices in a single or multiple substations would be required. Further, CES devices do not provide any benefit to reduce future circuit infrastructure. On the other hand, localized energy storage technology (in which storage units are placed downstream from substations) provides the most benefit in avoided future infrastructure. However, in coordination with PacifiCorp's current subdivision design standards which are designed for the most effective and efficient operation of the distribution system, the commercially available localized energy storage devices would be

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[16] International Energy Agency-Energy Technology Systems Analysis Programme and the International Renewable Energy Agency, "Electricity Storage Technology Brief." IEA-ETSAP and IRENA Technology Policy Brief E18 – April 2012 (accessed 4/12/2013).

[17] HDR Engineering, Inc., "Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System."
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/Report_Energy-Storage-Screening-Study2012.pdf (accessed 7/10/2013); *see also*
U.S. Department of Energy, "Vanadium Redox Flow Batteries." http://energy.gov/F1888222-B0BE-49E0-8123-7EFF588372B4/FinalDownload/DownloadId-E6BF686D0BB5889E80515246D5C2E030/F1888222-B0BE-49E0-8123-7EFF588372B4/sites/prod/files/VRB.pdf (accessed 4/15/2013).

[18] Linden and Reddy, "Product Engineering Processes – Battery Primer."
http://web.mit.edu/2.009/www/resources/mediaAndArticles/batteriesPrimer.pdf; *see also*
ABB, "World's Largest Battery Energy Storage System."
http://www05.abb.com/global/scot/scot232.nsf/veritydisplay/3c4e15816e4a7bf1c12578d100500565/$file/case_note_bess_gvea_fairbanks-web.pdf (accessed 4/15/2013).

heavily underutilized due to their limited kW size. Also, increased losses from additional distribution transformers, increases in capital infrastructure cost per subdivision, as well as cold load pickup are issues that would need further detailed evaluation.

PacifiCorp, in collaboration with EMB Energy Inc., worked towards testing and integration of a flywheel energy storage technology for electric power systems. The proprietary flywheel design developed by the EMB team in collaboration with Lawrence Livermore National Laboratory was expected to drive down the unit price of flywheel-based electrical storage. However, EMB Energy was unable to maintain financial stability and eventually lost its investors. Due to these reasons and prolonged delays in providing the expected results, PacifiCorp has decided to terminate its involvement in the project.

Outage Management System (OMS)

All electrical distribution systems are subject to faults caused by storms and other external events as well as failures related to aging and overloaded systems. When these faults and failures occur, protective devices such as circuit breakers, reclosers, sectionalizers and fuses operate to limit the resultant outage to the smallest practicable area. Information on the outage is currently obtained through SCADA systems, where available, and/or notifications to the Company's customer service call centers. These notifications, when interfaced with the Company's connectivity model, inform the Company that an outage exists and allows for the dispatch of personnel to manually identify the location and restore service to areas outside the fault zone. When appropriate amounts of data are received from customers, intelligence within the current outage management software can make assumptions as to where a fault may have occurred.

To accelerate service restoration times, the integration of IEDs in distribution line equipment (specifically reclosers, sectionalizers and faulted circuit indicators) provides the outage management system with intelligence that can be used to isolate the faulted sections of the system in reduced timeframes.

Fault Detection, Isolation and Restoration (FDIR)

An FDIR program utilizes strategically placed distribution reclosers, motor operated switches and fault detection devices to automate restoration. These systems enable the utility to remotely or automatically reconfigure the distribution network in response to an unplanned or planned outage. The program works by adding communication to existing reclosers, motor-operated switches and fault detection devices. The devices then communicate their status back to the DMS which tries to determine the fault location and then uses feeder ties to automate restoration to areas outside the fault zone where adjacent circuit capacity exists. The DMS then sends out a signal to open or close fault isolation devices and switches to restore the maximum number of customers. The switching is typically done within one to two minutes.

Once all automated restoration switching has been completed, the DMS can notify the distribution dispatch center of the faulted zone. The dispatch center can then send crews to identify the cause of the outage and make the repairs. By knowing the location of the faulted zone, the time related to line patrolling is reduced, thus reducing the outage time.

FDIR has been tested and used in niche applications within the electric industry for over ten years[19]. In the context of the smart grid, the distribution system will need to adapt to optimally serve and restore customers by using non-traditional feeder routes. Since sectionalizers do not have automated restoration abilities they will need to be replaced by reclosers. FDIR has traditionally been referred to as distribution automation and PacifiCorp has implemented a couple of projects using this technology. Modernizing PacifiCorp's distribution grid with FDIR technology would require a significant investment, the benefits of which cannot be guaranteed at this point in time. The evolution of architecture options and technology choices in the area of FDIR has not yet matured and it is in the best interest of the company and its customers to monitor the developments in this technological space.

Transmission Synchrophasors (TSP)

The existing PacifiCorp transmission system relies on many electronic elements to ensure reliability and to maximize the transmission capacity available on individual lines and transmission paths, including remedial action schemes and high speed digital relays. The NERC glossary defines a Special Protection System (SPS) as:

> "An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme (RAS)." [20]

PacifiCorp uses the term "Remedial Action Scheme" (RAS) and will continue with that terminology throughout this report.

[19] Serna, Camilo, "Fault Detection, Isolation and Restoration at Northeast Utilities." http://www.smartgridupdate.com/distributionautomation/pdf/Camilo-Serna.pdf (accessed 7/31/2013).

[20] North American Electric Reliability Corporation, "Glossary of Terms Used in NERC Reliability Standards." http://www.nerc.com/files/Glossary_of_Terms.pdf (accessed 7/31/2013).

RAS have become more widely used in recent years to provide protection for power systems against problems not directly involving specific equipment fault protection. RAS, along with high speed digital relays, are the latest technologies used to maximize the operational efficiency of the transmission system. RAS are designed to monitor and protect electrical systems by automatically performing switching operations in response to adverse network conditions to ensure the integrity of the electrical system and avoid network collapse. RAS use a combination of programmable logic controllers and high speed digital relays to provide this protection. For example, the sudden loss of one transmission line may require dropping a generator's output to prevent the overloading of an adjacent and parallel transmission line. Without the RAS, the parallel line would become overloaded in a short period of time and trip itself offline to be protected from damage. Without the RAS a cascading outage might be hard to avoid.

Transmission smart grid is generally synonymous with the phase measurement unit (PMU, or synchrophasor) and the communication network which links many PMUs to a central processor. The PMU is the building block of transmission system smart grid applications. The intelligent use of PMU data can lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement[21]. The PMU can also be used to increase reliability by synchrophasor-assisted protection due to line condition data being relayed faster through the communication network. Future applications of this precise data could be developed to dynamically rate transmission line capacity, real time and real condition line/path ratings, and real time power factor optimization. Such dynamic ratings would require vast changes in the current contract path (a transmission owner's rights to sell capacity are based on contracts, not actual flows) transmission capacity methodology currently employed by PacifiCorp and other transmission operators in the Western Electric Coordinating Council. PMU implementation and further development may enable transmission operators to integrate variable resources and energy storage more effectively into their balancing areas and minimize service disruptions. A self-healing transmission grid would reduce outages by "detouring" energy to other paths with available capacity.

Several suppliers offer PMU units that can be used today. In fact, this technology has been around since 1979, according to General Electric[22]. PMU deployment is dependent on a WAN of sufficient geographical coverage, bandwidth, reliability, security and latency to enable PMU functions. Specific data processing and decision logic are required for operations.

[21] U.S. Energy Information Agency, "New technology can improve electric power system efficiency and reliability." http://www.eia.gov/todayinenergy/detail.cfm?id=5630 (accessed 4/12/2013).
[22] Adamiak, Mark, General Electric. "Synchrophasors… in the beginning." http://www.pacw.org/issue/autumn_2007_issue/synchrophasors/synchrophasorsin_the_beginning.html (accessed 7/31/2103).

A WAN constructed to support a network of PMU devices would enable distribution improvements at transmission-distribution interface substations. These substations can serve as the common communication and data-gathering node for both transmission and distribution data and control. The General Electric topology model envisions a PMU, a micro-grid coordinator, and substation operations logic co-located at the substation.

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

Technology Dependency

Many of the technologies required to migrate the existing electrical system to a full smart grid are dependent upon preceding technology deployment. To gain the full benefit of the individual technologies it is necessary that all interdependent and preceding technologies are fully integrated. The information and communications technologies are required for all smart grid applications and cannot be excluded from any program analysis. For instance, to gain the full benefit of IVVO the distribution management system must be developed and integrated into the information and communications systems prior to field deployment of the smart-grid enabled capacitors and line regulators.

Figure 5 illustrates the technology dependencies for the PacifiCorp smart grid. The illustration shows that a functional smart grid must be built from the top down and along the paths indicated. The only exception to this requirement is the transmission synchrophasor system, which is being built out independently of the other systems.

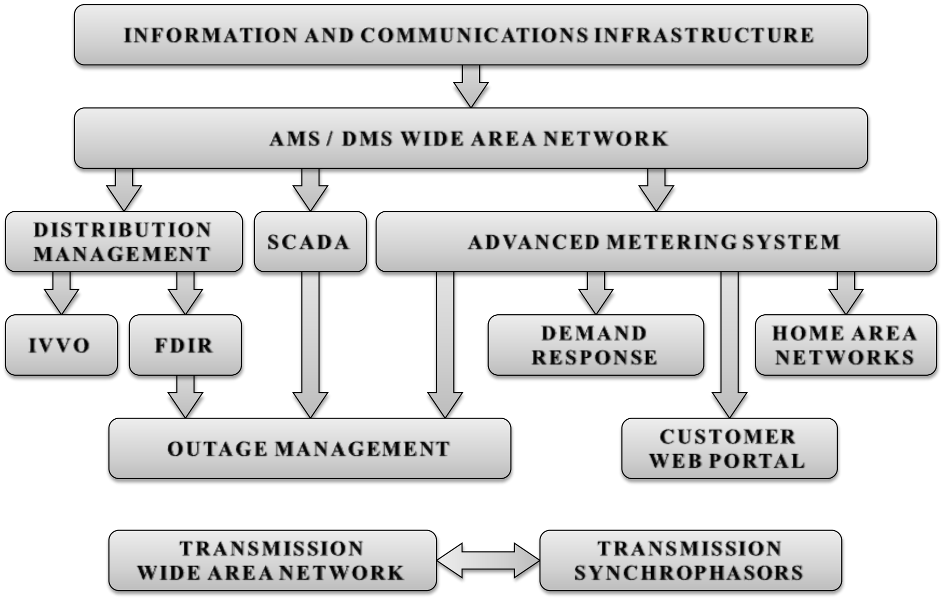

Figure 5 – Smart Grid Technology Dependencies

Smart Grid Projects

PacifiCorp is implementing a number of smart-grid related projects, with additional potential projects currently in research and planning phases. Projects are chosen in conjunction with smart grid strategies as well as on their merit as investments that cost-effectively improve service to the Company's customers while evolving critical infrastructure.

This section describes smart grid projects in the metering, transmission, substation and distribution environments, along with demand-side management investments and customer-based programs.

