Final Report

Distributed Energy Resiliency Study

prepared for the
Oregon Department of Energy

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List of Appendices

List of Tables

List of Figures

EXECUTIVE SUMMARY

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Introduction

This Report's overarching objective is to identify opportunities to improve energy resilience through the design and integration of distributed renewable energy investments into the existing energy network. This study considers how new technologies, including renewable energy resources, could provide local energy generation to communities and emergency service providers during energy emergencies, when their energy network supply may possibly be disrupted.

The Oregon Department of Energy (ODOE) will use the information that is provided by this Project to support its Energy Assurance Plan (EAP).

Highlights of this Report are briefly noted below. For a more complete understanding of such items, this Report should be read in its entirety.

Access to Information

This Report is broadly based on information, data, and reports that were provided by various organizations, including:

- Bonneville Power Administration (BPA)
- Idaho Power Company (IPC)
- Oregon Department of Energy (ODOE)
- Oregon Department of Transportation (ODOT)
- Oregon Public Utility Commission (PUC)
- PacifiCorp
- Portland Gas and Electric (PGE)
- United State Department of Energy (U.S. DOE)
- U.S. DOE Energy Information Administration (EIA)
- U.S. DOE National Energy Technology Laboratory (NETL)
- Western Electricity Coordinating Council (WECC)

All such information is considered to be in the public domain. Confidential information was not provided or utilized.

Critical Facilities

Renewable Resources

Section 1 identifies the full spectrum of Oregon's existing and planned renewable resources. However, not all of Oregon's wind resources qualify as critical in an energy assurance context. In fact, there are reasons why none of Oregon's renewable resources are critical, including:

- Renewable resources (most notably wind and solar) provide energy but not capacity.
- Renewable resources cannot be dispatched and, therefore, are less likely to be useful during an energy crisis.
- During a large-scale emergency, the complete restoration of the electric grid may take hours or even days. That period of time is sufficiently long to observe considerable variation in capacity and energy from renewable resources.
- During a large-scale electric emergency, prevailing utility operating practices are to bring renewable resources back on-line after all other resources are dispatched.

Hydroelectric Resources

Hydroelectric resources are responsible for approximately 42 percent of the electricity consumed in Oregon. The dams of special importance include John Day, The Dalles, Bonneville, and McNary, which are all located along the Columbia River and collectively account for over 6,000 megawatts (MW) of capacity, or nearly 80 percent of Oregon's hydroelectric energy. Hypothetical events that affect the river (e.g., drought, floods, terrorist attacks, federal court decisions regarding salmon restoration) could result in the loss of approximately half of Oregon's electric supply.[1]

Conventional Resources

Conventional resources (excluding hydroelectric) account for approximately 54 percent of Oregon's electric supply with natural gas (14 percent) and coal (34 percent) ranking highest, on the basis of historical energy usage. The most critical non-hydroelectric conventional plants are Boardman (coal), Hermiston, Beaver, Klamath, Port Westward, and two Coyote Springs facilities (all natural gas).

Electric Transmission

All electric transmission lines in the Pacific Northwest at or above 345 kilovolts (kV) should be classified as being critical to Oregon. BPA is responsible for 5,568 miles of lines throughout the Pacific Northwest at or above 345 kV. While some of BPA's lines are outside of Oregon, the interconnected nature of the transmission system still requires such lines to be classified as being critical. BPA's regional 230-kV and

[1] It should be noted that the regional electric transmission and generation systems are highly interconnected. Some of the hydroelectric energy produced by plants that are located along the Columbia River is not intended for Oregon's use and other interconnected plants could be utilized as replacement energy.

287-kV transmission lines should also be considered to be critical, in the absence of any detailed determinations to the contrary. In addition, BPA's high-voltage substations should also be included. A delineated list of such lines and substations is not available due to security concerns.

Electric Distribution

Currently, there are no distribution lines that are considered to be critical from a regional or statewide perspective. Specific distribution lines that serve emergency service providers are critical, but cannot be delineated due to the absence of pertinent information.

Smart Grid and Advanced Metering Infrastructure

Currently, Smart Grid and Advanced Metering Infrastructure (AMI) are not widely utilized in Oregon, which precludes such assets from being considered a critical asset.

Blackstart Operations

A large-scale emergency in Oregon could cause the electric transmission and generation grid to become completely de-energized (e.g., dark). Such events would be followed by a blackstart start condition whereby certain generating units are called upon to initially re-energize the grid. While the identities of specific blackstart generating units have been withheld by Oregon's electric utilities for reasons of security, they are likely to include larger hydroelectric plants.

Emergency Service Providers

The energy requirements of certain service providers are considered to be of paramount importance during emergency conditions. The entities of highest priority include:

- 911 dispatch centers
- Airports
- Assisted care living facilities (e.g., senior citizen facilities, handicap persons facilities, homes of the disabled)
- Communications service providers (e.g., voice, data, Internet, television, cable television, radio)
- Correctional facilities (e.g., jails and prisons)
- Electric utilities (critical facilities such as warehouses and maintenance and repair centers)
- Emergency Operations Centers (EOC)
- Emergency shelters (e.g., designated locations such as schools, religious institutions, recreation centers)
- Fire stations

- Petroleum Distribution Terminals
- Gas stations (if required to serve the petroleum needs of other emergency service providers)
- Health care (e.g., hospitals, ambulance services, and clinics which contain emergency room facilities)
- National Guard
- Oregon Department of Transportation (ODOT)
- Other essential county, state, and federal departments
- Police stations
- Public Works (e.g., water, wastewater, street maintenance, traffic signals at priority intersections)
- Railroad operations and crossings
- Red Cross
- Schools (short-term, until all students return home)

Providing reliable and resilient electric service to the above entities during a large-scale emergency is a critical matter that requires the PUC's attention. The PUC works with utilities to ensure timely restoration of the power grid during emergencies. Energy related characteristics are discussed in Section 2.

Vulnerability and Risk Assessment

Section 3 contains an assessment of the vulnerabilities and risks that are associated with Oregon's key energy categories, as summarized in the following table. Overall, findings indicate that hydroelectric resources are most critical to Oregon.

