PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Smart Grid: Annual Report

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Executive Summary

Smart grid is a loosely defined term that refers to a wide variety of technologies and equipment used by utilities and customers. Generally speaking, smart grid involves a communication network coupled with the power grid. For PacifiCorp, the smart grid definition started with a review of the relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks to enable consumers to respond to system inputs such as price fluctuations and load curtailment requests. A review of these technologies showed that the communications network selected is the most critical infrastructure decision. The 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.

The focus of the smart grid business review will remain on those technologies that can be readily integrated with the existing infrastructure – technologies that do not require major electrical system changes. The technologies chosen for the study were narrowed down to advanced metering systems with demand response programs, distribution management systems and transmission synchrophasors. Technologies not considered for the study include fully redundant ("self-healing") distribution systems, distributed energy systems (including electric vehicles) and direct load control programs.

Each of the components examined have identifiable costs and quantifiable 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 and there is enough theoretical data established for savings opportunities on 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, 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 present benefits to implement a comprehensive smart grid system throughout the PacifiCorp territory appear small relative to the costs. Smart grid technologies do, however, 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.

Questions surrounding the sustainability of any consumer behavior change remain uncertain. To mitigate the costs and risks to PacifiCorp and its customers, it is essential that the technology leaders be identified, and system interoperability and security issues be verified and resolved with national standards. PacifiCorp should allow other electric utilities to absorb the development risk before investing in this technology.

It is recommended that PacifiCorp continue to monitor technological advances and developmental activities 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 in California, Texas and Ontario and a myriad of pilots throughout the country, it is expected that the market leaders will become evident within the next few years. It is anticipated that demonstration projects will reveal the sustainability of large-scale roll-outs.

The Smart Grid – An Introduction

Investor-owned utilities are finding themselves at a crossroads of an evolution involving advanced technologies (collectively referred to as a smart grid), and traditional operational practices. The technologies associated with smart 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 have required that each state review the requirements 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, they have voiced an interest in understanding what the Company's current and future plans are for implementing the smart grid technologies.

The public interest in smart grid has also hit a crescendo due to the marketing efforts by the companies positioned to take advantage of the investments funded by the recently passed ARRA legislation (the "stimulus" package). Inquiries into the Company's ability to provide 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 in the public sector.

The purpose of this document is to define the scope of smart grid for PacifiCorp, identify the suitable technologies that would be required to meet the scope 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. It is not intended to provide a detailed level of understanding or an ideological explanation of the details behind every technology that can be used to migrate to a smart grid system throughout PacifiCorp.

A road map for the future will be generated to align relative start dates for the various components. The start date 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.

The Electric Power Research Institute (EPRI) defines the smart grid as:

- A power system made up of numerous automated transmission and distribution (T&D) 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, 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 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.

In August 2005, Congress passed the Energy Policy Act of 2005. 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 demand response and time-based metering. All states served by PacifiCorp have reviewed and responded to this Act, as required, with no significant effect on the Company’s metering systems or operational standards.

On December 19, 2007, the Energy Independence and Security Act of 2007 was passed and has ushered in a new era in the policy decisions of state regulation commissions as well as electric utility companies within their jurisdictions. This Act is applicable to all electric utility companies; investor-owned, public and municipal. The policy statement contained in Section 1301 of the Act 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 of the Act, Statement of Policy on Modernization of Electricity Grid, defines the “smart grid” and indirectly, smart metering. It is more inclusive than the definition of smart metering found in Section 1252 of the Energy Policy Act of 2005. Section 1301 of the Energy Information and Security Act of 2007 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 demand response, 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.

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.

Acronyms

The electric utility industry utilizes several acronyms that are easily confused with acronyms used in other industries. The evolution of the smart grid has increased the number of acronyms and, as technologies emerge and continue to be refined, several are used interchangeably creating confusion within the industry itself. Table 1 lists several of the acronyms used in this report. Definitions, if necessary, for each will be given in the appropriate section.

Acronym	Name
AMI	Advanced Metering Infrastructure
AMS	Advanced Metering System
CBM	Capacitor Bank Maintenance
CES	Centralized Energy Storage
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
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
TSP	Transmission Synchrophasors
TOU	Time-Of-Use
WAN	Wide Area Network

Table 1 - Acronyms

Defining "The Smart Grid"

For PacifiCorp the smart grid definition started with a review of the relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks to enable consumer demand response programs. As these technologies were reviewed, it was 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, even during the first critical moments of a large scale disturbance to the system.

There are several broad categories within 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, 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 will not be included as part of the 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 2 below. Each of these components will utilize a common information technology and communications infrastructure to gain maximum benefit through reduced duplication of facilities. Technologies not considered for the study include auto-healing distribution systems, distributed energy systems (including electric vehicles) and direct load control programs.

With the large capital investment required to enable these smart grid elements, it is essential that the market leaders be identified, system interoperability be verified and that other electric utilities be allowed to absorb the development risk before PacifiCorp ventures into these technologies. With deployments beginning throughout North America, including California, Texas and Ontario and a myriad of pilots enabled through the recent American Reinvestment and Recovery Act funding opportunities, the market leaders will become evident as the systems begin to mature during 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 2 – Technology Components

Information and Communication Infrastructure

The backbone of the smart grid is the information and communication infrastructure and is critical to the success of the program. The system must be robust enough to not only handle the amount of data generated by the advanced metering system and the intelligent electronic devices (IEDs) deployed throughout the electricity delivery infrastructure, it must also have the intelligence to prioritize and react to the data delivered. Information related to system disturbances or outages must be given fast, preferential handling over lower priority items such as meter readings. 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 comparative purposes when needed to make corrective action decisions to efficiently manage the electricity delivery infrastructure.

Figure 1 portrays a smart grid information and communications architecture that must be developed to fully implement the entire scope of the PacifiCorp smart grid. Note that the transmission synchrophasors are not part of the model. 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.