Oregon Advanced Metering Project

Overview

The metering industry has experienced significant evolution over the last decade and more change is expected as technologies improve and project details are circulated. Some utilities have opted to move away from purely electromechanical meters and implement automated meter reading (AMR, also known as "drive-by") solutions as cost-saving and safety improving measures. A number of other utilities have moved directly to a fully integrated smart meter solution, or advanced metering infrastructure (AMI). To date, PacifiCorp has implemented drive-by, one-way communication AMR solutions in Washington, Utah, and Wyoming. These projects have succeeded in reducing meter reading costs, improving the quality of service to customers and improving employee safety.

In February 2012 an effort was initiated to find a financially viable two-way AMI solution in Oregon, driven by the Oregon Commission's interest in a two-way advanced metering system as opposed to an AMR solution. Company analysis of existing AMI systems at that time had proven to be financially unviable and technically unproven in a coverage territory as large and low density as PacifiCorp's.

Analysis

After industry research and discussions with major meter manufacturers, PacifiCorp was introduced to a solution with the capability to migrate over time from a one-way automated metering system to a two-way advanced metering system, potentially enabling the Company to gain the benefits of both systems while avoiding the risk of a stranded meter investment. This would allow an advanced meter solution to be implemented in two phases, following a schedule determined by key indicators. The Phase 1 meter system would operate as a normal one-way automated meter reading system, as PacifiCorp utilizes today in three states, while costs associated with the communications network and related software of an advanced two-way system would be deferred to a future date when the Phase 2 two-way system is determined to be financially feasible.

Completed and Future Actions

The Smart Grid department, along with Metering, Operations and other internal stakeholder departments, are exploring potential strategic approaches to the implementation of a migratory solution, as well as investigating the potential for a full AMI system in Oregon.

Timeline

As the first step in this project, it is recommended that the Company develop an advanced metering system strategy that addresses not only metering requirements and the delivery of associated cost savings, but also allows for evolving technologies to further mature. This will ensure that a decision involving all impacted departments can be fully vetted and sequencing with other PacifiCorp technology projects (e.g. replacing the customer service and support system) can be achieved. The joint strategy effort will be led by the Smart Grid department and include the following departments: Metering, Transmission and Distribution operations, Information Technology, Engineering, Demand Side Management, and Telecommunications. The research and analysis work began in early 2013 and a strategy will be delivered by October, 2014.

Transmission Synchrophasor Demonstration Project

Overview

PacifiCorp is participating in the Western Electricity Coordinating Council (WECC) Western Interconnection Synchrophasor Project (WISP)[23], which includes matching funding under the Smart Grid Investment Grant (SGIG) of 50 percent. WISP is a collaborative effort between partners throughout the U.S. portion of the Western Interconnection.

PacifiCorp has committed funding to engage in planning, design, engineering and operational activities to identify and deploy synchrophasor technology at the most effective locations on PacifiCorp's system to the benefit of customers and the WECC region.

Analysis

The goal of the WISP program is to increase the coverage of phasor measurement units (PMUs) throughout the west, implement a new secure, stable, high performance WAN, and deploy enhanced situational awareness applications, tools and processes and to identify the benefits of the technology. Synchrophasor data and supporting technologies will be used by WECC and entity partners to identify and analyze system vulnerabilities and disturbances on the western bulk electric system and take timely actions to avoid wide-spread system blackouts. The system

[23] Western Electricity Coordinating Council, "The Western Interconnection Synchrophasor Program." http://www.wecc.biz/awareness/pages/wisp.aspx (accessed 4/15/2013).

will provide WECC Reliability Coordinators (RC) and Grid Operators in the Western Interconnection with the network, infrastructure, tools and applications necessary to leverage phasor measurement technology in the planning, analysis, operation and monitoring of the grid with the primary goal of improved reliability.

Completed and Future Actions

PacifiCorp currently has three substations, Jim Bridger (Wyoming), Wyodak (Wyoming) and Camp Williams (Utah) that have PMUs installed and streaming data to WECC via two phasor data concentrators (PDCs) installed in a company facility in Salt Lake City. The PDCs collect and archive real time data streams from remote substation site PMUs and transmit the real time data to WECC in Vancouver, Washington. Two additional substations, Populus (Utah) and Mona (Utah), have PMUs installed and are expected to have data streaming to WECC by the end of August, 2013.

The installations of the first five PMUs and the two PDCs have come in under budget, leaving room for PacifiCorp to add additional PMUs to the bulk electric system. Three additional substation sites have been chosen, Monument, Emery and Dave Johnston Plant, and the necessary equipment is being ordered to facilitate the installation of these additional PMUs. The current schedule calls for these three sites to be completed and the PMUs streaming data to WECC by the end of 2013. The installation of these additional PMU sites will satisfy PacifiCorp's commitment to the synchrophasor project.

WECC has released the initial test version of their WAN, which includes a Wide Area View (WAV) tool. The WAV tool allows users to see all of the participating PMU sites in the Western Interconnection and all of the real time data that they provide. This version was released to allow participating entities the opportunity to navigate the program and submit their feedback to help improve the actual WAV tool[24].

Timeline

Participating utilities are scheduled to complete the installation of all respective PMUs and have data streaming to WECC by the end of September, 2013. Overall, WECC anticipates closing this initial phase of the project by the end of April, 2014. WECC expects the installation of PMUs to continue in the Western Interconnection even after satisfying the goals of the WISP incentive program.

[24] Western Electricity Coordinating Council, "WAV." https://www.weccrc.org/realtime/Pages/WAV.aspx (accessed 7/21/2013).

Dynamic Line Rating Projects

Overview
PacifiCorp engineering standards currently use static winter and summer ampacity limits to rate lines. Installing DLR systems in certain locations will allow the Company to monitor lines for potential loading to maximize power flow based on real-time conditions instead of the static seasonal ratings. One necessary precaution that must be taken when determining the applicability of DLR on a line is determining whether the line itself is the limiting factor in the transmission path. DLR will not be the appropriate technology to implement if equipment on the path turns out to be the limiting factor, as this would create the danger of increasing the power beyond the weaker element's handling capabilities. Company planners and engineers must keep this in mind when determining locations for potential DLR application.

Analysis
PacifiCorp has identified two locations within its transmission system where real-time dynamic thermal line rating (DLR) systems will be beneficial: the first DLR equipment installation was implemented on the 31 mile long 230 kV Miners-Platte line located in the southern part of Wyoming; the second project will install DLR systems on three of the 345 kV lines from Populus substation to Borah and Kinport substations located in the southern part of Idaho, having a combined length of 147 miles.

Real-time monitoring systems will be used to increase the maximum power flows through these circuits while avoiding clearance infringements and physical damage to the conductor systems on the lines. The key benefit of DLR technology is to optimize the transfer capability of the existing transmission system with minimal capital investment. In both applications the line conductors are aluminum conductor steel-reinforced (ACSR), electrical clearances at maximum temperature are a concern, and the sections to be dynamically rated are over 30 miles long.

PacifiCorp selected the CAT-1 line monitoring system offered by The Valley Group for both projects. The CAT-1 system calculates dynamic operational line ratings (amperes or MVA) using line section tension readings from load cells installed on the lines. Measurement data is taken from multiple sensing locations throughout the lines and the data is communicated via radio to a central master station located at a substation. The master station processes the information and communicates it to the Company dispatch center. The dispatcher has a screen display that shows the real-time maximum rating of the line, enabling the dispatcher to make load-related dispatch decisions that utilize the maximum real-time load capability of the line.

Completed and Future Actions/Timeline

The 230 kV Miners-Platte line received phase 3 rating approval from WECC in early 2013, which indicates that the study is concluded and the project may be placed in service. The multiple-line 345 kV project on the transmission lines west of the Populus substation is currently under construction and is scheduled to be completed and operational in Spring 2014. As this is a more complicated installation, the test phase of this project will be longer than the Miners-Platte DLR project test phase. More information on this topic can be found in the attachment Exhibit B.

Conservation Voltage Reduction Pilot Project

Overview

PacifiCorp's recent CVR analysis began as a response to a Washington voter-approved initiative, codified as RCW 19.285[25] in Washington State. This initiative calls for regulated utilities to pursue cost effective, reliable and feasible distribution efficiency savings. PacifiCorp worked with the Washington Utilities and Transportation Commission's Demand Side Management Advisory Group to define the CVR pilot's scope and cost recovery mechanism in order to ensure compliance with the state's requirements.

Analysis and Completed Actions

In 2011 a group of nineteen distribution circuits in Washington State were studied for potential energy savings. Four of these circuits were selected for a 2012 CVR pilot project. Of the 0.09 aMW predicted to be acquired through the four pilot circuits, less than 0.01 aMW was actually achieved. Both before and after voltage reduction, all four circuits failed to meet the protocol efficiency thresholds required for rigorous measurement and verification. Thus, the energy savings could not be verified by the approved method, since the Simplified Protocol[26] scope requires that the thresholds be met. The estimated savings from the metered data, ignoring the threshold violations, is 0.017 aMW at the Clinton substation and zero or negative energy savings at the Mill Creek substation.

Due to the level of estimated savings the Clinton pilot was not found to be cost effective. Less than half of the anticipated reduction in average voltage was achieved and the estimated cost of energy savings was $112.49/MWh, which is 23% higher than the avoided purchase energy rate used in Washington. Due to protocol threshold violations, confidence in both the voltage reduction value and energy savings value are consequently very low. For the purposes of reporting savings toward the Company's 2012-13 conservation targets in Washington, zero energy savings will be claimed for both Clinton and Mill Creek due to the inapplicability of the

[25] Washington State Legislature, "Chapter 19.285 RCW Energy Independence Act." http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285 (accessed 7/15/2013).

[26] Regional Technical Forum, "Utility: Voltage Optimization Protocol." http://rtf.nwcouncil.org/measures/measure.asp?id=180 (accessed 5/22/2013).

protocol scope. Future system reconfiguration needs identified around Clinton substation further highlight the danger of long-term energy savings predictions.

With regard to the reliability of energy savings from voltage reduction, the pilot project showed that actual energy savings appear to be less than one tenth of that predicted by rigorous and detailed system analysis. A second study, named the Tier 2 study, highlighted limitations in circuit analysis as a project risk and led to the conclusion that energy savings from voltage reduction cannot currently be reliably acquired at PacifiCorp.

With regard to the feasibility of energy savings from voltage reduction, the pilot project helped the Company appreciate the difficulty in accurately predicting feeder voltages at varying load levels. State estimation and Advanced Metering Infrastructure research conducted by the Electric Power Research Institute and the Institute of Electrical and Electronic Engineers in 2012[27] highlighted the critical nature of this industry hurdle. The Tier 2 report also acknowledged that load variations create challenges when measuring small voltage and energy changes.

Future Actions

Existing Company practices were a principal component of the 2010-2013 analysis. These practices include utilizing line drop compensation and minimizing the total cost to company and customer through prudent system improvements. These practices tend to have a negative effect on CVR benefits, since the Company has already gained much of the financial benefits of typical CVR projects. This, coupled with the fact that detailed studies of circuits do not yield reliable predictions of energy savings potential, as well as problems with the measurement of small energy savings causing costly complications leads to the conclusion that energy savings from CVR cannot currently be achieved in a cost-effective manner. A periodic review of the state of the technology, measurement protocols and the economics of such projects will be included in future editions of this document.