Table 1
Energy Sector Criticality and Vulnerability

CATEGORY	Market Dominance/ Relative Capacity	Number of Customers Served	Strategic Location	Seasonal Vulnerability	Degree of Redundancy	Historical Evidence of Disruption
Electric Generation (Conventional without Hydroelectric)	Low	Low	High	High	Medium	Low
Hydroelectric Generation	High	High	High	High	Medium	Low
Renewable Electric Resources	Low	Low	High	High	Medium	Medium
Electricity Transmission	Low	Low	High	Low	Medium	Low
Natural Gas Transmission/ Pipelines	High	High	Low	High	High	Low

Key issues that confront critical assets are found to include the following:

- **Critical Infrastructure Protection (CIP) and terrorist attacks:** Critical infrastructure is defined to be assets that are so vital to Oregon, that their incapacity or destruction would have a debilitating impact on the state's security, economy, public health or safety. Large hydroelectric generating facilities and associated high-voltage transmission lines are considered critical to Oregon as they serve a significant percentage of state's electricity requirements. The U.S. DOE conducted an audit of BPA's critical infrastructure in 2010 and discovered that BPA did not, for the most part, implement a major physical control system (e.g., electronic perimeter intrusion motion detection and alarms).
- **High levels of precipitation or runoff:** Periods of high spring runoff can have a significant impact on hydroelectric power and, thereby, cause a reduction in the utilization and pricing of renewable resources, as evidenced in April-May 2011.
- **Seismic activity:** Earthquakes can significantly impact Oregon's electric, natural gas and petroleum resiliency. The Oregon Department of Geology and Mineral Industries (DOGAMI) is evaluating the impacts of earthquakes in Oregon and its report should be reviewed for additional information.[2]
- **Weather:** Severe windstorms have historically impacted Oregon's electric grid, thereby causing widespread curtailments in electric service.

[2] "Oregon State Energy Assurance Plan", Oregon Department of Energy, Oregon Public Utility Commission, March 2011.

Integration of Renewable Energy and Smart Grid Technologies

Section 4 contains a discussion of the technical issues, which confront the integration of renewable resources, the role that Smart Grid technologies could play in addressing such matters, and the benefits that can be provided to Oregon's constituents. Some of the potentially more notable benefits include:

- **Improve electric reliability:** Smart Grid technologies can improve the reliability of electric service by reducing the duration of outages and the number of customers without service.
- **Reduce electric production costs:** Providing consumers with real-time electric pricing information and alternative tariffs (such as critical peak pricing) can yield reduced electric costs to consumers and the cost of electricity production.
- **Reduce peak electric demand:** The amount of electricity demanded by Oregon's consumers varies greatly throughout the year, with peak electric demand occurring during the hottest and coldest points of time. Smart Grid applications can communicate the real-time price of electricity to consumers, especially during periods of peak demand. Consumers are expected to react to such price signals by reducing usage, and thereby reduce peak demand. Reductions in peak demand will cause delays or cancellations in the need for new electric power plants.
- **Reduce system losses:** Smart Grid applications provide electric utilities with greater insight into the operation of their electric distribution systems. Such information can be used to configure the distribution system (e.g., the opening and closing of switches) in a manner that minimizes electric losses. Reductions in electric losses translate into a reduction in the total cost of electric supply and retail costs to consumers.

Future Renewable Energy Requirements

Section 5 contains a discussion of the regulatory and technological frameworks for promoting and facilitating energy resiliency in Oregon through the use of future renewable resources and Smart Grid applications. Examples of specific ways that renewable resources may be beneficial to Oregon's energy resiliency include:

- **Improve fuel diversity:** Oregon is heavily dependent on hydroelectric resources to meet its electric requirements. Increasing resource diversity improves the state's energy resiliency and ability to respond to large-scale events that affect electric supply. Renewable resources promote Oregon's energy resiliency, as they are likely to be independent of emergencies that affect availability of hydroelectric energy. The role that Smart Grid plays in such cases is to provide electric utilities with greater insight into the real-time operations and control of renewable resources.
- **Reduce response times to emergencies:** Damage to the electric grid could require significant repair and loss of service to Oregon's constituents. It is reasonable to

assume that repairs to larger facilities, such as high-voltage equipment or hydroelectric dams, would be more intrusive than that of smaller facilities. Since renewable resources are generally smaller in scale, it can then be argued that they might become operational faster than their large-scale counterparts.

- **Enhance reliability and dispatch:** Oregon's largest electric utilities do not include renewable resources in their emergency operating plans. Two key reasons are that renewable resources are considered to be less reliable than conventional resources and they cannot be dispatched. These obstacles can be partly addressed through the two-way communications capabilities that are common in Smart Grid applications.

Capturing these benefits requires a technological roadmap, which is discussed in Section 5 and includes:

- Identify key public facilities where electric service reliability is critical
- Require utilities to revise their outage restoration plans to include important public facilities
- Establish a minimum functionality requirements for any AMI project proposed by the state's utilities
- Require utilities to describe how data from AMI and Smart Grid technologies will be archived and utilized to improve utility asset management, operations, maintenance, planning processes, and electric reliability
- Evaluate market conditions that might impede the development of bulk wholesale renewable power sources

Recommended Next Steps

Lastly, Section 6 offers numerous candidate next steps that Oregon should consider to enhance the resiliency of electric supply. The broad categories under consideration include:

- Identification and documentation of critical assets
- Promotion of Smart Grid applications
- Review of electric utility operations
- Characterize emergency stakeholders (locations, energy requirements, backup capabilities and gaps)

Section 1
CRITICAL FACILITIES

Introduction

The overarching objective of this Section is to provide an assessment of the facilities that are critical to the overall energy picture in the state of Oregon. This objective is accomplished through the following steps:

- Utilize ODOE's existing data and reports.
- Assess an inventory of critical facilities, including:
  - Renewable resources[3]
  - Conventional electric generating assets[4]
  - Electric transmission lines[5]
  - Natural gas pipelines[6]
  - Back-up generating facilities[7]
  - Railroads and highway transportation[8]
- Assemble a general inventory of critical service providers.
- Assess blackstart capabilities of available distributed resource technologies.
- Identify existing energy and capacity that may be available from distributed and renewable resources.