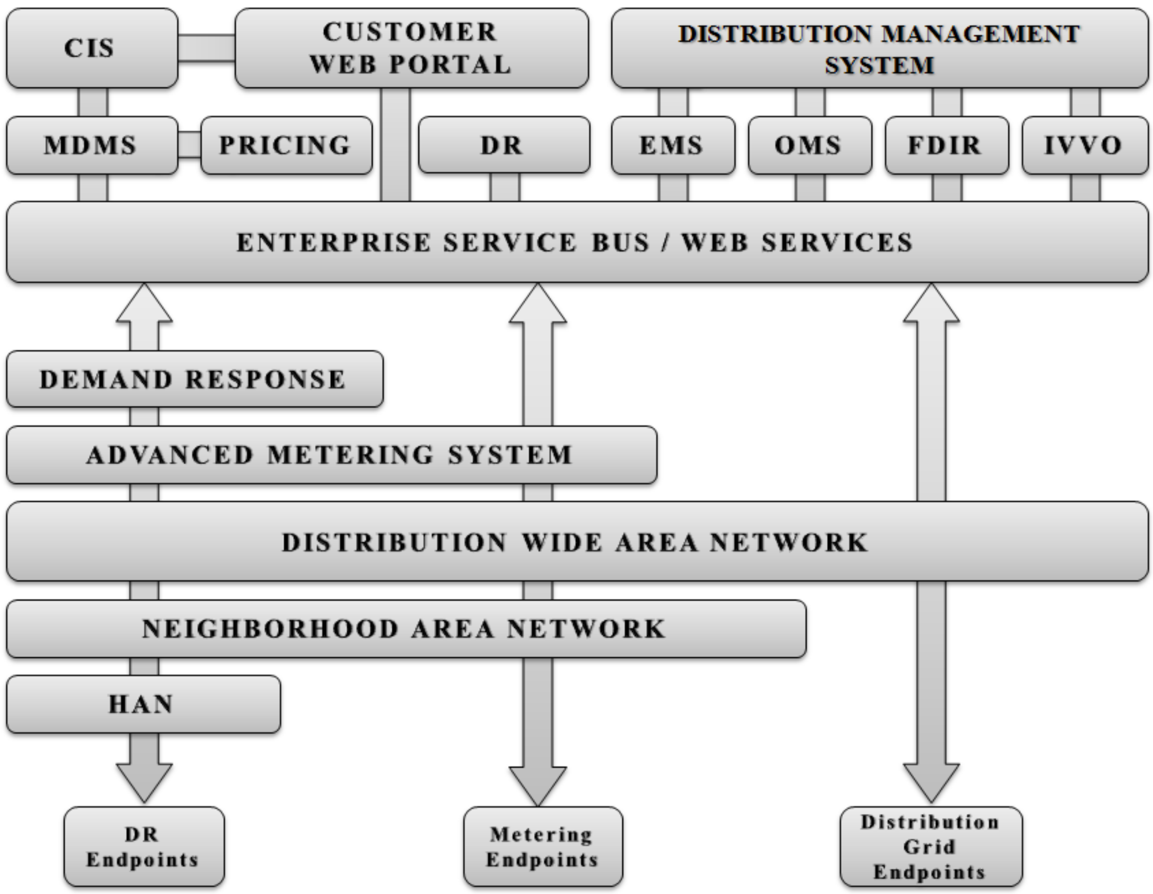

Figure 1 – PacifiCorp Smart Grid Architecture

Communications Network

The 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 geographic expanse of PacifiCorp's service territory, dictates a large, complex and costly smart grid communications network.

The intent of smart grids is to provide improved efficiencies in the production, transport, and delivery of energy. This is 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 imply more measurement points, remote monitoring and management capabilities than exist today. It also requires a greater reliance on reliable, robust and highly available communications.

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 advanced metering systems (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. To reach out to support customer and distribution assets, new wide area networks (WANs) will need to be built out or leased.

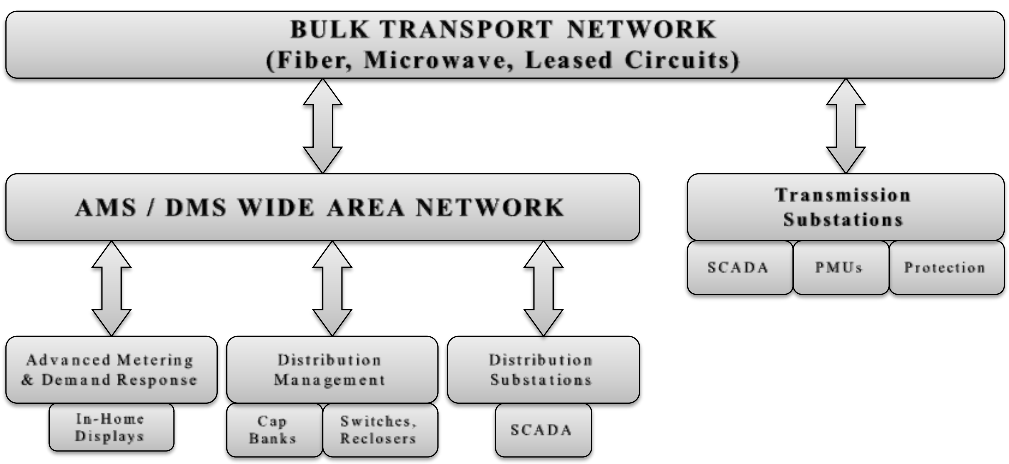

Figure 2 – Smart Grid Communications Network

The vision is to efficiently leverage the long-haul communication assets currently deployed and not create "silos" of purpose-built networks. The key to ensuring this doesn't happen 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 that is being developed by the National Institute of Standards and Technology (NIST).

Advanced Metering System (AMS)

Advanced metering systems (AMS) provide the highest level of meter reading automation and satisfy all requirements for the smart grid system. AMS provides the data required to fully integrate meter reading, demand response, outage management, and distribution management functions. These systems have the capability to offer an “in-home display” of information to customers and integrate direct load control where the utility sends signals to cycle loads (e.g. A/C, water heaters, etc.). Furthermore, these systems are capable of integrating indirect load control where the utility sends pricing signals and consumers can program the behavior of their individual appliances to respond to changing prices.