Communicating Faulted Circuit Indicators

Overview

Non-communicating faulted circuit indicators (FCIs) have been used for years to visually indicate fault locations on PacifiCorp's distribution lines. Recent advances in technology have enabled communicating faulted circuit indicators (CFCIs), that can send alerts to operations centers and mobile troubleshooters, as well as enabling the ability to log data for engineering planning and analysis. Due to recent expansion, PacifiCorp has begun researching CFCI

[27] R.F. Arritt, R.C. Dugan, R.W. Uluski and T.F. Weaver, "Investigating Load Estimation Methods with the Use of AMI Metering for Distribution System Analysis," IEEE, 978-1-4673-0336-1, 2012. http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=6194567&url=http%3A%2F%2Fieeexplore.ieee.org%2Fstamp%2Fstamp.jsp%3Ftp%3D%26arnumber%3D6194567 (accessed 7/31/13).

applications in Utah. Analysis of the costs, benefits and best practices will then be applied to all of the company's distribution systems.

CFCIs have the potential to improve reliability indices such as customer average interruption duration index (CAIDI) by reducing the amount of time between the initiation of a fault and its detection and location. The fault location function of a CFCI operates by sending a signal to an outage management system or a troubleshooter, indicating that a fault has occurred and giving its approximate location. This data can be sent as a simple GPS coordinate or other locational data point or it can be incorporated into a more advanced algorithmic system which may be able to pinpoint the potential fault locations more precisely.

Many CFCIs also have the ability to transfer line loading data, temperature and other line parameters, which enables planning and algorithmic waveform analysis which can be used by planners and engineers to optimize circuit design and detect incipient faults.

<u>Analysis</u>
Engineers at PacifiCorp are currently researching circuits on which CFCIs may prove most beneficial and are analyzing the potential impact of these sensors on reliability indices and planning processes. A preliminary cost/ benefit analysis was conducted to determine the value of applying CFCIs to a number of circuits with higher CAIDIs. In the Rocky Mountain territory less than 60 circuits exhibited a positive benefit/cost ratio with seven showing benefit/cost ratios above two. More information on this topic can be found in the attached Exhibit B.

<u>Completed and Future Actions/Timeline</u>
In light of this analysis, PacifiCorp engineering is in the process of implementing a pilot project in the Rocky Mountain Power area in the next twelve months to fully ascertain the benefits and costs of these communicating sensors and to gain experience with the operational elements involved in their application. An update on this project will be included in subsequent smart grid reports.

Customer Engagement

All PacifiCorp customers have access to view and download up to 24 months of electric usage history as well as the option to download up to 12 months of data that meets the Green Button standard specification. Green Button data is formatted in a machine-readable language that customers can use with software applications or provide to a third party to evaluate their energy use, giving customers a greater understanding of their habits and how it impacts energy use and efficiency. PacifiCorp also provides information to customers about the benefits of the Green Button standard, how customers can use the analytical results of the data to improve grid performance, and offers links to apps that customers can use.

PacifiCorp also works collaboratively with entities such as the Energy Trust of Oregon to increase customer awareness of the benefits of energy efficiency and to help increase customer participation in Energy Trust services and cash incentive programs. PacifiCorp and the Energy Trust are currently preparing to launch a behavioral program to provide 15,000 targeted residential customers with information about their electricity use through personal energy reports. The reports will compare a customer's electricity use to that of similar homes in the area and provide customized energy-saving recommendations.

By utilizing programs like these and partnering with entities that focus on energy efficiency and enhancing customer awareness, PacifiCorp strives to empower its customers to take control of their energy usage and leverage their knowledge of how the power grid functions to further optimize their energy usage. This approach in turn allows for lower overall costs and improved grid efficiencies, which benefits all involved stakeholders.

Direct Load Control Cool Keeper Program

Overview

In 2003 PacifiCorp launched the Cool Keeper program in an effort to manage summer peaks in the Wasatch Front area and to study the feasibility of direct load control on the system. Residential and small commercial customers were invited to participate in the program, which allows the Company to manage air conditioning loads a limited number of times during summer months. Customers were then provided with a twenty dollar credit per year on their bills for their participation.

Analysis

The Cool Keeper program directly controls customers' air conditioners with a radio-enabled device which cycles the compressors off and on. With the current number of Cool Keeper load controls installed the Company has control of up to 121 MW of power during critical peak events. A third-party evaluation[28] completed in March 2012 highlighted a number of aspects of the Cool Keeper program:

- 91% of participants were satisfied with the program
- High in-home temperatures were the main reason for opt-outs
- Unit tonnage eligibility compliance with tariff requirements is hard to verify without a measurement and verification process in place

[28] The Cadmus Group, "Rocky Mountain Power 2009-2010 Utah Cool Keeper Process Evaluation." http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/UT_Cool_Keeper_Report.pdf (accessed 6/24/2013).

- Promotional materials and marketing efforts have been effective in improving customer understanding of the beneficial impacts of the program

Timeline

The Company's research[29] indicates that over the next 20-year period a total potential of 143 MW may be available in the Rocky Mountain Power territory and 27 MW may be available in the Pacific Power territory. PacifiCorp is currently in the process of upgrading the existing Cool Keeper system to improve the remote devices and enable measurement and verification of savings during events. This upgrade is expected to further improve the Company's understanding of effective DSM measures and increase the overall efficiency of the direct load control system.

Pay-For-Performance Irrigation Program

Overview

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

Analysis

In 2010, the Company initiated a review of its Irrigation Load Control Program in an effort to understand the impact of the program on its system. Given the challenges regarding the geographic location of Utah irrigators, lack of interval data and the inability of the Company to obtain aggregated data from system meters, the analysis was limited to Idaho irrigators. A third party review of the 2009 and 2010 control seasons indicated that realized reductions ranged from 17% to 86% of expectations depending on the month and hour the load curtailment event occurred.

During the 2012 Program Season, the Company called 12 control events. Given the number and dispersion of events and the ability to analyze the Idaho program at an aggregated level (due to the concentrated nature of participants and the availability of system data), the Company was able to gain a further understanding of the system's performance over the entire control season.

The average realized load reduction for the 2012 Program Season was 139 megawatts, or 57% of the participating load. During the ten-year system peak period (ten year actual system peak days) the 2012 average realized load reduction was 117 megawatts or 48% of the 244 megawatts of participating load. Incentive payments or credits to participants for 2012 were based on all 244

[29] The Cadmus Group, "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume 1." http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf, page 34 (accessed 7/31/13).

megawatts of participating load. Participating load is the sum of the non-diversified peak demand associated with the participating sites, including the demand placed on the company's system during off-peak hours associated with loads associated with golf courses, cemeteries, etc. This data is illustrative of the performance of the Company's current irrigation load control programs in Idaho. While similar data regarding the performance of the Utah Irrigation Load Control Program is not available, it is reasonable to assume that results in Utah have been similar to the program performance in Idaho.

The Company has been able to reduce operating costs for 2012 by renegotiating the scope of its contract with its service provider and utilizing inventoried equipment as it prepared for a new request for proposal (RFP) for control equipment and services. During 2012 the Company issued a request for proposal in an effort to identify alternatives to deliver the program in the most cost efficient manner. The RFP asked respondents for two options:

> Option 1: The contractor would deliver the dispatchable irrigation load control program under a fully outsourced pay-for-performance model, accepting all the costs and risks to create, maintain, and manage the program. This option required respondents to provide capacity, provide both monitoring and load control devices, and pay incentives to customers.
>
> Option 2: The Company would continue operating the dispatchable irrigation load control program, with an internal program manager utilizing contractors for the field operations, program database, dispatch software, and customer interface activities. To support a Company operated program contractors were asked to provide proposals for equipment installation, operation, maintenance, and customer service associated with the program under the terms specified in the RFP.

While the focus of the RFP was on the existing programs in Utah and Idaho, proposals were also obtained for California, Oregon and Washington.[30] Targeted load reductions were established for each state.

The Company received five proposals from two qualified vendors; two pay-for-performance proposals and three equipment and service proposals. The proposals were evaluated to determine the least cost option after consideration of risk. To facilitate this evaluation, the incentive level and structure currently approved by the Idaho and Utah Commissions were utilized.

[30] Pricing information for irrigation load control in California, Oregon and Washington were provided for inclusion in the Integrated Resource Planning model.

The results of the pricing analysis of the five proposals on a cost per kilowatt of realized reduction gave the least cost option as the pay-for-performance proposal submitted by EnerNoc, Inc. In addition to being the least cost option, EnerNoc assumes all equipment and delivery risks associated with the program.

EnerNoc currently manages over twenty-five pay-for-performance contracts in the United States. The equipment being proposed by EnerNoc is a two-way communication solution designed specifically for irrigation load control applications by capturing and communicating near real-time irrigation load data on five-minute intervals, and enabling direct control of irrigation pumps and equipment.

EnerNoc's pay-for-performance proposal was selected, based on the pricing, risk and technical evaluations performed during the RFP process. Negotiations regarding the final agreement began shortly after the vendor selection.

Completed and Future Actions

Based on the 2011 Integrated Resource Plan, the Irrigation Load Control Program is cost-effective based on the utility cost test. The 2013 Integrated Resource Plan includes as an existing resource the 40 MW of Average Demand Response Capacity associated with the EnerNoc agreement. Pricing information for incremental irrigation load control in Utah was provided for inclusion in the Integrated Resource Planning model and, if selected, the contract will be modified to include the additional capacity requirement.

Distributed and Renewable Resource Enhancements

Overview

Since 2010, PacifiCorp has offered volumetric, net metering and expected performance-based incentives to its customers who install qualifying equipment on their homes and small businesses, including photovoltaics, internal combustion engines, micro (hydro) turbines, wind turbines, external combustion engines and fuel cells. PacifiCorp also provides expertise and assistance to customers for net metering and grid interconnections to ensure safe installations. Through 2012, Pacific Power customers have installed 4,710 kilowatts of solar energy through the Oregon Solar Incentive Program. PacifiCorp plans to add approximately 15 MW of distributed solar resources system-wide by 2033, as detailed in the 2013 IRP (p. 205). These distributed solar resources will help reduce emissions, increase reliability for customers and provide a testbed for optimizing the integration of distributed generation into the electrical grid. This experience is crucial for helping customers and engineers understand how to safely and effectively integrate disparate and relatively low power electricity sources into the power grid, as these types of resources are expected to increase over time.

Analysis

PacifiCorp continues to refine its wind integration modeling approach in an effort to maintain system reliability when integrating the 1,400 MW of owned and contracted wind capacity that makes up 8% of the annual energy delivered by the system. A technical review committee was assembled in 2012 and tasked with methodically analyzing results produced by simulations of operational planning, scheduling and real-time operation of the bulk power system, using data obtained at a granularity of hourly over at least one year. Although these simulations have historically had fidelity issues, the advent of actual historical production data for wind generation gave the technical review committee unprecedented levels of data with which to work. Although not perfect, this level of detail, along with other high-fidelity data sources, has led to an integration study which is much improved over past ones.

The Company strives to research and support distributed and renewable resource projects that provide benefit to customers and help to further evolve towards cleaner fuel sources. Between 2010 and 2012 the Company acquired 160 MW of renewable resources and continues to research combined heat and power, geothermal, wind and other efficient and renewable sources of energy. These include a recent request for proposal for a solar facility, which led to the acquisition of the Black Cap Solar Facility, currently generating 4,500 MWh annually. Acquisitions such as this help move PacifiCorp forward as a steward of the environment and integrator of renewable resources.