Certain items were not assessed in this Report due to the confidential nature of such data or the lack of availability, including: electric backup capabilities (e.g., diesel generators) of emergency service providers (e.g., police and fire stations, hospitals, public works), bio-fuel infrastructure (e.g., biodiesel and ethanol supply, and manufacturing), and the capability of distributed resources to stockpile fuels or use multiple fuels.

Impacts of Renewable Resources on EAP

From the perspective of Oregon's EAP, it is important to note that the critical resources that are addressed in this Section, especially renewable resources such as

[3] An electronic database is provided separately.
[4] Ibid.
[5] Ibid.
[6] Ibid.
[7] The electric backup capabilities of emergency service providers (e.g., police and fire stations, hospitals, public works) are confidential and may be obtained by contacting each county.
[8] Transportation of bio-fuels is based on railroad and highway assets, which are identified later in this Section. Bio-fuel infrastructure is not available and could not be included in this Report.

wind and solar, can have a significantly beneficial impact on grid resiliency. Renewable resources are numerous, geographically dispersed, and independent of imported fuels. These features enhance the state's ability to withstand energy deficiencies, especially events that may be associated with disturbances that are caused by weather or seismic activity.

In contrast, conventional resources are much more geographically centralized than renewable resources. This is evident by examining the number and capacity of hydroelectric facilities that are located along the Columbia River, as addressed later in this Section. It is also highly likely that, over time, renewable resources will become more numerous than their conventional counterparts. Such characteristics directly reduce their exposure to outages and, thereby, enhance Oregon's electric resiliency.

While renewable resources are beneficial to energy assurance planning, their value in terms of electric capacity and control is open to debate. As discussed elsewhere in this Report, most renewable resources fail to provide the electric grid with the ability to be dispatched, voltage support, frequency support or a sufficient capacity factor (the likelihood of being available when called upon to serve).

Section 4 contains a more in-depth discussion of the electric resiliency benefits and grid integration challenges that are associated with renewable resources.

Methodology

The following renewable sector overviews were accomplished by utilizing existing data and reports from the ODOE, PUC, WECC, BPA, PacifiCorp, PGE, Northwest Power and Conservation Council (NWPCC), ODOT, EIA and the National Association of State Energy Officials (NASEO). In numerous instances, access to data and reports was precluded by the confidential nature of such information. Consequently, this Report is based on publically available data and reports.

The EIA collects extensive data on the electricity sector related to assets and the industry operations and its databases were queried for consumption data on a statewide basis.

This study concentrated on the reliability and resiliency of electric generation and transmission. By intent, the study did not inventory the distribution level assets as such assets fall below the level of focus for the Oregon EAP.

Criteria

Before developing critical facility inventories, it is essential to understand the criteria that is used to guide the concept of which infrastructure is "critical." Critical infrastructures are broadly defined in 1996 Executive Order 13010 and the USA Patriot Act of 2001 as energy, telecommunications, financial services, water, transportation, and cyber services that are critical to maintaining the national defense, continuity of government, economic prosperity, and quality of life in the United States

(U.S.).[9] [10] For the more specific purposes of energy assurance planning, this Project also utilized a set of guidelines that are consistent with the concepts put forward by the NASEO, which defines critical infrastructures as the primary assets that are ordinarily required for energy preparedness.[11] Critical assets are the components of the energy infrastructure that are vital and that their incapacity or unavailability would have a debilitating impact on the reliable production, transport, transformation delivery, and/or consumption of electric energy.

For the purposes of this Project, we further developed and applied a set of four criteria to screen the inventory of energy infrastructure assets. These criteria are differentiated below but essentially relate to the associated consequence, regardless of the subset of factors that create such consequence. It is solely the consequence of failure or disruption (whether economic, social or environmental) that concludes that an asset is critical. The four criteria outlined below are not mutually exclusive. There is some overlap, and not all are necessarily pertinent to each asset evaluated.

High-Risk Assets – A determination of whether an asset can withstand a disruption or loss, and the ability to recover quickly from such an event. Relevant attributes may include:

- Market dominance or capacity
- Number of customers served or affected
- Sensitivity of customer segments
- Strategic location
- Seasonal vulnerability
- Degree of redundancy
- Historical evidence of disruption

High Impact Assets – A relative assessment of the impact of the loss of an asset in terms of the potential crippling consequences to the state of Oregon. An asset may be classified as being high impact even in the absence of historical evidence.

High Redundancy Assets – This assessment identifies the availability of alternative energy assets, supplies or procedures that could reduce or shorten the energy disruption or condition and ameliorate the consequences

High Frequency Events – Those assets or combinations of assets, where past events have occurred or are expected to occur very often.

[9] CRS Report for Congress, Critical Infrastructure and Key Assets: Definition and Identification, October 1, 2004.
[10] USA Patriot Act of 2001, Section 1016(e), (42 U.S.C. 5195c(e)).
[11] National Association of State Energy Officials, State Energy Assurance Guidelines, Version 3.1, December 2009.

General Classifications

Based on the guidelines laid out by the NASEO and other guiding documents, the general classifications that have been considered in this Project include the following:

- Renewable resources for the production of electricity
- Hydroelectric generating resources
- Other conventional electric generating resources
- Electric transmission
- Electric distribution
- Backup generating facilities
- Smart Grid
- Natural gas
- Liquefied natural gas
- Transportation assets that affect energy resiliency
- Railroads
- Roads and highways
- Blackstart generating units

Each of the above general categories of critical assets are explored in greater detail in the following Sections.

Electric Generating Facilities

Critical electric generating plants in Oregon include its hydroelectric, conventional, and renewable resources. Each resource is explored below with the intent of identifying the ones that are critical to the purpose of energy assurance planning.