Advanced metering infrastructures, commonly referred to as AMI, provide the same metering data levels as automated meter reading, or “drive-by” systems, but they provide enhanced capabilities by collecting interval data from all meters. This interval data can be used for time-based rates and critical peak pricing programs, but lack the direct customer notification and integration of in-home displays. These systems can provide additional benefits in the form of outage detection and restoration messages via the system. Demand response programs cannot be implemented directly through most AMI systems. Demand response programs are 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.”

Note that neither home area networks nor in-home displays are a required component of AMI as defined by FERC, although they offer benefits for demand response in addition to those possible with AMI-supported time-varying pricing alone. Also, control of distribution equipment (reclosers, sectionalizers, capacitors, etc.) is not a required component of AMI. In combination, these additional features begin the framework for a “smart grid”.

Automated meter reading (AMR) systems are 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 are the most commonly implemented automated meter reading 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.

The term “AMI” is used routinely 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 advanced metering systems. The functional requirements of the metering system must be known 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. Automated meter reading systems, and most advanced metering infrastructures, cannot be migrated to an advanced metering system without significant costs.

Demand Response (DR)

One of the key requirements to encourage customers to change energy usage patterns is to make the proper pricing signals available that encourages changes in the time energy is utilized. The most common price signals in the industry today are time-of-use (TOU), critical peak pricing (CPP) or peak time rebate (PTR) programs. A combination of TOU/CPP or TOU/PTR pricing programs are the most prevalent and present the greatest opportunity for creating reductions in energy usage during the most critical times when system peaks are present.

TOU tariffs create pricing programs that present to the consumer the real-time or relative price 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, or 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. Critical peak pricing schemes are 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, increases dramatically at the end of the CPP event in an effort to bring the customer’s residence back to a “normal” comfort state. If the CPP event occurs for an extended period of time, the rebound effect becomes more pronounced and can create a new daily system peak higher than what the normal peak may have been. This is an anomaly that does exist, but there have been insufficient studies to calculate the magnitude and overall system effect with any degree of accuracy.

It has been stated that, given the proper pricing signals, consumers will 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. Thus, there is no history that would allow PacifiCorp to understand how much and how long customers will voluntarily participate in a dynamic pricing program for the life of the program.

The PacifiCorp summer peak of 2011 was measured at 9431 megawatts. System daily peaks for this time period are shown in Figure 3. In reality, the ability to forecast the exact time periods of critical peak events is not possible.

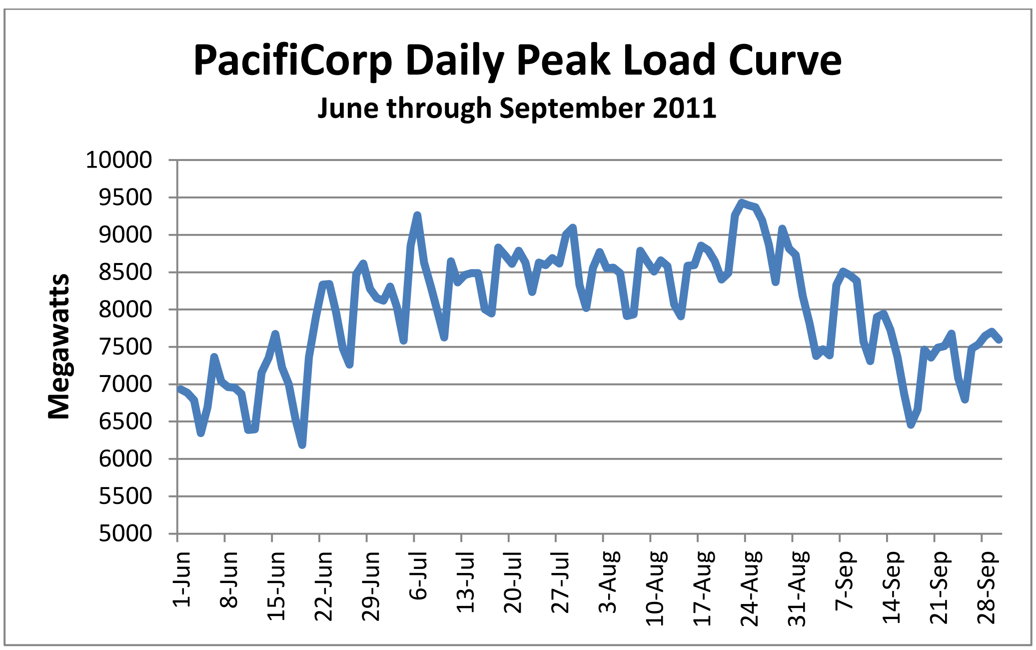

Figure 3 – PacifiCorp Daily Peak Load Curve

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s. The programs are designed 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 2011 PacifiCorp has built a control network of participating customer end use loads of over 700 megawatts, with plans to add an additional 140 megawatts by the summer of 2014[1]. 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 costs. The following Table 3 is a summary of those price schedules by state.

Description	State (Schedule)	Participating customers (Dec. 31, 2011)	Eligible customers (includes participating)	Voluntary or Mandatory
Residential time-of-use or time-of-day pricing(optional)	Utah (Sch. 2)	335	707,283	Voluntary
	Oregon (Sch. 4/210)	1,281	474,810	Voluntary
	Idaho (Sch. 36)	14,290	57,488	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 (Sch.47T)	-	-	Mandatory
	Washington (Sch,48T)	59	59	Mandatory
	California (Sch. AT48)	19	19	Mandatory
	Idaho (Sch. 35/35A)	3	3,472	Voluntary
	Wyoming (Sch.33)	9	9	Mandatory
	Wyoming (Sch.46)	81	81	Mandatory
	Wyoming (Sch.48T)	26	26	Mandatory
	Utah (Sch. 6A / 6B)	2,195	93,262	Voluntary
	Utah (Sch. 8)	274	274	Mandatory
	Utah (Sch. 9 / 9A)	158	158	Mandatory
	Utah (Sch. 10/TOD [1]op	251	2,837	Voluntary
	Utah (Sch. 31)	4	4	Mandatory
	Oregon (Sch. 23 / 210)	274	74,821	Voluntary
	Oregon (Sch. 41 / 210)	58	5,033	Voluntary
	Oregon (Sch. 47)	5	5	Mandatory
	Oregon (Sch. 48)	211	211	Mandatory

Table 3 – Summary of Price Schedules by State

[1] LC 52 - PacifiCorp's Revised 2011 Integrated Resource Plan Action Plan, January, 2012.