Challenges and Risks

While there are many benefits to the smart grid there are also many challenges involved in its deployment and its impact on future operations of the electric system. Some of these challenges relate to integration of communication standards and device interoperability, ensuring proper security for devices, systems and customers, refining and determining appropriate levels of communication with customers, and the impact that disruptive technologies may have on the electric distribution system and workforce.

The electric system in place today is a result of an expansion that was predicated upon economics, and as such, was engineered to minimize costs, with redundancy and reliability having been seen as lower priorities. As growth occurred, that fundamental design precept has not significantly altered. The fundamental economics are no longer the most critical aspect of the system; rather, the ability of the customer to engage with the electric delivery system is of higher priority. This shift in focus will result in significant costs for current and all future system investment. Equipment, communications protocols and even staff will be more technologically advanced, and will require more routine “refreshing” to maintain compatibility with future advancements.

Interoperability Standards

The current dearth of interoperability standards risks premature obsolescence of equipment and software installed prior to their widespread adoption. As electric utilities continue to expand existing infrastructure and implement new smart grid related systems, long-term investments should support a corporate strategic plan to minimize the risk of technology obsolescence. There are currently several working groups developing standards for the entire spectrum of equipment, devices and end points for the metering and smart grid systems, including interoperability of components. The EISA of 2007 specified that the Department of Energy champion this effort. The DOE authorized NIST to develop uniform protocols that facilitate information exchange between smart grid devices and systems[31]. These standards, along with industry adoption, are crucial to the mitigation of risks associated with implementation and deployment of the smart grid throughout PacifiCorp’s service territory.

NIST is also drafting standards to address issues of interoperability between AMI vendors and has issued its “roadmap” for developing the necessary standards. NIST has cautioned that “as they mature, these standards are undergoing revisions to add new functionalities to them,

[31] National Institute of Standards and Technology, “NIST Framerwork and Roadmap for Smart Grid Interoperability Standards, Release 2.0.” http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf (accessed 7/31/2013).

integrate them with legacy standards, harmonize them with overlapping standards, and remedy shortcomings that are revealed as their implementations undergo interoperability testing."[32] To this end, the NIST framework endeavors to utilize the reporting and experiences of ARRA grantees to work with standards development organizations and standards setting organizations to improve foundational smart grid standards.

The smart grid initiatives that have evolved over the past few years have given rise to a wide array of new markets and opportunities based on innovative technologies. This stresses how important interoperability standards are to a functional, reliable smart grid.

Stakeholders who are not monitoring NIST's activities risk having current investments become prematurely obsolete and will be more challenged in realizing all the benefits that are expected from existing equipment. In addition, many of the smart grid standards under review are immature or non-developed while some prominent standards are not included, emphasizing the need for electric utilities and commissions to remain conservative in developing plans for smart grid systems until standards are established and are proven to deliver expectations.

Security

The smart grid increases the amount of intelligent data to a level never before seen in the power industry. This data includes priority data for electrical system operation, customer data and usage patterns, and generation and transmission operational information. This data will be transmitted mainly over secure communication systems, many of which will have wireless components. The fact that the data is transmitted wirelessly increases the risk of cyber-attacks against the electrical infrastructure.

The security of customer and operational data presents one of the greatest unknown risks of the smart grid at this time. The North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP)[33] reliability standards were designed to protect the bulk power system against potential cyber security attacks, but these standards do not yet address the evolving smart grid market and the vulnerabilities that may be present as more utilities install advanced communications networks. As utilities progress towards the smart grid, enhanced security measures and more stringent requirements will be necessary. Their enactment will increase the overall cost of managing the smart grid. This increase in operational cost is not reflected in this study.

[32] Ibid, page 20.
[33] North American Electric Reliability Corporation, "NERC CIP Standards," http://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx, (accessed 7/31/2013).

PacifiCorp is currently participating in grid security studies hosted by NEETRAC and financially backed by DARPA. The studies are attempting to prove or disprove the feasibility of a fingerprinting technique which will detect anomalous activity on transmission and substation SCADA systems. If the testbed is proven out it will enable utilities to automatically quarantine malicious devices as soon as they are detected. The project is focusing on open source coding and off-the-shelf systems in order to keep the solution flexible and low-cost.

The PacifiCorp Smart Grid department is dedicated to supporting research that focuses on the integrity and security of the grid as technologies evolve. Participating in security-related research groups and projects helps ensure that the smart grid solutions that the Company employs maintain appropriate levels of encryption and malicious activity detection, providing the level of security required to protect customer and Company data.

Customer Communications

The smart grid presents a new and fundamentally different channel of communication between PacifiCorp and its customers. Transmission of usage data can be conducted in real time, not just on a monthly basis as is currently the case. Broadcasting pricing alerts to smart thermostats, email addresses and text messaging devices happens virtually instantaneously. Responses from customers can be immediate, as in the case of a customer who pushes a button on their smart thermostat or visits a website using Greenbutton data[34] to inquire about their charges-to-date. Enabling customers to optimize their experience with evolving technology and helping them understand the benefits of advanced metering is a crucial element of a smart grid deployment.

Legacy system platforms were not designed to handle real time events such as the ones noted above. They were designed to operate on regularly scheduled cycles of batch processes. From PacifiCorp's perspective, modifying or replacing those old reliable cycle-and-batch systems is a challenging prospect with potential for unforeseen challenges that could result in significant cost overruns.

Another challenge that PacifiCorp will face is customer recruitment. DR programs should preferably be opt-out programs. To retain customer participation, PacifiCorp will need to reach out to eligible customers and educate them on the benefits of these programs to maintain a significant rate of participation. This may require the services or a third-party marketing firm or, if done in-house, new software functionality to handle DR recruitment, enrollment, and customer management as well as DR program management. In addition, utilities will need functionality provided by some meter data management systems (MDMS): management of communications to field devices, tracking of devices and their relationships to customers and premises, and

[34] "Green Button – About" http://www.greenbuttondata.org/greenabout.html (accessed 7/6/2013).

provisioning of devices upon installation. The new software will have to be able to scale, allow multiple users, and interface with the call center, an integrated voice response unit, and the Internet. It will also need to interface with the billing system, MDMS, the DR equipment installation company, and various DR communication systems.

PacifiCorp will also need to re-examine how customer service is provided during deployment and after the AMS is completed. The call center will need to be able to effectively work with customers to take advantage of more detailed information on energy use and spending and how to apply it to customer concerns. This includes providing the customer education needed to increase understanding of the benefits of smart metering and reduce fear and distrust of the system changes.

Call center representatives must also have a strong understanding of the end-to-end business process and changes. Once the systems and processes are implemented, representatives must be prepared to handle a complicated set of questions and issues. This requires representatives to have training and access to the applications and information to provide quality responses.

Meter Data Management

The smart grid also results in a paradigm shift regarding metering data. Today, the meter reading system creates monthly files of meter reads and submits them to the billing system. With the smart grid, PacifiCorp becomes a communications company that handles millions of data transactions every day. With 1.8 million meters, just the simple transactions involved in the meter-to-cash function are completely transformed. When the numerous other functions are considered (meter provisioning, outage management, DR events, verification and reporting of energy saved, etc.) the enormity of the challenge becomes clear.

To illustrate, every day the AMS operations team must support:

- More than 45,000,000 meter reads per day (assuming one-hour interval data)
- More than 4,000 meter exchanges per day during deployment
- More than 500 customer moves per day (based on 10 percent yearly turnover)
- 10,000 missing reads per day (99.5 percent daily read success)
- 10 meter failures per day (0.25 percent annual failure rate)
- 10,000 data changes per day

One certainty about the smart grid is that applications and data use will evolve and change over time. The solutions to support smart grid initiatives must not only accommodate but also thrive on such change. By planning for the full range of functionality from the beginning and selecting solutions with the right architecture PacifiCorp can ensure that it not only meets today's broad requirements, but can also meet new requirements that will develop in the future.

Distributed Generation

Distributed generation (photovoltaic systems, fuel cells and other on-site electricity generating systems at customer premises) has the potential to change the dynamics of operating an electrical distribution system. Electrical distribution systems have historically been operated as a "one-way" delivery system moving the required energy from the distribution substation to the end-use customer. As more distributed generation sources appear on the grid, the distribution system must be modified to operate with significant two-way energy flows.

Without the appropriate smart grid technologies in place distributed generation will be a disruptive technology that will negatively impact the distribution system. Standard protection systems, including sectionalizers and fuses, will not be able to provide the proper protection schemes required to maintain the reliability of the system. The smart grid will require the installation of multiple protection devices that have bi-directional measurement capability and built-in analytics, allowing them to respond to and isolate faults while protecting the system from stability issues related to end-of-line generation sources. As the number of distributed generation systems increase, the need for a smart grid will become more apparent.

Distributed generation requires the measurement of electrical energy in both directions. Energy delivered by the electric utility and energy received by the grid must be measured to provide the appropriate billing charges and credits for energy consumed and produced by the customer. To accurately measure both quantities, bi-directional metering must be installed at each location where distributed generation systems exist. Meters capable of measuring energy in a bi-directional manner cost significantly more than standard one-way measurement meters. This increase in meter cost is not reflected in the economic analysis of PacifiCorp's smart grid program.

PacifiCorp has performed studies to evaluate potential sites for solar installation and continues to work with customers, city officials and other stakeholders interested in connecting distributed generation systems to the Company's electric grid. Further, the Company has taken a proactive approach to address customer concerns and has recently released an interconnection guide for customers looking to connect generator systems rated at 2 MW or less. It is the Company's hope that this will help customers gain a better understanding of the various interconnection requirements necessary in order for PacifiCorp to operate the grid reliably and safely.

Smart Grid Solar Energy Study

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

The study showed that of the 356 structures within the service area, 237 (67 percent) had rooftops capable of receiving a minimum level of solar insolation per day. Under the scenarios evaluated it was concluded that institutional buildings are estimated to have the greatest potential for installation of PV panels, followed respectively by commercial buildings, unknown land use buildings and single family residential buildings. Further, as shown in Figure 6, the study showed that the time of the maximum solar output does not coincide with the daily distribution system peak of the "Northeast 16" circuit. This illustrates that rooftop PV systems are an ineffective solution for offsetting investments towards distribution infrastructure.

The detailed data, analysis method and results are provided in the "Smart Grid Solar Energy Study" report. A copy of the report can be obtained by contacting PacifiCorp.