There is a difference between critical resources that are geographically located in Oregon and those that can serve Oregon's constituents during an electric supply emergency. The generation and transmission systems in the Pacific Northwest are highly interconnected. This makes it possible and even commonplace, under normal conditions, for an electric generator to be located in one state, schedule its delivery (energy and capacity) to many states or to a different state, and yet, due to the physics of electricity, actual flows may be delivered to a different set of states. These features are unavoidable, inherent to some hydroelectric plants in Oregon, and could lead to conflicts between states during an EAP event. Most importantly, the outcome of such conditions could be that different states might be looking to the same generating plant to serve its own electric needs during an emergency, thereby accidently "double accounting" such plant's impact and value to each state's electric resiliency. Addressing this dilemma is best accomplished by coordinating the emergency assurance planning process on a regional basis.

Renewable Resources

Oregon has seen extensive renewable energy resource development throughout the state. Reasons for utility and private capital investment of renewable energy developments include strong state and federal incentives and tax credits, compliance with the state Renewable Portfolio Standard, voluntary consumer programs such as PacifiCorp's Blue Sky program, increasing environmental protections on energy developments, and insulation against future energy costs at traditional developments. The following discussions identify the renewable resource generating assets – wind, solar, geothermal, bioenergy, and wave – in Oregon.

Wind

Wind resource data for Oregon is based on information from the EIA, which are listed below in Table 1-1 (Wind Resource Summary).[12] These data indicate that there are 22 operational projects in Oregon, though some are actually sub-projects within the same overall project. EIA indicates that Oregon has approximately 1,920 MW of installed nameplate capacity and that there is an additional 1,738 MW of wind capacity that has been approved, but not yet constructed, 454 MW that is in construction, and 2,380 MW that is being permitted. Assuming that all of these wind projects are completed and become operational, then there would be approximately 6,492 MW of wind capacity in Oregon.

[12] U.S. Department of Energy, Energy Information Administration, www.eia.doe.gov/fuelelectric.html

Table 1-1
Wind Resource Summary[13]

Wind Energy Projects in the Oregon (January 24, 2011)				
Projects under Oregon Energy Facility Siting Council Jurisdiction:				
Project	County	Turbines	MW (capacity)	Status
Antelope Ridge Wind Farm	Union	164	300	under Council review
Helix Wind Power Facility	Umatilla	68	102	approved but not built
Stateline Wind Project (Stateline 1&2)	Umatilla	186	123	operating
Stateline Wind Project (Stateline 3)	Umatilla	43	99	operating
Shepherds Flat North	Gilliam	106	265	under construction
Shepherds Flat Central	Gilliam/Morrow	116	290	under construction
Shepherds Flat South	Gilliam/Morrow	116	290	under construction
Saddle Butte Wind Park	Gilliam/Morrow	171	565	under Council review
Baseline Wind Energy Facility	Gilliam	250	500	under Council review
Leaning Juniper II Wind Power Facility	Gilliam	117	201	under construction
Montague Wind Power Facility	Gilliam	269	404	approved but not built
Rock Creek Wind Power Facility	Gilliam	275	550	under Council review
Biglow Canyon Wind Farm	Sherman	217	450	operating
Klondike III Wind Project	Sherman	176	300	operating
Golden Hills Wind Farm	Sherman	267	400	approved but not built
Summit Ridge Wind Project	Wasco	87	200	under Council review
Subtotal (EFSC)		**2,628**	**5,039**	
Other Wind Power Projects in Oregon:				
Project	County	Turbines	MW (capacity)	Status
Echanis Wind Project	Harney	60	104	county-approved but not built
Elkhorn	Union	61	101	operating
Combine Hills Turbine Ranch	Umatilla	104	104	operating
Vansycle Ridge	Umatilla	38	25	operating
Echo Windfarm	Umatilla/Morrow	39	64	operating
Threemile Wind	Morrow	6	10	under construction
Willow Creek	Morrow/Gilliam	48	72	operating
Condon Wind Energy	Gilliam	83	50	operating
Horn Butte	Gilliam	52	78	county-approved but not built
Pebble Springs	Gilliam	47	99	operating
Leaning Juniper I	Gilliam	67	101	operating
Rattlesnake Road	Gilliam	49	103	operating
Wheatfield	Gilliam	46	97	operating
Klondike I and II	Sherman	66	99	operating
Hay Canyon	Sherman	48	101	operating
PaTu Wind Farm (Oregon Trail Wind Farm)	Sherman	6	9	operating
Star Point	Sherman	49	103	operating
Subtotal (Other Oregon)		**869**	**1,320**	
Total (all facilities)		**3,497**	**6,359**	
Currently Operating		**1,477**	**2,204**	

[13] Ibid.

Solar

The development of solar generating facilities in Oregon has greatly lagged that of wind power. The EIA database indicates there are 38 solar facilities currently in Oregon that are operational plus two additional projects that are proposed. Operational and proposed projects have a total installed, nameplate, capacity of approximately 2.75 MW and 4.0 MW, totaling 6.75 MW.

Electric generating units that satisfy the needs of energy assurance planning are generally highly dependable, provide voltage and frequency support to the grid, and are sufficiently large enough to serve either an emergency service provider or a significant number of electric customers. Solar resources generally do not meet these criteria as they are not dispatchable, the nameplate capacity of individual units is too small to serve some emergency service providers, and have a capacity factor of 15 percent, which effectively lowers their expected capacity by 85 percent. Utilities and Independent System Operators (ISOs) have noted such characteristics in their arguments against including solar resources in their emergency resource portfolios. Consequently, it is assumed that solar resources that have a nameplate capacity of less than 100 kilowatts (kW) should not be considered in the context of energy assurance planning and are omitted from this analysis. Table 1-2 (Solar Resources Over 100 kW) lists 10 operating and proposed solar resources in Oregon that have a nameplate capacity of greater than 100 kW. Collectively, these units could hypothetically provide a maximum capacity of 6,638 kW. However, since the capacity factor of solar resources is commonly 15 percent, then their effective capacity is 996 kW.

The value of renewable resources to energy assurance planning is enhanced by the presence of electric storage devices, such as batteries. Examples of such applications in Oregon include:

- Medford, Oregon – radio station powered by solar voltaic with battery backup[14]
- Ontario, Oregon – traffic signals powered by solar voltaic with battery backup[15]

While the number of solar installations that have battery backup is small, it is expected to grow over time.