Moving from site-specific investments in demand response 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 home area networks 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 their Home Area Network (HAN). In-home displays range from simple plug-in and battery operated in-home displays equipped with three levels of indication via green, yellow and red lights to very sophisticated displays that interface with the customers' home area networks. The simple display warns the customer of an upcoming critical peak event, and the resultant increase in energy prices, with the yellow indicator. This "yellow light" warning allows the customer time to reduce their load prior to an increase in energy prices. The red indicator light remains on during the event timeframe. When pricing structures return to normal on-peak or off-peak state, the indicator light reverts to green.

Home area networks enable the customer to leverage the real-time information received via the advanced metering system into automated actionable tasks that can reduce their energy consumption at peak times as well as enabling overall energy conservation. The advanced metering system provides for transmission of 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 home area network, more sophisticated communicating devices are required to allow the customer to program automatic actions to pricing signals and critical peak events. Home-area networks 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 become critical to long-term success as distribution systems become more sophisticated. A distribution management system (DMS) provides the utility with a variety of advanced analytical and operational tools for managing complex distribution systems. A DMS integrates several systems and functions that are currently operated independently in today's environment, specifically:

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

When integrated with an IVVO functionality, a distribution management system can manage voltages to minimize line losses and energy needs while optimizing the delivery of energy 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 increases the efficiency of the system.

Distribution management systems create 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 distribution management system provides distribution engineers with near real-time system performance data and historical performance metrics. This decreases the 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.

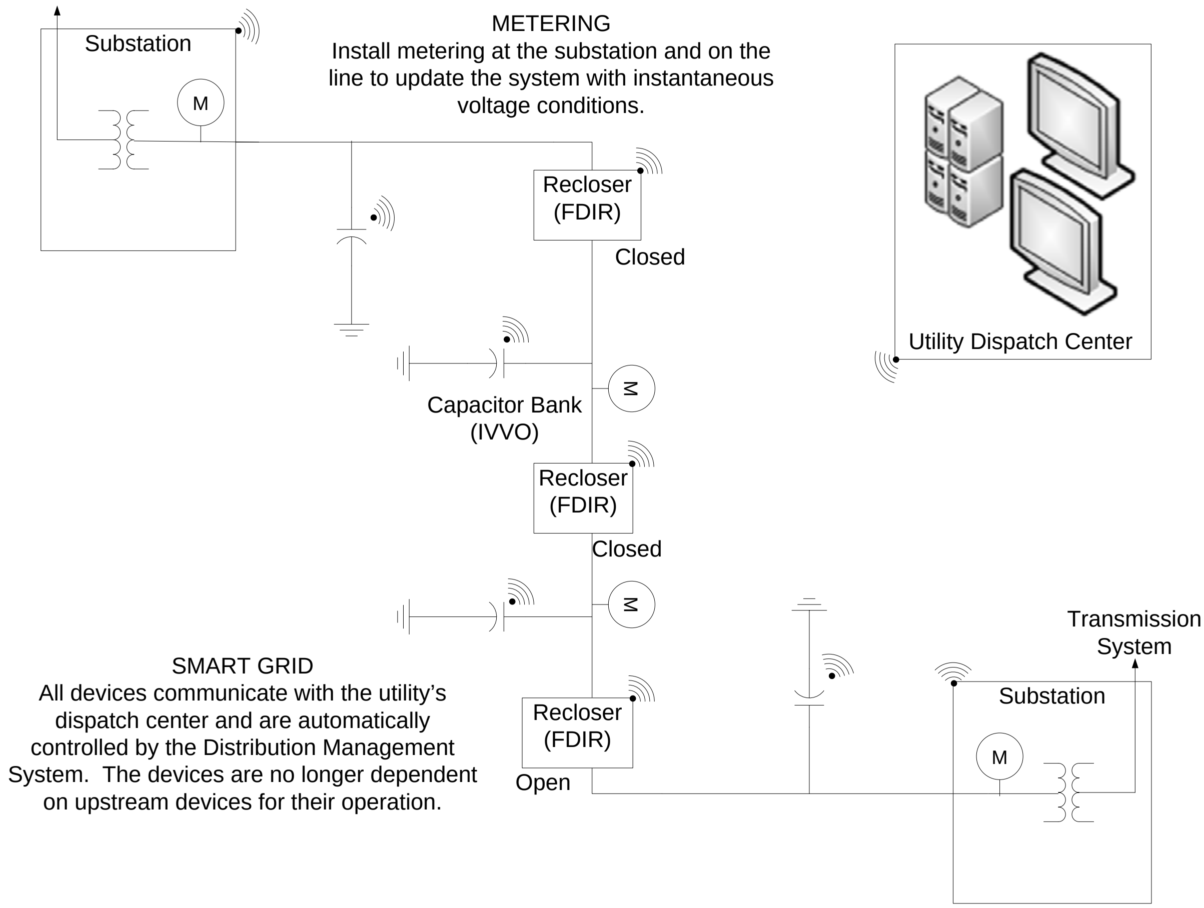

Figure 4 – Generic Distribution Management System

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 the interactive volt-var and fault detection, isolation and restoration activities:

- Monitor unbalanced load flow and determine if there are any operational violations for normal state and reconfigured distribution feeders.
- Determine the optimal position 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 possible location(s) of faults.
- Analyze the system during faulted conditions and determine the redistribution of the 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 interactive volt-var optimization or fault detection, isolation and restoration 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 distribution management system that will incorporate the emerging technologies for 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. 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 line length, impedance and loading, and, if not properly managed, will degrade to levels below the allowable ANSI limit. To keep voltages above the minimum level, 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 consideration and design parameters used for this decision are complex and will not be discussed in detail other than to state that power factor, voltage levels and circuit loading must be considered.