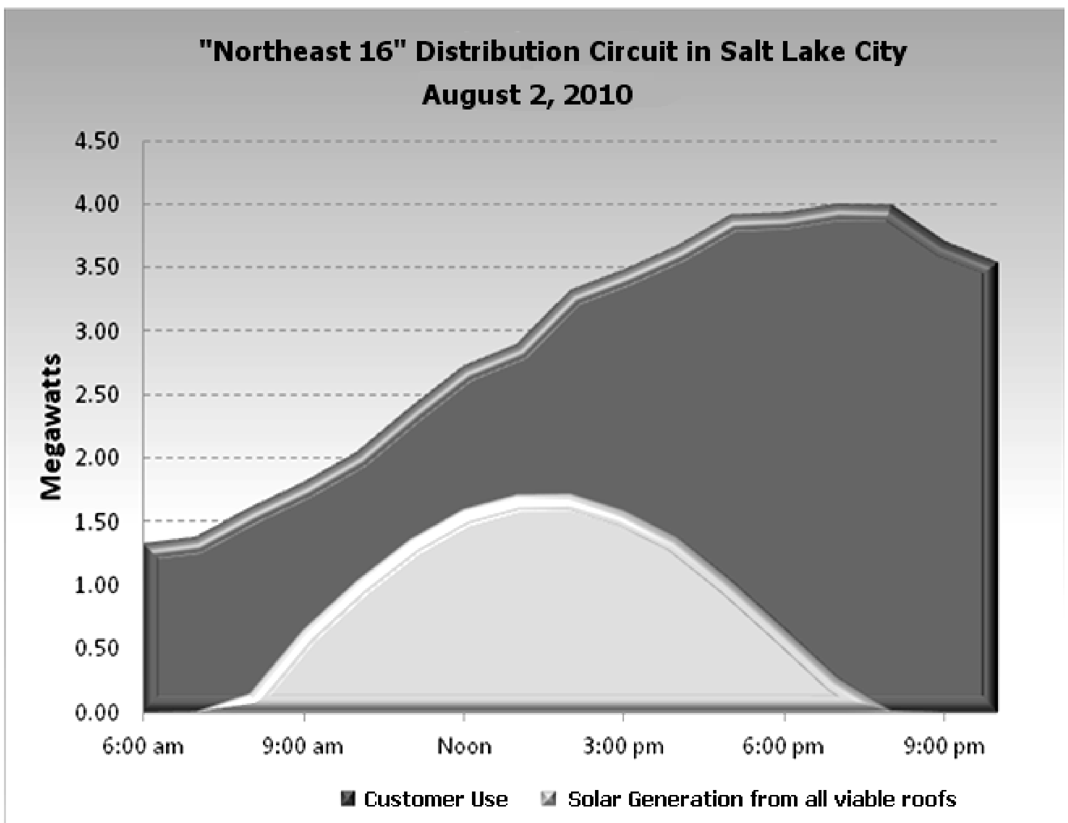

Figure 6 – Daily Peaks for Solar Energy Study

<u>Electric Vehicle Penetration and Vehicle-to-Grid Technology</u>

Plug-in electric vehicles (EVs) are expected to become more widespread as EV and battery technologies advance and EV purchase prices become more competitive with gasoline vehicles. It is commonly accepted that widespread adoption of plug-in electric vehicles will have a large impact on the electrical distribution system in general and distribution transformers specifically.

Future battery technologies and plug-in electric vehicle enhancements may lead to utilizing plug-in electric vehicles for vehicle-to-grid (V2G) and vehicle-to-building (V2B) energy supply for demand response and outage ride-through. At this time PacifiCorp expects plug-in electric vehicles to only be a new load to the system.

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

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

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

The Energy Information Administration (EIA) has been consistently making downward adjustments to their electric vehicle sales growth forecasts to reflect slow economic growth. For instance, in 2007 the EIA forecast[35] sales of hybrid vehicles to be about 1.5 million units sold in 2020; in 2012, that figure was revised to 450,000[36], a downgrade of nearly 70%. This downgrade is consistent for forecasts out to 2030 and indicates that the EIA analysts are predicting a cooling of the electric vehicle market. This cooling trend may change if the national economy picks up, petroleum prices continue to rise or battery technologies continue to improve.

[35] Dept. Of Energy, Energy Information Administration,. "Annual Energy Outlook 2007 With Projections to 2030." ftp://tonto.eia.doe.gov/forecasting/0383(2007).pdf, Figure 52, p. 81 (accessed 7/1/2013).
[36] Dept. Of Energy, Energy Information Administration,, "Annual Energy Outlook 2012 with Projections to 2035." http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf, Figure 91, p. 85 (accessed 7/1/2103).

V2G technology promises quick-response, high-value electric services to balance constant fluctuations in load. However, commercial availability of electric vehicle supply equipment and batteries robust enough to implement this technology remains scarce, even though V2G research provides the engineering rationale and economic motivation for widespread implementation. When battery costs come down enough, energy prices increase enough or technologies arise that allow EV owners to use their cars for arbitrage or emergency backup without fear of voiding warranties or the prospect of a dead car battery before their morning commute, only then will V2G become a viable widespread demand and frequency response tool.

The Electrification Coalition points out some of the main issues with V2G technology[37]:

- Applications are unlikely to appear before third or fourth generation electric vehicles evolve
- V2G technology requires bidirectional chargers, which are more expensive than traditional chargers
- Software development is required by both utilities and equipment manufacturers in order to enable communication between the grid and the in-home chargers
- Researchers need to gain a better understanding of the deleterious effects on battery life when charge/discharge cycle frequency is increased

Companies such as LG Chem, EnerDel and Valence Technology that make EV and grid-tied batteries are finding it hard to stay solvent due to lower than expected demand for electric vehicles, volatility in the economy and a scarcity of investors. Without reliable battery manufacturers, electric car makers, utilities and other companies may find it hard to make long-term decisions concerning centralized and decentralized storage, vehicle batteries and battery-based smart grid applications.

[37]Electrification Coalition. (2009). *Electrification Roadmap.* Retrieved August 15, 2012 from http://www.electrificationcoalition.org/policy/electrification-roadmap, Section 2.4.5 “Vehicle to Home and Grid.”

Economic Review

Each of the components identified for PacifiCorp's smart grid study have quantifiable costs and benefits that were used to determine the rough potential of investing in those technologies. Although no proven costs or savings calculations exist for all of the components, estimates can be used to gauge these costs and benefits. There is also enough established theoretical data on savings opportunities from which a suitable analysis can be built to gauge the relative potential of various alternatives. Many of the benefits are highly variable and dependent on external factors such as values of the future generation capacity and energy markets, percentage of the customer base participating in dynamic pricing programs and the energy conservation achieved by those customers.

All of the cost and savings data presented contains the most reliable data available at the time of publication. A conservative approach was used in all aspects to protect the integrity of the estimates. The cost and savings assumptions will be updated as actual and time proven data becomes available to help maintain a current assessment of the potential for investment options.

Benefits and Savings

The benefits of the smart grid can be categorized into two major cost saving areas: Company-based savings and consumer-based savings. Company-based savings are measured as a direct reduction in Company expenses, such as operational and system losses. System loss savings reduce the need for additional generation and off-system energy purchases and are categorized as generation savings.

Consumer-based savings are directly attributed to changes in consumer energy-use behavior and are unproven benefits with uncertain sustainability[38]. These savings are expected to occur through pricing structures that encourage both conservation during peak usage hours and changes in usage patterns that result in a shift towards the morning and late evening hours. Without specific and mandatory time-of-use coupled with critical peak pricing structures consumers are unlikely to have the incentive to make the behavioral changes required to realize the benefits of a smart grid. Models for time-of-use pricing structures are complex and will require significant levels of study and debate to arrive at the proper design. Due to these factors pricing models remain outside the scope of this study.

Measurement of consumer-based savings can only be estimated as a reduction in generation requirements and as measured by the associated marginal pricing. Additionally, Company-based savings could be estimated as a reduction in capital requirements for electrical infrastructure

[38] Carroll, Hatton and Brown. "Residential Energy Use Behavior Change Pilot," http://opower.com/uploads/library/file/3/residential_energy_use_behavior_change_pilot.pdf (accessed 7/20/2013).

expansion and replacement. However, these savings are only temporary in nature as customer load growth will continue to drive infrastructure investments.

Many analyses of smart grid benefits categorize some of the savings into “societal benefits” with the caveat that any decrease in outage time, generation or greenhouse gases or other efficiency measures will benefit society as a whole with cleaner air, more reliable electric service, increased production times and other qualitative benefits. These societal benefits are difficult, if not impossible, to quantify with any degree of accuracy. For this reason, and the purposes of this report, these benefits will not be included in the analysis.

Advanced Metering System

The major risks for deploying advanced metering systems include vendor selection, home area network protocol, interoperability of components and customer acceptance. As previously mentioned, regulatory approval of new and revised time-varying rate structures and customer participation in these rates is a key component for success.

Some utilities are experiencing customer backlash over perceived privacy and RF issues surrounding smart meters. Halt MA Smart Meters is a Massachusetts-based organization whose stated goal is to fight smart meter installations and is currently pushing for a no mandate/no penalty fee opt out. Other consumer groups around the country are taking similar stances. Utilities will need to deal with pushback from groups like these and increase customer awareness of the benefits of smart grid technologies as well as addressing serious concerns. Non-profits such as the Smart Grid Consumer Collaborative (SGCC) are working on websites and informational pamphlets that counter many of the anti-smart meter claims.

As with any new technology, employee training and business process changes must occur to gain the expected benefit of an AMS. Technology specific training has been identified and included in the individual technology cost calculations. Costs for business process changes have not been fully determined, but a reasonable estimate is included for a more accurate cost estimate of a smart grid. The benefits of the AMS result from the reduction in operating costs associated with manual meter reading, field collections activities and customer call handling resulting from erroneous and estimated meter readings.

The costs associated with the accelerated depreciation of the current metering asset will need to be continually calculated and modified as the system is installed. Several areas within PacifiCorp’s service territory have recently been converted to AMR systems and others may be converted where practical. The accelerated cost of depreciation for those systems will be higher than in areas with older metering systems. The cost of accelerated depreciation has not been included in this analysis. That cost will be calculated in a detailed analysis, after the risks of the assumptions are lower. Such an analysis will be completed prior to any regulatory filing for advanced metering or smart grid.

Demand Response

The AMS presented in this business review is the enabler for a price responsive DR program such as time-of-use (TOU) and critical peak pricing (CPP). A CPP pricing program is implemented with a TOU tariff as a base. A TOU tariff generally has two sets of pricing on a daily basis: the on-peak price per kWh and an off-peak price per kWh. The critical peak hours are usually kept to within four to six hours that coincide with a utility's daily peak demand hours. For PacifiCorp this would be in the summer afternoon/early evening.

In addition to the TOU tariff a CPP rider would be included. The CPP rate would be a change to the on peak energy price for the day a critical peak pricing event is called. These events would be available to be called, if needed, up to 20 times per summer depending on the utility tariff design. For the CPP scenarios in this analysis, 10 CPP event days per summer are assumed. Generally, the critical peak days are expected to coincide with heat waves on weekdays, when customer loads are the highest.

To give customers time to prepare for the curtailment, CPP event days could be called 24 hours in advance. Notification to customers would be through devices placed in customers' homes and businesses as well as through email, texting and social media channels.

The enactment of TOU and CPP programs and rates would require regulatory support in Company jurisdictions. The benefit assumptions for DR in this review assume mandatory TOU and CPP for residential and small commercial customers. Absent regulatory support for mandatory programs, the assumed benefits would need to be revisited and will likely result in higher costs and lower overall benefits for this investment.

Three scenarios were evaluated to identify one option to include in the economic analysis. The three scenarios are described below.