Table 1-2
Solar Resources Over 100 kW

Project	Resource	County	Capacity (kW)	Status
Pendleton Water Treatment	Solar	Umatilla	100	Operating
PGE/ODOT I-205	Solar	N/A	104	Operating
Kettle Foods	Solar	Lane	114	Operating
Pepsi Cola of Klamath Falls	Solar	Klamath	172	Operating

14 http://www.oregonsolarworks.com/solar/PORTFOLIO/SOLARCOMMERCIALINSTALLATIONS/tabid/59/Default.aspx

15 http://www.solar-traffic-controls.com/ITN/ITN-OntarioOR.php

Project	Resource	County	Capacity (kW)	Status
City of Gresham	Solar	Multnomah	419	Operating
Pepsi-Cola Eugene	Solar	Lane	252	Operating
Industrial Finishes	Solar	Lane	450	Operating
Portland Habilitation Center	Solar	Multnomah	870	Operating
Subtotal Operating			2,481	
Arlington Solar Project	Solar	Gilliam	2,000	Proposed
Christmas Valley	Solar	Lake	180	Proposed
Medford Reg. Water Reclam.	Solar	Jackson	2,000	Proposed
enXco (Salem)	Solar	Marion	2,840	Proposed
Christmas Valley	Solar	Lake	12,000	Proposed
Subtotal Proposed			19,202	
Total Solar			21,501	

Geothermal

Oregon's existing presence in the geothermal energy market is very small, yet forecasted to grow significantly. The EIA database identifies a total of five geothermal facilities in Oregon. One facility is in operation, two are in construction, one is being permitted, and one is proposed.[16] The facility that is in operation has a capacity of 0.3 MW, far below the threshold for being considered critical. The total capacity of all five facilities is 200.5 MW. The most significant facility in the group is the one, which is currently under review (Newberry Geothermal) with a capacity of 143 MW. All other facilities are comparatively small. Table 1-3 (Geothermal Resource Summary), below, lists the relevant geothermal energy facilities.

Geothermal resources also benefit grid resiliency by serving heating requirements. For example, the City of Klamath Falls, Oregon installed a geothermal heating system to serve the heating needs of government buildings, a wastewater treatment plant, and businesses that are located in its downtown core. The result is an enhancement to the areas energy resiliency since it is independent of events that could affect the supply of electricity or natural gas for heating.

[16] Ibid.

Table 1-3
Geothermal Resource Summary

Project	Resource	County	Capacity (MW)	Status
OIT Campus - phase 2	Geothermal	Klamath	1.2	In Construction
Neal Hot Springs Unit 1	Geothermal	Malheur	26.0	In Construction
Subtotal In Construction			27.2	
OIT Campus - phase 1	Geothermal	Klamath	0.3	Operating
Newberry Geothermal	Geothermal	Deschutes	143.0	Permitting
Crump Geyser	Geothermal	Lake	30.0	Proposed
Total Geothermal			200.5	

Wave

Oregon's coastline has recently drawn the attention of wave energy developers. Only one facility is in the construction phase, a 150-kW pilot buoy at the Reedsport site that will not be connected to the grid. Developer Ocean Power Technologies (OPT) has filed a license application to construct a grid-connected array of 10 buoys at 1.5 MW, with the possibility of expanding to 50 MW over the license term. Two other proposals have received preliminary permits from the Federal Energy Regulatory Commission (FERC): OPT for its Coos Bay project (100 MW) and Douglas County for a jetty project (3 MW). Several Oregon coastal communities, especially Tillamook and Newport, are considering a variety of development options for their off- and near-shore wave resources. Wave facilities are listed in Table 1-4 (Wave Resource Summary), below.

Table 1-4
Wave Resource Summary[17]

Project	Resource	County	Capacity (MW)	Status
Reedsport OPT Wave Park 1	Wave	Douglas	2	In Construction
Tillamook Intergovernment	Wave	Tillamook	20-180	Planning
Coos Bay	Wave	Coos	100	Planning
Douglas Co. Wave Project	Wave	Douglas	1-3	Planning

Wood

The potential to develop and utilize biomass in Oregon is significant. ODOE has completed an investigation into various sources of biomass and their associated

[17] "Oregon Wave Energy Trust Utility Market Initiative, Oregon Wave Project Database," Oregon Wave Energy Trust, December 2009

electric capacity.[18] It estimates that these sources generate approximately 12.7 million bone dry tons (bdt) of woody biomass in Oregon on an annual basis. Material collection and transportation costs currently inhibit the use of this resource for the purpose of producing electric energy. Consequently, the available woody biomass resource may be approximately 9.8 million bone dry tons per year. About 67 percent of the available resource is used for purposes other than energy production, primarily being used in the pulp and paper industries. About 26 percent is currently being used for electric energy production, which amounts to approximately 2.5 million bone dry tons per year or 43 trillion British thermal units (Btu) per year. The remaining seven percent of available woody resources are not being used for energy production or other purposes. This untapped resource amounts to 0.7 million bone dry tons of woody biomass per year, which is potentially equivalent to approximately 12 trillion Btu (TBtu) per year.

Forest Biomass

Tree tops, limbs, and cull material left over from logging activity provided approximately 3.3 million bdt of forest biomass residue in 2004. An estimated 0.63 million bdt of forest biomass was economically available to be used for energy production, which has an energy value of 10.8 TBtu.

Urban Wood Waste

Wood is discarded from individual households, commercial businesses, and construction and demolition sites. ODOE estimates that 0.56 million bdt of urban wood waste was discarded in Oregon in 2004.

It is estimated that increasing the rate of recovery of urban wood waste could capture an additional 14,000 bdt of urban wood waste per year, resulting in an energy value of 0.24 TBtu.

Hybrid Poplar Plantations

In the future, a dedicated feedstock supply of short-rotation woody crops, such as hybrid poplar, could be a fuel source for the biomass power industry. The U.S. DOE estimates residue yield ranges from 7 to 15 bdt of fuel per acre per year and a gross energy value of 0.12 to 0.26 TBtu per year.