An (IVVO) program utilizes strategically placed distribution voltage regulators and capacitor banks for voltage and power factor management, reducing the line losses due to reactive current. With real-time communications installed at each device, regulator and capacitor behavior can be optimized for goals such as voltage reduction, load reduction or loss reduction. The utility selects the appropriate goal in real-time via a module in the DMS.

In a traditional distribution system, downstream device behavior 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 may not be able to maintain satisfactory voltage levels. The DMS actively manages the voltage levels and power factor and adjusts the line devices independently to produce an optimized voltage profile across the distribution system. This optimized voltage profile 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 demand and energy. 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 line voltages to the lower portion of ANSI Range A.

A utility 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 advanced metering system 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.

CVR Pilot Project

PacifiCorp's detailed CVR analysis began in Washington as a response to the 2006 voter-approved Initiative 937, codified as RCW 19.285 in Washington, which calls for regulated utilities to pursue distribution efficiency savings. PacifiCorp worked with the Washington

Utilities and Transportation Commission's Demand Side Management Advisory Group to define the pilot's scope and cost recovery mechanism in order to ensure compliance with the state's requirements. This was critical in choosing the appropriate investment level for the pilot, and in settling on an appropriate method to measure and verify energy savings.

In 2012 PacifiCorp initiated a four-circuit CVR pilot in Washington State. The four circuits were selected from a group of nineteen circuits that were studied in detail for available cost-effective energy savings. PacifiCorp is continuing its Washington analysis with the study of an additional 25 circuits. Combined with the findings from the pilot project, the Company will use the study results to scope and budget any cost-effective, reliable and feasible distribution efficiency projects in Washington. It is anticipated that up to ten years may be necessary to complete all projects in Washington.

The first study suggests that the pilot should produce savings of 828 MWh/year. 753 MWh of the savings comes from customer use and 75 MWh from improvements to the efficiency of the Company's distribution system. In 2013, the Company will report to Washington the energy saved by the 2012 pilot in accordance with the Simplified Measurement and Verification Protocol approved by the NW Council's Regional Technical Forum (RTF). The RTF is revising its CVR protocols in 2012 which may affect measurement and verification requirements for future projects.

Engineering analysis is very costly and the energy savings can be difficult to measure with confidence. In general, the Company has found that its existing voltage management and system improvement practices are much better than assumed by some regional and national estimates. This has reduced the level of cost-effective savings available with additional voltage reduction measures. The Washington pilot is expected to provide the Company with additional knowledge needed to determine where CVR work is justified.

Capacitor Bank Maintenance

Capacitor banks are visually inspected typically 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 manual inspection, which will help reduce 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.

PacifiCorp has identified several potential risks of CVR and IVVO implementation, based on recent industry research and utility pilots.

- 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, as the additional savings provided by capital improvements, such as the addition of line regulators and capacitors, most often are not cost-justified.
- Projects are often prioritized on cost-effectiveness, which introduces the risk of postponing more cost-effective improvements in locations where IVVO or CVR projects are mandated.
- 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 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.

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 smart 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 generation: demand response programs and centralized energy storage.

Centralized energy storage 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. Electrical battery and flywheel energy storage are two emerging technologies that show significant promise for widespread application in the utility industry.

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-ions batteries remains prohibitively expensive. Flow batteries are touted by some as the leading option for practical, utility-scale, high-capacity electricity storage. 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. 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, this paper will use battery storage 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 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 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 concerning issues that would need further detailed evaluation.

Flywheel energy storage works by accelerating a rotor (flywheel) to a very high speed and maintaining the energy in the system as rotational energy. When energy is extracted from the system, the flywheel's rotational speed is reduced as a consequence of the principle of conservation of energy; conversely adding energy to the system results in an increase in the speed of the flywheel. Such flywheels can come up to speed in a matter of minutes, much more quickly than some other forms of energy storage. Flywheel energy storage systems are also referred to as electromechanical battery systems as their ability to respond quickly to energy demands are similar to chemical battery systems.

PacifiCorp, in collaboration with EMB Energy Inc., is working towards testing and integration of a flywheel energy storage technology for electric power systems. The proprietary flywheel design is expected to drive down the unit price of flywheel-based electrical storage. Once development of a cost effective energy storage plant is clearly proven and demonstrated, it is PacifiCorp's hope that flywheel technology will become a valuable tool in managing intermittent renewable energy and assisting in frequency control.

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 practical 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 into the Company's connectivity model, inform the Company that an outage exists and allows for the dispatch of personnel to manually identify the location and restore service to areas outside the fault zone. When appropriate amounts of data are received from customers, intelligence within the current outage management software can make assumptions as to where a fault may have occurred.

To accelerate service restoration times, the integration of intelligent electronic devices (IEDs) in distribution line equipment (specifically reclosers, sectionalizers and faulted circuit indicators) provide 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. 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 shortening the outage time.

Transmission Synchrophasors (TSP)

The existing PacifiCorp transmission system relies on many electronic elements to insure 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)."

PacifiCorp uses the term RAS and will continue with that terminology throughout this report.

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 off line 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 for 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. 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. PMU deployment is dependent on a wide area network of sufficient geographical coverage, bandwidth, reliability, security and latency to enable PMU functions. Specific data processing and decision logic are required for operations.

A wide area network 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. Additional research is needed to implement dynamic ratings which could, in theory, 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.

Synchrophasor Demonstration Project

PacifiCorp is participating in the Western Electricity Coordinating Council (WECC) Western Interconnection Synchrophasor Project (WISP) 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 $800,000 of 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.

The goal of the WISP program is to increase the coverage of PMUs throughout the west, implement a new secure, stable, high performance wide area network (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 evolving disturbances on the western bulk electric system and take timely actions to avoid wide-spread system blackouts. The system 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.