For all scenarios, the majority of the load response to CPP events would be from customers with central electric air conditioning and heat pumps. Either through an automated response, or customer manual adjustment, thermostat settings would be raised during CPP events reducing the coincident demand of air conditioning on the system until the event ended. Customers with window air conditioning units could manually adjust their temperature settings as well. Other responses expected would be reducing lighting and plug loads. Customers could also delay operating dish washers, clothes washers, dryers and electric oven/range cooking and turn down electric water heaters manually or with a timer.

In all scenarios, there are ongoing costs such as customer education, CPP event notification and software licensing and/or maintenance. Additional recurring costs include costs associated with load reduction evaluation, customer churn and growth and the replacement of control and notification equipment.

The benefits of the tariffs in each scenario consist of demand and energy reduction during the CPP events, along with the cost of additional energy use (higher than normal) after a CPP event due to loads that are shifted (delaying dishwasher usage and air conditioner take-back) rather than simply reduced (lighting, plug loads).

The benefits quantified include two sources: avoided capacity costs and energy cost savings. The avoided capacity costs represent the avoided peak megawatts multiplied by the expected value of the forward capacity market. The energy cost savings represent the lower cost of purchasing capacity during off-peak hours as compared to on-peak hours.

In developing the assumed response rates, costs and benefits for the three scenarios it became apparent that the data available on which to base the assumptions and calculations was limited. Participation in nearly all TOU rates for residential and small commercial customers in operation today are voluntary and the data available from smart grid enabled DR pilot programs, while informative, remains insufficient to accurately predict results on a larger scale, across multiple jurisdictions, and in a low retail rate environment.

Scenario 1- Mandatory TOU/CPP

This type of rate structure is expected to encourage energy usage away from the daily peak load periods. Additional demand reduction could be achieved under this scenario with occasional CPP events triggering higher prices, which are more reflective of the costs associated with meeting critical peak demand. The CPP tariff would apply to all residential and commercial customers. All customers would be given a basic CPP event indicator device that has three color-coded indications of relative kWh pricing, representing off-peak (cheapest pricing), on-peak pricing, and critical peak pricing. Signaling to the device would be through the smart grid’s communication system into the home. Only one-way communication to the device would be necessary. Customers could choose to sign up for day-ahead notification through email, texting and social media channels.

Customers could also choose to purchase a more robust notification system like an in-home display (IHD) that gives the customer actual kWh pricing, in addition to notification of CPP events. Another option for customers is the purchase of devices to help automate their response to CPP events, such as a programmable communicating thermostat or a home automation system. These types of devices would automatically respond to CPP event notifications and reduce customer energy use to a pre-set level determined by each customer, providing the greatest opportunity for DR and energy use reductions. To help improve customer response to CPP events, PacifiCorp would offer a coupon for upgrading to an IHD, a communicating thermostat, or a home automation system. Most of the costs for this CPP program would be in the initial rollout of the tariff, purchase and distribution of basic CPP indicators, notification and control systems, equipment coupons and customer education. The majority of these costs would be spent in the first two years of the tariff implementation. Ongoing costs would consist of consumer education to maintain persistence of response during events, customer growth, assisting with the costs of replacement equipment due to customer movements and equipment failures, and the evaluation of the resulting load reduction.

Scenario 2 - CPP Opt-Out

This scenario is similar to Scenario 1. All customers would be put on the TOU and CPP rates as a default tariff. Customers would have the ability to opt-out of the CPP part of the tariff and only be on the TOU rate. This rate would have an off-peak period rate higher than the TOU rate with the CPP component to incentivize customers to stay on the CPP rate. With the exception of the marketing strategy, all of the other features in Scenario 1 would be the same in Scenario 2. It is expected that customer participation would stabilize during the first two years of the tariff implementation.

Scenario 3 – CPP Opt-In

For this scenario, all customers would also be on a TOU tariff to encourage energy usage away from the daily peak load periods. PacifiCorp would market the CPP tariff to customers. The incentive for customers to participate would be a CPP event indicator that also indicates the daily off-peak and on-peak hours, as well as the CPP events. In addition, the off-peak rate would be lower for this tariff than for the default TOU tariff. To help customers enhance their load reduction response, a communicating programmable thermostat or a basic IHD would be offered to participating customers, as well as a coupon to upgrade to a more sophisticated IHD or a home automation system. The utility would send a signal to the thermostat or home automation system initiating an automated response to the CPP event based on each customer's desired response to events. For example, a customer with a programmable communicating thermostat could choose to have their temperature setting raised by five degrees in response to CPP events. It is expected that, with focused marketing and communication, it would take about 4 years to build the customer participation to the levels predicted in the financial analysis.

In addition to the costs in Scenarios 1 and 2, this scenario would have higher marketing costs associated with customer acquisition and the cost of the thermostat or IHD provided as an incentive.

To maximize the benefits of DR in this review, the costs and benefits of Scenario 1(mandatory TOU with a CPP component) will be used. Scenario 1 provides the highest value in the business review with the lowest assumed implementation cost and highest assumed DR from customers. The voluntary nature of Scenarios 2 and 3 increases initial and ongoing marketing costs while in many cases also results in diminishing value from participants, many of whom are likely participating because the on-peak and off-peak pricing schedules align closely with normal usage patterns.

Under all three scenarios, the review suggests that if advanced metering and the associated communications were in place the deployment of DR on a broad scale would be beneficial.

Adjustments were made to the costs and benefits of DR for the residential and small commercial load management and pricing programs currently in place[39] and operated by PacifiCorp today. The costs of these programs were netted out of the cost and benefits of the broader DR applications envisioned in a smart-grid enabled environment. Whereas DR is responsible for over 70 percent of the total smart grid benefit, the economic analysis is highly dependent upon the assumptions made for customer participation and retention and future energy costs. Any variance in these assumptions will greatly impact the financial calculations.

Customer Education

There is a limited amount of data available on which to assess the requirements for a customer education program as advanced metering and smart grid technologies are delivered and customer interaction with the technology increases. To arrive at a suitable estimate for customer education costs a review of various utility state filings for advanced metering deployment was conducted. Of those initial filings reviewed, only Oncor Electric Delivery Company's included a line item for customer education. Their advanced meter deployment includes a $15.1 million comprehensive customer education program called "SMART TEXAS - rethinking energy" that will educate retail electric customers about the benefits that can be achieved through the use of an advanced meter. To properly account for customer education programs throughout PacifiCorp's service territory, a conservative cost of $12 million has been included. This value

[39] The costs and benefits of Utah's Cool Keeper air conditioner load management program were netted out of the assumed costs and benefits of smart grid deployment. No adjustment was made for Idaho or Utah irrigation load management programs, or large commercial and industrial curtailment program as only residential and small commercial demand response was included in the development of this business review.

was derived based on a lower customer count and a larger geographical service territory compared to Oncor.

Distribution Management Systems

PacifiCorp has a history of managing its distribution systems for optimal power factor, voltage profile, reduced line losses and increased system efficiency. This attention to managing the distribution system has required that numerous capacitor banks and voltage regulators be installed on the distribution system. The cost to migrate to a smart grid is mitigated by the fact that the existing line equipment will only require that the control panel be upgraded to enable two-way communications. In addition to the pre-existing line equipment, additional capacitor banks will be installed and controlled by the DMS in order to create a smoother voltage profile. These additional voltage regulators and capacitor banks may, to a minor extent, further reduce the line losses on the system, resulting in less required generation. The ability of the capacitor banks to automatically report malfunctions will reduce maintenance costs as inspection programs can be reduced or eliminated.

The addition of faulted circuit indicators and automated field switching devices will create additional operational benefits due to reduced capacitor inspections and reductions in manual switching orders. The ability to proactively respond to outages on the system will provide operational benefits in the form of improved reliability indices, reduced outage calls to the call center, a reduction in the number of trouble tickets and a reduction in the number of truck rolls responding to non-outage conditions.

Cost and Benefits Summary

The economics of the smart grid project were evaluated over twenty-five years to cover implementation and the twenty year expected life of the system. The economics include refresh rates for computer hardware, software and communications equipment and the remaining value of transmission and distribution assets installed under this program. The costs and benefits in 2013 dollars associated with each of the technologies defined for the PacifiCorp smart grid are detailed in confidential Attachment A. The costs and benefits are escalated based on the projected inflation rate, except for energy savings, which are valued based on projected power costs.

When reviewing the numbers it is important to remember the technology dependencies as laid out in Figure 5 of this report. For example, the savings associated with DR cannot be achieved without the investment in information technology, metering/distribution wide-area network and the AMS. The six case scenarios presented in the Roadmap section below include these interdependencies.

Roadmap to the Smart Grid

To develop an objective roadmap for the implementation of smart grid technologies the economic value of the individual components must be considered and a determination of the maturity of the technology must be ascertained. Due to the co-dependency of some of the components only the AMS, DMS and TSP systems can be independently evaluated. Whereas TSP is a stand-alone function, this leaves the decision for the roadmap to begin with AMS or DMS. A stand-alone analysis of the key functionalities was performed to identify those with the highest value and to determine the order of implementation. The roadmap also portrays a timeline for implementation that considers both a consistent and level capital expenditure plan and a determination of resource requirements to obtain the number of years required for each component, including pilot installations and system stress testing prior to full-scale deployment.

To determine the proper order of implementation for the smart grid roadmap, the smart grid technologies were grouped into six case scenarios. Case 6 includes the total costs and benefits for the complete smart grid network as defined and follows the roadmap as shown in **Figure 7 – Smart Grid Roadmap**. The included components for each case are shown in Table 3 below. All cases include the required information technology, communications systems and required customer education costs that are necessary to implement the technologies incorporated into each case.

Case	AMS	DR	DMS	FDIR	IVVO	CES	TSP
1	X						
2	X	X					
3			X	X			
4			X		X		
5			X	X	X	X	
6	X	X	X	X	X	X	X

Table 3 – Case Components

Each case analysis generated independent costs, annual benefits and the present-value revenue requirement (PVRR). Due to the high-level nature of this analysis, no sensitivity analysis was completed. All costs and benefits were considered to be "best case scenarios."

With the given analysis, a logical roadmap for implementation of a smart grid at PacifiCorp can be developed, starting with the AMS/DR projects. To properly plan the system, a detailed business case will be required, followed closely with working discussions with the state regulatory commissions and key stakeholders. Figure 7 portrays a potential timeline that provides for a systematic implementation. At the outset and during the duration of the program, ongoing review and analysis of the business case is necessary to ensure that financial integrity and compliance with emerging standards are maintained.

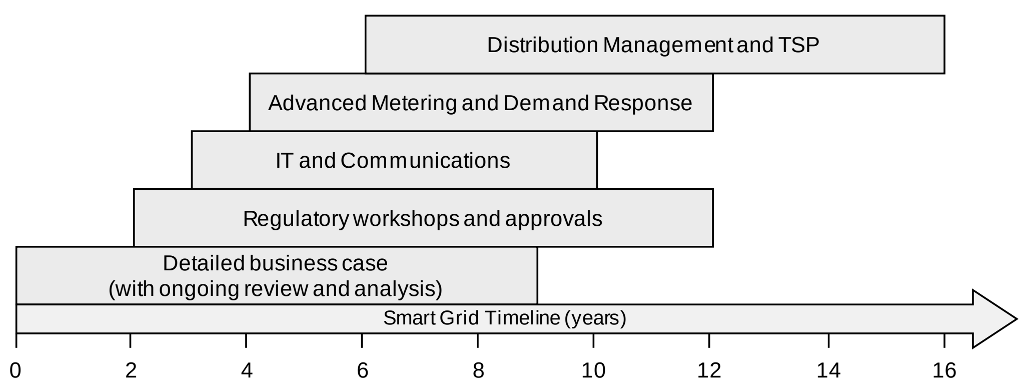

Figure 7 – Smart Grid Roadmap

Conclusion

The present economics to implement a comprehensive smart grid system throughout the PacifiCorp territory are forbidding. However, smart grid technologies do show promise for future improvements in the operation and management of the transmission and distribution systems. Modification of consumer behavior would be central to realizing many benefits. Changes in usage and improved conservation have the potential to dramatically transform the electric industry as well as distributed generation and increased renewable generation.