Pulping Liquor

The pulping process produces a waste stream of spent pulping liquor. Pulp mills burn the pulping liquor to recover and recycle the chemicals used in the pulping process. Two pulp mills in Oregon use boilers to cogenerate steam and electricity. ODOE estimates that the energy content of pulping liquor consumed in Oregon in 2004 was approximately 35 TBtu.

[18] Oregon Department of Energy at http://www.oregon.gov/ENERGY/RENEWBiomass/resource.shtml

Municipal Solid Waste

Approximately 70 percent of the waste disposed of in landfills is biomass material, which includes: food waste, waste paper, cardboard, and wood waste. Municipal solid waste has an energy content of about 4,500 Btu per pound. Its potential energy value in 2004 was approximately 18 TBtu.

Wastewater Treatment

Anaerobic digesters reduce the organic content of wastewater and decrease the amount of sludge disposal required at wastewater treatment facilities. The biogas generated in the process is often used as boiler fuel to supply heat for the digesters and other treatment facility applications. Nine wastewater treatment facilities in Oregon use the gas to produce electricity. ODOE estimates that, in 2004, the unused gas had an energy value of approximately 0.3 TBtu.

Organic Waste Digesters

Manure from livestock on Oregon farms is a resource for the production of biogas through anaerobic digestion technology. Other organic wastes, such as agricultural and food-processing wastes, could also be used as digester feedstock. ODOE estimates that approximately 1.7 TBtu could be utilized.

Landfill Gas

Anaerobic digestion of organic materials in landfills produces landfill gas. The U.S. Environmental Protection Agency (EPA) estimates that approximately 4,600 million cubic feet (mcf) of landfill gas is potentially available on an annual basis in Oregon. The energy value of this quantity of landfill gas is approximately 2.3 TBtu.

Agricultural Residue

The harvest of field crops and grass seed generates a residue of straw, stalks, and stubble. In 2003, approximately 1.5 million dry tons of agricultural residue was available from farming activities in Oregon. The energy content of this resource was about 27 TBtu.

Table 1-5
Summary of Biomass Energy Resources

Resources	Quantity Available (2004)	Energy Value (TBtu)	Potential Electric Generation (average megawatts)
Wood	0.7 million bdt	12.0	96
Pulping Liquor	2.0 million bdt	25.0	57
Municipal Solid Waste	1.3 million bdt	18.0	121
Wastewater Treatment	460 mcf	0.3	2
Organic Waste Digesters	3,400 mcf	1.7	13
Landfill Gas	4,600 mcf	2.3	22
Agricultural Residue	1.5 million bdt	27.0	213
Total		86.3	524

Source: Oregon Department of Energy, http://www.oregon.gov/ENERGY/RENEW/Biomass/resource.shtml#Summary

Table 1-6
Biomass Summary[19]

Project	Primary Fuel	Capacity (kW)
Alan David LLC	Biomass	
Cal-Gon Farms	Manure	100
Port of Tillamook Bay MEAD project	Manure	400
Subtotal		500
EWEB fuel cells (two 5-kW units)	Methanol	10
PGE Earth Advantage fuel cell	Methanol	5
Subtotal		15
Covanta Marion	Municipal Solid Waste	13,100
Georgia-Pacific – Wauna	Spent Pulping Liquor	36,000
Weyerhaeuser – Springfield 1	Spent Pulping Liquor	
Weyerhaeuser – Springfield 2	Spent Pulping Liquor	
Weyerhaeuser – Springfield 3	Spent Pulping Liquor	12,500
Weyerhaeuser – Springfield 4	Spent Pulping Liquor	40,000
Weyerhaeuser – Albany	Spent Pulping Liquor	45,000
Subtotal		133,500
Columbia Boulevard fuel cell	Wastewater Gas	200
Columbia Boulevard microturbines	Wastewater Gas	120
Corvallis Wastewater Plant	Wastewater Gas	55
Durham Wastewater Plant	Wastewater Gas	250
Eugene/Springfield Wastewater Plant	Wastewater Gas	800
Gresham Wastewater Plant	Wastewater Gas	200
Kellogg Creek Wastewater Plant	Wastewater Gas	250
Medford Wastewater Plant	Wastewater Gas	700

19 Ibid.

Project	Primary Fuel	Capacity (kW)
Rock Creek Wastewater Plant	Wastewater Gas	1,000
Tri-City Service District	Wastewater Gas	250
Willow Lake Wastewater Plant	Wastewater Gas	800
Subtotal		4,625
Biomass One	Wood Residue	30,000
Blue Mountain Forest Products	Wood Residue	
Boise Cascade – Medford	Wood Residue	6,800
Co-Gen II	Wood Residue	7,500
Crown Pacific	Wood Residue	1,500
Heppner Power Plant	Wood Residue	
Lebanite	Wood Residue	
Prairie Wood Products (Co-Gen I)	Wood Residue	7,500
Roseburg Forest Products – Dillard	Wood Residue	45,000
Warm Springs Forest Products	Wood Residue	3,000
Subtotal		101,300
Total		253,040

Biofuel Production in Oregon

Biofuels could be an important substitutable fuel for Oregon's emergency service providers during energy disruptions. Petroleum requirements of police and fire vehicles can be served, in part, by ethanol. Coal-fired electric generating stations might be able to supplement hypothetical shortages in coals with biomass (e.g., woody biomass, pellets, landfill gas). A survey of certain organizations finds that state-wide production of biofuels during the year 2010 was approximately 40.7 million gallons. However, the total annual production capacity of these sources is significantly greater and is reported to be approximately 162 million gallons. The difference between historical and potential biofuel production is largely due to several facilities being non-operable as a consequence of economic conditions. These results are summarized in the following table.