PacifiCorp is currently working on the installation of synchrophasor data communication equipment at five transmission substation locations in the Company's eastern service territory. Data from the separate substation locations will be communicated to a phasor data concentrator (PDC) which has recently been installed at a Company facility in Salt Lake City. The PDC collects and archives real time data streams from remote sites and transmits the real time data to WECC in Vancouver, Washington. The substation projects are progressing well, with three of the five substations (Camp Williams, Jim Bridger and Wyodak) streaming synchrophasor data information to the WECC location. The additional two transmission substations are scheduled to have synchrophasor equipment installed and streaming data to WECC by the end of 2012.

The overall WECC synchrophasor project - which includes synchrophasor installations at a number of northwest utilities - is scheduled to be completed by March of 2013.

Dynamic Line Ratings (DLR) Projects

PacifiCorp has identified two locations within its transmission system where using real-time dynamic thermal line ratings (DLR) systems will be beneficial. Company standards are currently used to rate lines using two different ampacity ratings: a static winter rating and a static summer rating. Installing DLR systems on these lines will allow the Company to monitor the lines for potential loading to maximize power flow based on real-time ambient local conditions instead of the static seasonal ratings.

The first DLR equipment installation will be on the 31 mile long PacifiCorp 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. The 345 kV lines have 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 involved. The key benefit of DLR technology is to maximize 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 has 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 installed load cells, and solar and air temperature readings from installed measurement equipment.

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.

The 230 kV Miners-Platte line project is currently in the test phase and is on track to be fully operational during the summer of 2012, however an approval process must be undertaken with WECC to commercially operate the line using dynamic ratings. The approval process is scheduled to be completed by March 2013. The multiple-line 345 kV project is currently in the engineering phase and is scheduled to be operational and completed by the spring of 2013.

Technology Dependency

Many of the technologies required to migrate the existing electrical system to a 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 in any program analysis. To harvest 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” capacitors and line regulators. Figure 5 illustrates the technology dependencies for the PacifiCorp smart grid. The illustration shows that the smart grid must be built from “the top down” and along the paths indicated to build a functional system. The only exception is the transmission synchrophasor system which can be built out independently of the others.

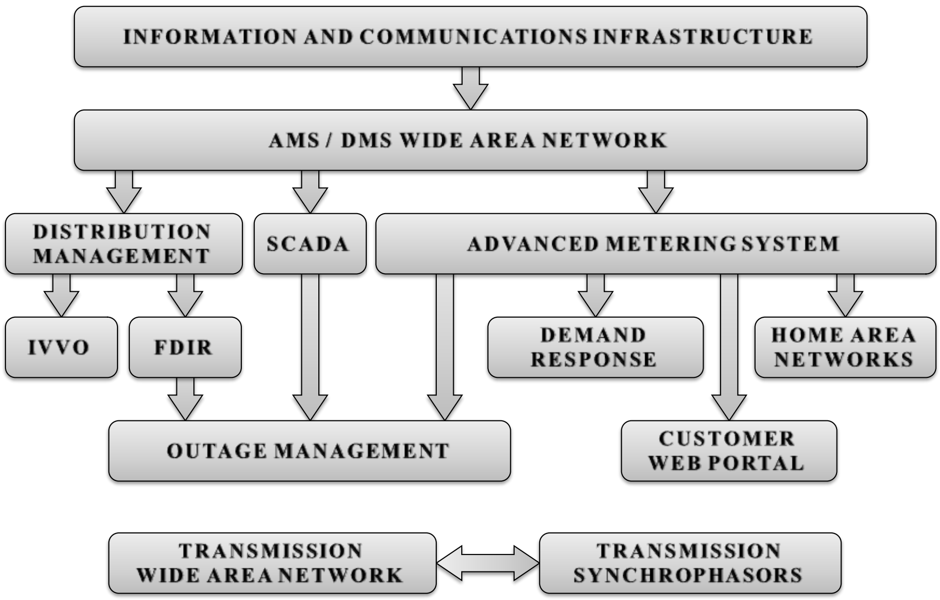

Figure 5 – Smart Grid Technology Dependencies

Challenges and Risks

While there are many upsides to the smart grid, there are many challenges involved in its deployment and the future operations of the electric system. Some of these challenges relate to integration of communication standards (interoperability), ensuring proper security for devices, systems and customers, modifying communications with customers and the impact that disruptive technologies may have on the electric distribution system.

It must be recognized that the electric system in place today was a result of an expansion that was predicated upon economics; as such, the system is engineered for low costs, with redundancy and reliability a lower priority. As growth occurred, that fundamental design precept has not significantly altered. Some advocates maintain that customer engagement is more important than costs. Thus, the fundamental economics are no longer the most critical aspect of the system; rather, the ability for the customer to engage with the electric delivery system is of higher priority. This shift 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 further advancements.

Interoperability Standards

The current lack of interoperability standards risks premature obsolescence of equipment and software installed prior to widespread adoption of such standards. As electric utilities continue to expand existing infrastructure or begin implementing 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 Energy Independence and Security Act of 2007 specified that the Department of Energy champion this effort. The DOE authorized the National Institute of Standards and Technology (NIST) to develop uniform protocols that facilitate information exchange between smart grid devices and systems. 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 Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0). NIST has cautioned that "as they mature, these standards are undergoing revisions to add new functionalities to them, integrate them with legacy standards, harmonize them with overlapping standards, and remedy shortcomings that are revealed as their implementations undergo interoperability testing." To this end, the NIST framework endeavors to utilize the reporting and experiences of ARRA (the American Recovery and Reinvestment Act of 2009) grantees to work with standards development organizations and standards setting organizations to improve the foundational smart grid standards.

The smart grid initiatives that have evolved over the past few years have given birth to an incredible array of new markets and opportunities based on innovative technologies one probably couldn't have imagined at the outset. That point also stresses how important interoperability standards are to a functional, reliable smart grid.

Stakeholders who are not monitoring the NIST activities risk having current investments becoming 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 not even 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 proven to deliver expectations.

Security

The smart grid increases the amount of intelligent data to a level never before seen in the electric 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 at this time. North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) reliability standards were designed to protect the bulk power system against potential cyber security attacks. Yet, these standards do not 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.