Most of the benefits associated with DR are unproven and based on optimistic assumptions regarding the number of customers who will change their energy usage and questions surrounding the sustainability of any consumer behavior change remain unanswered. To mitigate the costs and risks to PacifiCorp and its customers, it is essential that the market leaders be identified, that system interoperabilities be verified, and that the Company learn from other electric utilities to ensure that prudent smart-grid investments are made for customers.

PacifiCorp will continue to monitor activities throughout the nation as more advanced metering and other smart grid related projects are developed, as well as continuing smart grid technology research and pilots. These activities will allow for more precise estimates of the costs and benefits of more wide-scale implementations. With large scale deployments progressing throughout the country, the market leaders will become evident and will demonstrate whether an advanced metering infrastructure, demand response system, and other large-scale rollouts of smart grid implementations are supported by the precedent pilot programs.

Appendix A - Common Abbreviations

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

Abbreviation	Name
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AMS	Advanced Metering System
aMW	Average Annual Megawatt (8760 MWh)
CAIDI	Customer Average Interruption Duration Index
CBM	Capacitor Bank Maintenance
CES	Centralized Energy Storage
CFCI	Communicating Faulted Circuit Indicator
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DLR	Dynamic Line Rating
DMS	Distribution Management System
DR	Demand Response
FDIR	Fault Detection, Isolation and Restoration
HAN	Home Area Network
IED	Intelligent Electronic Device
IHD	In-Home Display
IVVO	Interactive Volt-Var Optimization
MDMS	Meter Data Management System
OMS	Outage Management System
PMU	Phasor Measurement Unit
PTR	Peak Time Rebate
RAS	Remedial Action Scheme
RFP	Request for Proposal
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
TSP	Transmission Synchrophasors
TOD	Time-of-Day
TOU	Time-Of-Use
V2B	Vehicle-to-Building
V2G	Vehicle-to-Grid
WAN	Wide Area Network

Appendix B - Smart Grid Technologies at Other Companies

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

- Portland General Electric (PGE), headquartered in Portland, Oregon, has installed more than 825,000 smart meters on customers in their system. This investment has further enabled other smart grid projects, including:
    - The Energy Tracker initiative, which gives customers access to their smart meter data and may help further PGE's demand side management programs
    - Time-of-use pricing for commercial and industrial customers
    - Direct load control programs which will enable PGE to reduce overall system load, currently by up to 17 MW.

  PGE has also incorporated dispatchable standby generation and distributed generation into their system. The Salem Smart Power Project began construction on May 21, 2012 and utilizes customer generation, a 5 MW, 1.25 MWh lithium ion battery energy storage system and automated line switching to increase system reliability. Benefit streams include increasing supply capacity, time shifting load, and firming up renewable capacity.

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

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

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

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

As these projects are in part funded with ARRA grant money their progress will be tracked on the smartrid.gov website. The PacifiCorp smart grid team plans on continuing to watch as projects like these progress in order to learn more about best practices in the smart grid environment.

- Pacific Gas and Electric (PG&E) invested in an 8-10 million smart meter rollout and installation of 300 MW of compressed air storage, expending a projected $800 million to $1.25 billion in capital investments and $500 to $700 million in cumulative operating expenses over 20 years. PG&E hopes to see $600 million to $1.4 billion lower energy procurement costs; $200 to $400 million in avoided capital costs due to offsetting the need to build new power plants; $100 to $200 million in avoided operations and maintenance costs; a 10-20 percent improvement in grid reliability; and 1.4 to 2.1 million metric tons of avoided carbon emissions.

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

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

- Southern California Edison (SCE) has perhaps done more to advance the current state of smart grid technology and understanding than any other US utility. With smart meters deployed to more than 4 million customers and rigorous renewable portfolio standards set by the state commission, SCE has some big challenges as well as opportunities in the smart grid arena.

The Irvine Smart Grid Demonstration, located southeast of Los Angeles on and around the campus of UC Irvine, has multiple elements:

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

The project is taking place on two 12 kV distribution circuits, numerous residential homes and an EV charging parking lot at the UC Irvine campus. SCE is hoping to demonstrate zero net energy home functionality, in which over the course of the year homes will generate as much energy as they consume; reduced greenhouse gas emissions; and evaluate their smart grid implementation capabilities.

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

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

The system will be operating in an area with an ultimate potential of up to 4,500 MW of intermittent wind power. The PacifiCorp smart grid group will continue to follow the project and watch for significant advances in the energy storage field.

REDACTED

EXHIBIT A

ADVANCED METERING PROJECT ANALYSIS

ADVANCED METERING PROJECT ANALYSIS

PacifiCorp has implemented one-way automated meter reading solutions in Washington, Utah, and Wyoming. These projects have succeeded in reducing meter reading costs, improving the quality of service to customers, and improving employee safety.

In February 2012, the Company initiated an effort to find a financially viable two-way advanced metering solution in Oregon. This effort was driven by the Public Utility Commission of Oregon's (Commission) interest in a two-way advanced metering system (AMS) as opposed to an advanced meter reading (AMR) solution. All PacifiCorp analysis of existing AMS at that time proved to not be financially viable.

After performing research and engaging in discussions with major meter manufacturers Elster, Itron, Sensus and others, PacifiCorp began exploring new technology with the capability to migrate from a one-way metering system to a two-way AMS, thereby avoiding the risk of stranded meter investment. This new technology would allow the Company to implement an AMS in two phases. The Phase 1 meter system would operate as a normal one-way automated meter reading system, similar to what PacifiCorp utilizes today in certain territories. The Phase 2 meter system would upgrade the Phase 1 meter system to an advanced two-way system and incorporate an advanced communications network. The two-phase process allows the Company to defer the upgrade to a time when the Company's financial model shows a positive net present value for the investment.

Over the past year PacifiCorp has been evaluating the phased approach solution. This evaluation has been problematic due to meter manufacturers' inability to meet product release dates and deliver the technology results to the Company's satisfaction. PacifiCorp has completed a proof of concept on the proposed solution and is working with manufacturers to address deficiencies.

During this same period, PacifiCorp has evaluated other potential AMS and concluded that alternatives dismissed in the past, mainly due to price and functionality, may now be viable and merit further investigation. The technology area of AMS is evolving quickly and is still maturing. It now appears that two distinct technology paths are developing: **Mesh Network** and **Point-to-Multipoint**. These two communications paths are discussed in more detail below.

The architecture of an AMS encompasses more than just the meter reading functionality. Care must be taken when choosing a communications network—the network must be compatible with the AMS and all potential future smart grid projects, as well as being flexible enough to incorporate open protocols for projects that have yet to be envisioned.

As the first step in this project, it is recommended that the Company develop an AMS strategy that addresses not only metering requirements and the delivery of associated cost savings, but also allows for evolving technology to further mature so that a decision involving all impacted departments can be fully vetted and sequencing with other PacifiCorp technology projects (e.g. replacing the customer service and support system) can be achieved. The joint strategy effort will be led by the Smart Grid department and include the following departments: Metering, Transmission and Distribution operations, Information Technology, Engineering, Demand Side Management, and Telecommunications. The research and analysis work began in 2013 and a strategy will be delivered by October, 2014.

All financial analysis to date indicates a marginal IRR of approximately [redacted] for Phase 1 of the Mesh Network and Point-to-Multipoint migration plans. The operation and maintenance savings for the first full year after implementation of Phase 1 in both migration solutions is estimated at $[redacted] million and $[redacted] million respectively. The decision to pursue this technology has been driven by the desire of the Commission to have PacifiCorp investigate two-way metering technology that can provide smart grid benefits and avoid the risk of stranding assets related to a one-way metering solution.

Network Types and Financial Analysis

PacifiCorp is evaluating two competing advanced metering technologies that have emerged as industry leading designs for two-way advanced metering systems: mesh network and point-to-multipoint communications network solutions. Each solution has unique benefits and drawbacks.

<u>Mesh Network</u>

A mesh network solution would potentially allow PacifiCorp to implement one-way automated meter reading technology during the initial phase of the project. The total capital investment for the initial phase would be approximately $[redacted] million and yield a marginal [redacted]% IRR. The benefits of this solution include:

- Reduced annual meter reading operating costs
- Increased revenue due to more accurate meters
- Avoided cost from replacing existing mechanical meters
- Reduced operating costs from performing remote connect/disconnect functions

In the second phase of the project, the proposed mesh solution meters would operate as a full two-way advanced metering system utilizing the fully installed and activated mesh network. In order to migrate to an advanced metering system (from Phase 1 to 2), a meter data management system and the meter operations software would need to be installed and integrated. A fixed network communications infrastructure would also need to be built out. The estimated capital expenditure for the second phase is, at a minimum, $[redacted] million in addition to Phase 1, and currently yields a [redacted]% IRR. The completed system, phase 1 and phase 2 yield a [redacted]% IRR.

The following table illustrates the functionality and benefits of the mesh network technology. The vertical blue bar indicates the installation of the two-way network as the precursor to

Phase 2. Highlighted below in red are metering-based benefits and functions. All benefits and functions in black are smart grid applications.

Mesh Migration Matrix				
	PHASE 1		**PHASE 2**	**Incremental**
	Advanced Mobile (one-way)	**Communication Network Installation**	Advanced Metering Infrastructure (two-way network)	Integrated Smart Grid (two-way network)
Functionality	All AMR benefits plus: Remote demand reset Hybrid remote service switch TOU upport		Interval Data On-demand Reads Outage Detection/Restoration Notification Voltage Monitoring Consumer Data Access Critical peak pricing	Integration of customer-owned renewables Condition-based Asset Mgmt./Maint Conservation Voltage Reduction Distribution Automation Integrated Demand Side Management
What's Needed	Meter replacement Mobile collection system Software and billing system integration		Network Infrastructure WAN backhaul Meter Data Management (MDM) OMS Integration Billing System Upgrades	Integration with new and legacy systems Analytics Programmatic development and offerings (Solar, EV)
Benefits (Utility)	Reduced O&M No estimated reads Accelerated revenue cycle Improved worker safety, Reduced liability/insurance risk		Improved Grid Awareness (outage/ voltage) Streamlined customer service transactions (e.g. move-in/move-out, high-bill complaint resolution) Network platform for other grid applications (DA, Load Control, DR etc.)	Peak Load Management Improved Grid Efficiency/Reliability Cap Ex Optimization/deferral
Benefits (Customer)	More accurate billing Improved customer service Customer privacy TOU capability		Immediate outage awareness Value-added services to customers	Support for clean energy technologies Enhanced Energy Management Tools
Benefits (Society)	Reduced CO_2 emissions from less vehicles on road		Even fewer utility vehicles on road (reduced carbon emissions)	Cleaner Energy Resource Portfolio Reduced Carbon Footprint

	than manual meter reading			

Point-to-Multipoint Network Solution

The potential point-to-multipoint solution differs from mesh in that it would require a two-way network during the initial phase. The total capital investment for the initial phase would be approximately $[redacted] million and yield a marginal [redacted]% IRR. The benefits include:

- Reduced annual meter reading operating costs (larger compared to Phase 1 of the mesh solution)
- Increased revenue due to more accurate meters
- Avoided cost from replacing existing mechanical meters
- On-demand reads
- Reduced operating costs by performing remote connect/disconnect functions (larger compared to mesh Phase 1)

The following table illustrates the functionality and benefits of the point-to-multipoint network technology. The blue bar indicates the installation of the two-way network as part of the initial phase. Highlighted below in red are metering-based benefits and functions. All benefits and functions in black are smart grid applications.