Table 1-7
Biofuel Summary

Organization	Product	Production Yr 2010 (Gallons)	Potential Production Capacity (Gallons/Yr)	Storage Capacity (Gallons)	Input Fuel Source	Primary Input Fuel Transport	Primary Product Transport
Columbia Pacific Biorefinery	Denatured Alcohol	-	120,000,000	8,300,000	Midwestern Grain	Rail	Barge/Truck
GreenFuels of Oregon	Biodiesel (B99)	-	1,000,000	25,000	Oregon	Rail	Truck
Lookout Mountain Biodiesel	Biodiesel (B100)	-	10,000	7,000	Oregon Cooking Oil	Truck	Truck
Pacific Ethanol	Ethanol (E10, E85)	40,000,000	40,000,000	1,000,000	Midwestern Corn	Rail	Barge/Truck
Rogue Biofuels	Waste Oil Transport	-	-	3,000	Oregon	Truck	Truck
Beaver Biodiesel	Biodiesel	760,000	960,000	60,000	Regional	Truck	Truck
SeQuential Pacific	Biodiesel (B100)	4,000,000	20,000,000	500,000	Oregon	Truck	Truck
Total		44,760,000	181,970,000	9,895,000			

Hydroelectric Resources

The Pacific Northwest and especially Oregon, utilize a significant amount of hydroelectric resources. Figure 1-1 (Hydroelectric Facilities in the Pacific Northwest) depicts existing federal (BPA), non-federal, and Canadian dams. Specific locations are numerous and widespread, yet focus on a relatively small number of rivers. Table 1-8 (Federal Hydroelectric Facilities) lists key data for each facility that is operated by the U.S. Army Corps of Engineers.

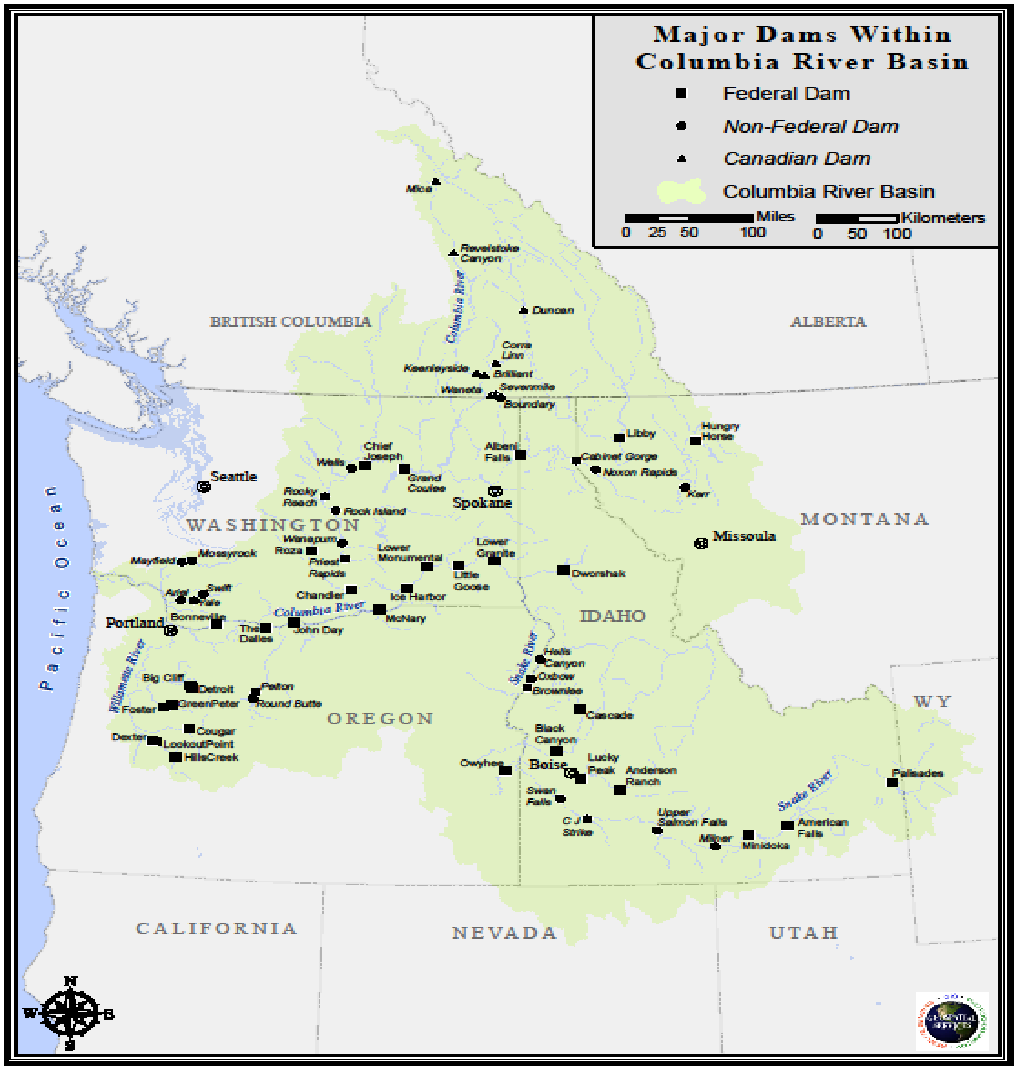

Figure 1-1: Hydroelectric Facilities in the Pacific Northwest[20]

[20] Bonneville Power Administration, http://transmission.bpa.gov/LanCom/Geographic_Information_Services/pdf/CRB_Dams.pdf

Table 1-8
Federal Hydroelectric Facilities[21]