Customer Communications

The smart grid opens a whole new channel of communication between PacifiCorp and its customers, but this new communication channel is fundamentally different from the past. 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 to inquire about their charges-to-date. For the customer to maximize their experience with the evolving technology and to understand the actions they need to take to realize the benefits of advanced metering is an important element of a 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 an incredibly daunting prospect with a large potential for unforeseen challenges that can result in significant cost overruns.

Another challenge that PacifiCorp will face is customer recruitment. Preferably, demand response (DR) programs should 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 demand response 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 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 demand response equipment installation company, and various demand response communication systems.

PacifiCorp will also need to re-examine how customer service is provided to customers during deployment and after the advanced metering system 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 the customer concerns. This includes performing customer education needed to increase the understanding of smart metering and to reduce the fear and distrust of the 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 answer and 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.

Metered 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, demand response events, verification and reporting of energy saved, etc.) the potential enormity of the challenge becomes clear.

To illustrate, every day the advanced metering system operations team must support:

- More than 4,000 meter exchanges per day during deployment
- More than 2,000 customer moves per day (based on 25 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
- More than 45,000,000 meter reads per day (assuming one-hour interval data)

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

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 evident.

Distributed generation requires the measurement of electrical energy in both directions. Energy delivered and energy received by the electric utility must be measured to provide the appropriate billing charges and credits for energy consumed and energy 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. However, this increase in meter cost is not reflected in the economic analysis of PacifiCorp’s smart grid program.

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, proving that rooftop PV systems on this circuit 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.

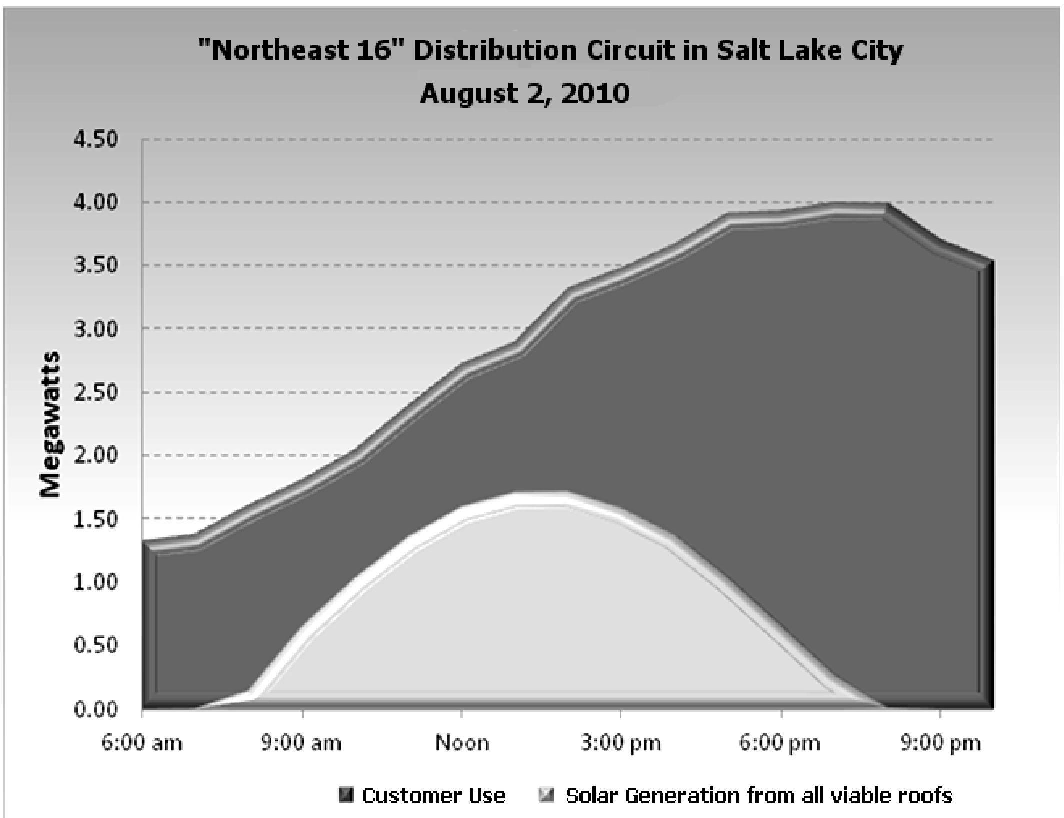

Figure 6 – Daily Peaks for Solar Energy Study

<u>Plug-In Electric Vehicles</u>

Plug-in electric vehicles are expected to become more widely accepted as the technology advances and the purchase price becomes 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. Future battery technologies and plug-in electric vehicle enhancements may lead to utilizing plug-in electric vehicles for vehicle-to-grid energy supply for demand response. 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 and transmission system or the customer's 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 mass scale introduction of electric vehicles occurs, the whole definition of on-peak and off-peak energy usage will change. These issues are being handled by a separate group within PacifiCorp and will not be addressed herein.

Economic Review

Each of the components identified for PacifiCorp's smart grid have identified costs and quantifiable benefits that were used to determine the rough potential of investing in those technologies. Whereas there does not exist any proven costs or savings for all of the components, there does exist qualified estimates that can be used to gauge costs and enough theoretical data established for savings opportunities on 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. As actual and time proven data becomes available, the cost and savings assumptions will need to be updated to 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 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 added generation and off-system energy purchases and are categorized into generation savings.

Consumer-based savings are directly attributed to changes in consumer energy-use behavior and are unproven benefits with questionable sustainability. 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 and critical peak pricing structures, consumers are unlikely to have the incentive required to make the behavioral changes required to bring about the benefits of a smart grid. Recommendations or models for time-of-use pricing structures are very complex and will require significant levels of study and debate to arrive at the proper design. Thus, pricing models will remain outside the scope of this document.

Measurement of consumer-based savings can only be estimated as a reduction in generation requirements and measured by the associated marginal pricing. Additionally, company-based savings could be estimated as a reduction in capital requirements for electrical infrastructure expansion and replacement. However, these savings are only temporary in nature as customer load growth drives 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 continue to be vendor selection, home area network protocol and interoperability of components. Additionally, commission approval of new and revised time-varying rate structures and customer participation in these rates is a key component for success.