Point-to-Multipoint Migration Matrix				
	Communication Network Installation	**PHASE 1**	**Incremental**	**Incremental**
		Strategic AMR/AMI (two-way network)	Advanced Metering Infrastructure (two-way network)	Integrated Smart Grid (two-way network)
Functionality		All AMR benefits plus Remote Demand reset Full Remote Service Switch TOU Support On-demand Reads	Interval Data Outage Detection/Restoration Notification Voltage Monitoring Consumer Data Access Critical peak pricing	Integration of customer-owned renewables Condition-based Asset Mgmt./Maint Conservation Voltage Reduction Distribution automation Integrated Demand Side Management
What's Needed		Meter replacement Network Infrastructure WAN backhaul Software and billing system integration	Network Infrastructure Meter Data Management (MDM) OMS Integration Billing System Upgrades	Integration with new and legacy systems Analytics Programmatic development and offerings (Solar, EV)

Benefits (Utility)		Reduced O&M No estimated reads Improved worker safety, Move-in/move-out Fully automated remote disconnect	Improved Grid Awareness (outage/ voltage) Network platform for other grid applications (DA, Load Control, DR etc.)	Peak Load Management Improved Grid Efficiency/Reliability Cap Ex Optimization/deferral
Benefits (Customer)		Accurate billing Improved customer service Customer Privacy TOU capability	Immediate outage awareness Value-added services to customers	Support for clean energy technologies Enhanced Energy Management Tools
Benefits (Society)		Reduced CO2 emissions from less vehicles on road for manual meter reading	Even fewer utility vehicles on road (reduced carbon emissions)	Cleaner Energy Resource Portfolio Reduced Carbon Footprint

Conclusion

It should be noted that *any future phases*, either for mesh or point-to-multipoint, would need additional investments in distribution management software and field hardware to provide the functionality and benefits indicated. Each of those functions, either independently or collectively, must have business cases generated to justify the additional capital expenditure.

Careful consideration needs to be taken when selecting the meter data management system, information technology software, and telecommunications network when designing a two-way advanced metering mode. The information technology interface and telecommunication infrastructure is critical, since it will require meter data integration and a scalable system to provide the flexibility to migrate to other application data needs (e.g. the Energy Imbalance Market project). The cost of migrating to any advanced meter system does not include any costs associated with replacing the customer information and billing system, which will also need to be taken into account.

It is premature to determine which technology is the best option. Both solutions will meet the needs of metering, and provide enhanced benefits that are specific to their own technology, but all other functionality and benefits are contingent on a robust and scalable telecommunications and information technology infrastructure. For that reason, the selection of the correct advanced metering system technology will need to carefully weigh the concerns of all affected stakeholders.

TABLE 1: Metering System Cost Comparison

Meter Reading Systems – Cost Comparison (Oregon)						
Technology	**AMR**	**Mesh AMR**	**Mesh AMI**	**Mesh AMI**	**P2MP AMR**	**P2MP AMI**
Phase		***Phase 1***	***Phase 2***	***Combined***	***Phase 1***	***Phase 2***
Capital Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**Incremental**
Annual Operations and Maintenance Savings	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**Incremental**
IRR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**Incremental**

REDACTED
EXHIBIT B
COMMUNICATING FAULTED
CIRCUIT INDICATORS PROJECT ANALYSIS

COMMUNICATING FAULTED CIRCUIT INDICATORS PROJECT ANALYSIS

Non-communicating faulted circuit indicators (FCIs) have been used for years to visually indicate fault locations on PacifiCorp's distribution lines. Recent advances in communication technology have enabled advanced FCIs, or communicating faulted circuit indicators (CFCIs), that can send alerts to operations centers and mobile troubleshooters, as well as enable the ability to log data for engineering planning and analysis. In light of this new technology, PacifiCorp has begun researching CFCI applications on the Company's distribution system and analyzing the costs and benefits of various implementation schemes.

CFCIs have the potential to improve reliability indices such as the customer average interruption duration index (CAIDI) by reducing the amount of time between the initiation of a fault and its detection and location. The fault location function of a CFCI operates by sending a signal to an outage management system or a troubleshooter, indicating that a fault has occurred and giving its approximate location. This data can be sent as a simple GPS coordinate or other locational data point or it can be incorporated into a more advanced algorithmic system which may be able to pinpoint the potential fault locations more precisely.

Many CFCIs also have the ability to transfer line loading data, temperature and other line parameters, which enables planning and algorithmic waveform analysis which can be used by planners and engineers to optimize circuit design and detect incipient faults.

Engineers at PacifiCorp are currently researching circuits on which CFCIs may prove most beneficial and are analyzing the potential impact of these sensors on reliability indices and planning processes. A preliminary cost/ benefit analysis was conducted to determine the value of applying CFCIs to a number of circuits with higher CAIDIs. In the entire Rocky Mountain Power service territory less than 60 circuits exhibited a positive benefit/cost ratio with seven showing benefit/cost ratios above two.

A survey of the industry shows an average three-phase CFCI kit with software costs near [redacted]. With [redacted]% I/T and miscellaneous costs added in the cost comes to [redacted] per kit. With an average of four installations per circuit and an average CAIDI point valued at $[redacted] the seven highest CAIDI circuits in Utah should result in a net present value of [redacted]. These calculations are based on the CFCIs improving CAIDI values by a conservative [redacted]% and the CFCI equipment proves to have a 10 year lifespan and a yearly maintenance cost of [redacted]% of installation costs.

In light of this analysis, PacifiCorp engineering is in the process of implementing a pilot program in the Rocky Mountain Power service territory in the next twelve months to fully ascertain the benefits and costs of these communicating sensors and to gain experience with the operational elements involved in their application. An update on this project will be included in subsequent smart grid reports.

REDACTED EXHIBIT C
DYNAMIC LINE RATING SYSTEM ANALYSIS

DYNAMIC LINE RATING SYSTEM ANALYSIS

<u>Miners-Platte Dynamic Line Rating Analysis</u>

In 2011, PacifiCorp embarked on a pilot program to install a dynamic line rating (DLR) system on the Miners-Platte 230 kV transmission line located in southeast Wyoming. In the summer this line constrains the entire Western Electric Coordinating Council (WECC) TOT-4A transmission path, due to its static capacity rating. A review of the line topology, construction, and regional climate conditions indicated that the line (and consequently the entire TOT-4A transmission path) could benefit from an increased rating with the implementation of DLR technology.

PacifiCorp is currently in the process of collecting data to analyze the benefits of the installed DLR system. Preliminary analysis indicates that it is possible to increase the line rating on the Miners-Platte line upwards of 54 MW, at which point it will no longer be the constraining link on the transmission path.

A comparison of the reconductoring costs on the 31.3 mile Miners-Platte line ([redacted] to [redacted] per mile) with the DLR technology that was implemented (~[redacted] per mile) shows that DLR provided a cost-effective alternative to line reconductoring.

Some of the benefits the Company expects to accrue from DLR include:

- Facilitation of year round operation of the TOT-4A transmission at its maximum WECC approved rating
- Minimize the impact of static line ratings which unnecessarily reduce transfer capability, thereby improving existing asset utilization
- Reduce the MWh of generation curtailment in order to stay within the maximum WECC approved rating for this path
- Improve renewables integration
- Give the Company experience with integrating dynamic line ratings into its operating procedures

The budget for the project was [redacted] Actual costs for the Miners-Platte line project were:

Component	Actual Costs
Equipment, Materials and External Contracting	[redacted]
Internal Labor	[redacted]
Indirects	[redacted]
Total	[redacted]

Populus-Borah and Kinport Dynamic Line Rating Analysis

In 2012, PacifiCorp began installing dynamic line rating systems on two 345 kV lines from Populus substation to Borah substation and one 345 kV line from Populus substation to Kinport substation, with all lines located in Southeastern Idaho.

Effective July 21, 2011, WECC established the path rating for the Bridger West line at 2,400 MW and the northbound Path C at 1,250 MW. Both paths cannot simultaneously be operated at maximum ratings without additional transmission improvements west of the Populus substation. This project consists of several weak link upgrades west of the Populus substation and installation of a dynamic line rating system, enabling simultaneous rated capacity flows on both paths.

PacifiCorp engineers completed a comparison of the benefits and costs of the modifications that would be required in lieu of the dynamic line rating system installations. The higher cost alternative solutions would require building a fourth series-compensated 345 kV transmission line or reconductoring the existing Treasureton-Brady 230 kV line and looping it into the Populus substation. These alternatives were estimated to cost about [redacted] for the series-compensated 345 kV line and about [redacted] for the reconductoring/loop-in of the older existing 230 kV line. Since these alternatives are much more expensive than the facility upgrades and dynamic line rating system, they were not considered further.

The "do nothing" alternative would mean continuing to operate with existing transmission system limits west of Populus and continuing with current exposure to the Bridger Generation unit tripping. This option does not meet the Company's need to increase west of Populus flows and reduce stress on Jim Bridger generation units.

The DLR installation portion of the project is nearing completion and is expected to be transmitting data by the first part of July 2013. Line data is expected to be captured this summer but will also need to be captured in the summer of 2014 to have enough data to commercially rate the lines with new increased ratings for 2015.

The budget and cost forecast for the project is [redacted]. Actual costs to date for the Populus-Borah and Kinport lines project are:

Component	Actual Costs
Equipment, Materials and External Contracting	[redacted]
Internal Labor	[redacted]
Indirects	[redacted]
Total	[redacted]

Applicability of DLR to Other Locations

It is not a cost-effective or efficient strategy to install DLR on every transmission line, since the limiting constraint may be a different transmission path or a piece of major equipment, such as a transformer or circuit breaker. In these cases, the DLR data may cause operators to increase the capacity beyond the capabilities of the more constrained equipment. In the case of the Miners-Platte project, the topology was particularly well-suited to the application of DLR technology. The benefits of future projects are expected to vary significantly with individual project specifics and should be considered based on system constraints, load growth, line topology, line construction, and climate conditions. As more lines are studied and recommended for DLR, the magnitude of manual intervention to acquire, analyze and interpret the amount of data received from these systems will continue to grow. This will require that a fully integrated DLR system be installed to reduce the administrative and engineering costs. The additional costs to automate DLR have not been analyzed or determined at this time.