As with any new technology, employee training and business process changes must occur to gain the expected benefit. Technology specific training has been identified and included within the individual technology cost calculations. Costs for business process changes have not been fully determined, but a reasonable estimate had been included for an accurate picture of the cost of smart grid. The benefits of the AMS results 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.

Additionally, 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 have recently been converted to automated meter reading systems and others may be in the future 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 completed when a detailed analysis is done and after the risks of the assumptions are less. The detailed analysis will be completed prior to any regulatory filing for advanced metering or smart grid.

Demand Response

The advanced metering system presented in this business review is the enabler for a price responsive demand response 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 rates would require regulatory and/or legislative support in all Company jurisdictions and be supportive of:

1) mandatory TOU and CPP for residential and small commercial customers, and
2) changes in the current manner in which utility costs are recovered. A shift to time-based pricing would require a decoupling of volumetric sales from the recovery of utility costs.

Absent this shift in environment, the benefits assumed in this review for demand response are unlikely to be realized. The benefit assumptions 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 demand response pilot programs, while informative, is insufficient to accurately predict results on a larger scale, across multiple jurisdictions, and in a low retail cost 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 two 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 demand response and energy use reductions. To help improve response to CPP events, PacifiCorp would offer a coupon to customers 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 roll out of the tariff, purchase and distribution of basic CPP indicators, notification and control systems, equipment coupons and customer education. A majority of these costs would be spent through 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 more sophisticated IHD's 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 demand response 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 demand response 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 demand response on a broad scale would be beneficial.

Adjustments were made to the costs and benefits of demand response for the residential and small commercial load management programs currently in place[2] and operated by PacifiCorp today. The costs of these programs were netted out of the cost and benefits of the broader demand response applications envisioned in a Smart-Grid enabled environment. Whereas demand response 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 very limited amount of experience or data available on which to assess the requirements for customer education 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

[2] 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.

programs throughout PacifiCorp's service territory, a conservative cost of $12 million has been included. This value 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 and 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 over the lifetime of the distribution system. The cost to migrate to smart grid has been mitigated as the existing line equipment will require that only the control panel be upgraded to allow for the required two-way communications. In addition to the existing line equipment, and to create a smooth, level voltage profile, additional capacitor banks will be installed and controlled by the DMS. 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 fault circuit indicators and automated field switching devices will provide for additional operational benefits from 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 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.

Other Companies Pursuing Smart-Grid Technologies

Oncor Electric Delivery, serving over 400 communities in the state of Texas, has a number of smart grid projects in the works. Between 2007 and 2012 Oncor's advanced metering system (AMS) and infrastructure (AMI) was rolled out to 3.4 million customers. This metering infrastructure allows a centralized database to record electric consumption every 15 minutes, which makes implementation of time-of-use pricing plans possible. Customers have in-house displays which provide real-time electricity use feedback, which can in turn help them make energy-savings decisions. TXU Energy, also located in Texas, recently implemented a program that warns customers with smart meters when their current electricity usage could lead to a bill above a set threshold, and other utilities may soon follow suit. The AMS also allows customers to utilize home area networks (HANs) using Zigbee technology to program and control smart appliances within the house. Oncor requires third-party manufacturers to test devices with Landis+Gyr, the manufacturers of Oncor's metering system, to ensure compatibility. Other smart grid applications at Oncor include: Siemen's Distribution Management System, Spectrum Power

SCADA and DNA products; Intergraph's outage management system, Inservice; broadband over power line (BPL) technology; and distribution automation (DA) upgrades.

Portland General Electric, headquartered in Portland, Oregon, has 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 13kV 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.

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.

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 2012 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 discussed previously in the report. For example, the savings associated with demand response cannot be achieved without the investment in information technology, metering/distribution wide-area network and the advanced metering system. 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 the economic value of the individual components must be considered and a determination of the maturity of the technology be ascertained. Due to the co-dependency of some of the components as stated earlier, 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 4 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 4 – 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 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 implementation 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 to ensure the financial integrity and compliance with emerging standards are maintained.

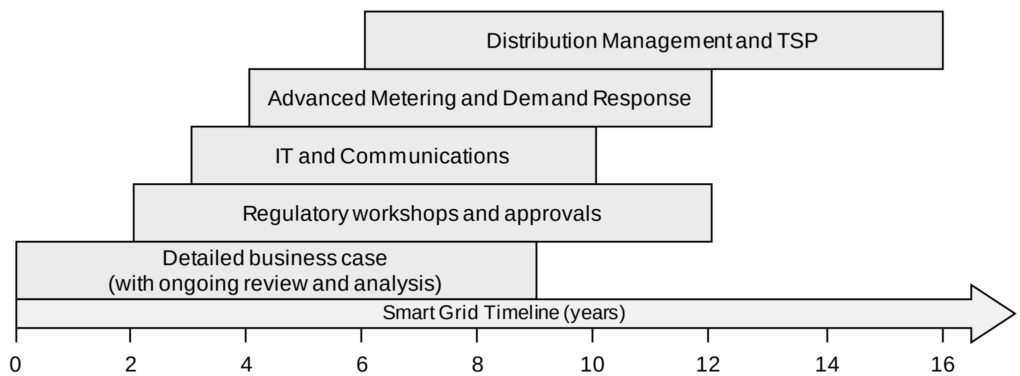

Figure 7 – Smart Grid Roadmap

Conclusion

The present economics to implement a comprehensive smart grid system throughout the PacifiCorp territory are forbidding. Smart grid technologies do, however, 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 demand response are unproven and based on optimistic assumptions regarding the number of customers who will change their energy usage; 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, system interoperability be verified and other electric utilities absorb the development risk before the Company invests in this technology.

It is recommended that PacifiCorp continue to monitor the activities throughout the nation as more advanced metering and other smart grid related projects are developed. This will allow for more precise estimates for both costs and benefits. With large scale deployments progressing in California, Texas and Ontario and a myriad of pilots throughout the country, the market leaders will become self-evident within the next few years and will demonstrate whether sustained demand response for large-scale roll-outs is supported by the precedent pilot programs.