Name	River, State	In Service	Nameplate Rating
Albeni Falls	Pend Oreille, ID	1955	43 MW
Anderson Ranch	Boise, ID	1950	40 MW
Big Cliff	Santiam, OR	1953	18 MW
Black Canyon	Payette, ID	1925	10 MW
Boise River Diversion	Boise, ID	1912	3 MW
Bonneville	Columbia, OR/WA	1938	1,077 MW
Chandler	Yakima, WA	1956	12 MW
Chief Joseph	Columbia, WA	1958	2,458 MW
Cougar	McKenzie, OR	1963	25 MW
Detroit	Santiam, OR	1953	100 MW
Dexter	Willamette, OR	1954	15 MW
Dworshak	Clearwater, ID	1973	400 MW
Foster	Santiam, OR	1967	20 MW
Grand Coulee [10/]	Columbia, WA	1942	6,765 MW
Green Peter	Santiam, OR	1967	80 MW
Green Springs	Emigrant Crk, OR	1960	16 MW
Hills Creek	Willamette, OR	1962	30 MW
Hungry Horse	Flathead, MT	1953	428 MW
Ice harbor	Snake, WA	1962	603 MW
John Day	Columbia, OR/WA	1971	2,160 MW
Libby	Kootenai, MT	1975	525 MW
Little Goose	Snake, WA	1970	810 MW
Lookout Point	Willamette, OR	1953	120 MW
Lost Creek	Rogue, OR	1977	49 MW
Lower Granit	Snake, WA	1975	810 MW
Lower Monumental	Snake, WA	1969	810 MW
McNary	Columbia, OR/WA	1952	980 MW
Minidoka	Snake, ID	1909	28 MW
Palisades	Snake, ID	1958	176 MW
Roza	Yakima, WA	1958	11 MW
The Dalles	Columbia, OR/WA	1957	1,808 MW
Total (31 dams)			20,430 MW

Source: BPA 2010

The total installed capacity of BPA's four largest hydroelectric facilities located in Oregon is approximately 6,205 MW (Bonneville, John Day, McNary, and The Dalles). Each of these facilities are considered to be critical for the purposes of EAP.

[21] Ibid.

Additional non-federal hydroelectric facilities also play a significant role in serving Oregon's constituents. Table 1-9 (Hydroelectric Facilities) provides a more complete picture of hydroelectric facilities. These data indicate that the total hydroelectric capacity that is located in Oregon (including facilities located on the Columbia River) is approximately 7,600 MW. Federal facilities account for nearly 80 percent of the total hydroelectric generation in Oregon.

Table 1-9
Hydroelectric Facilities[22] [23]

Facility	Capacity (MW)
Bend Power 1 - 3	1.11
Big Cliff	18.00
Brunswick Creek	0.04
Bull Run No. 1	23.70
Bull Run No. 2	11.80
Canal Creek	1.10
Canyon Creek	0.08
Carmen-Smith 1-3	114.30
City of Albany/Vine Street WTP	0.50
Clearwater 1	15.00
Clearwater 2	26.00
Copper Dam	3.00
Cougar 1 & 2	26.00
Denny Creek	0.08
Detroit 1 & 2	100.00
Dexter	15.00
Eagle Point	2.80
East Side	3.20
Falls Creek	4.10
Faraday 1 - 6	36.60
Ferguson Ridge	1.90
Fish Creek	11.00
Foster 1 & 2	20.00
Galesville	1.60
Gold Ray 1 - 2	1.50
Goodrich	0.08
Green Peter 1 & 2	80.00
Green Springs	17.20
Hills Creek 1 & 2	30.00

[22] U.S. Department of Energy, Energy Information Administration.
[23] "Electricity Generation for the Pacific Northwest," Northwest Power and Conservation Council, June 2006.

Facility	Capacity (MW)
Jim Boyd	1.20
John C. Boyle 1 & 2	98.70
Lacomb	0.96
Lake Creek No 1	0.05
Lake Oswego	0.54
Leaburg 1 & 2	13.50
Lemolo 1	32.16
Lemolo 2	33.00
Lookout Point 1 - 3	120.00
Lost Creek 1 - 2	49.00
Marion Investment	0.90
McKenzie	4.00
Middle Fork Irrigation District 1	0.60
Middle Fork Irrigation District 2	0.60
Middle Fork Irrigation District 3	2.10
Mill Creek (Cove) 1 & 2	1.00
Minikahda	0.07
Mitchell Butte	1.88
Mt. Tabor	0.17
Nichols Gap	0.90
North Fork 1 & 2	40.80
North Fork Sprague River	1.23
Oak Grove (Three Lynx) 1 & 2	51.00
Odell Creek	0.23
Opal Springs	4.30
Oregon City	1.50
Owyhee Dam	4.34
Owyhee Tunnel No. 1	7.00
Pelton 1- 3	109.80
Pelton Reregulation Dam	18.90
Peters Drive	1.80
Prospect 1	3.75
Prospect 2 (1 & 2)	32.00
Prospect 3	7.20
Prospect 4	1.00
Reeder Gulch	0.76
River Mill 1 - 5	19.10
Rock Creek 1 & 2	0.80
Round Butte 2	82.30
Round Butte 3	82.30

Facility	Capacity (MW)
Siphon	5.40
Slide Creek	18.00
Soda Springs Dam	11.00
Stayton	0.60
Stone Creek	12.00
T.W. Sullivan 1 - 13	15.40
Thompson's Mills	0.10
Toketee Falls 1-3	42.60
Trail Bridge	10.00
Upper Little Sheep Creek	4.30
Wallowa Falls	1.10
Walterville	8.00
Water Street	0.16
West Linn	3.60
West Side	0.60
Willamette Falls/Sullivan	14.40
Wolf Creek	0.12
Subtotal OR Hydro	1,544.51
Bonneville Dam	1,077.00
John Day Dam	2,160.00
McNary Dam	980.00
The Dalles Dam	1,808.00
Subtotal OR Hydro	6,025.00
Total	7,569.51

Conventional Electric Generation Resources

Oregon's primary electric resource is hydroelectric power, accounting for approximately 64 percent of total capacity that is located within the state. Other conventional resources account for the remaining 36 percent with natural gas (29 percent) and coal (five percent) ranking second and third. There is also a very small amount of petroleum and pumped hydroelectric resources, but these amount to only one percent of the total portfolio. The mix of resources that are located in Oregon is shown below in Table 1-10 (Electric Generating Units Located in Oregon) and Figure 1-2 (Electric Generation Portfolio).

Table 1-10
Electric Generating Units Located in Oregon[24] [25]

Resource	Capacity (MW)	Percent
Coal	615	5%
Hydro`	7,609	64%
Natural Gas	3,464	29%
Petroleum	128	1%
Pumped Storage	5	0%
Total	11,821	100%

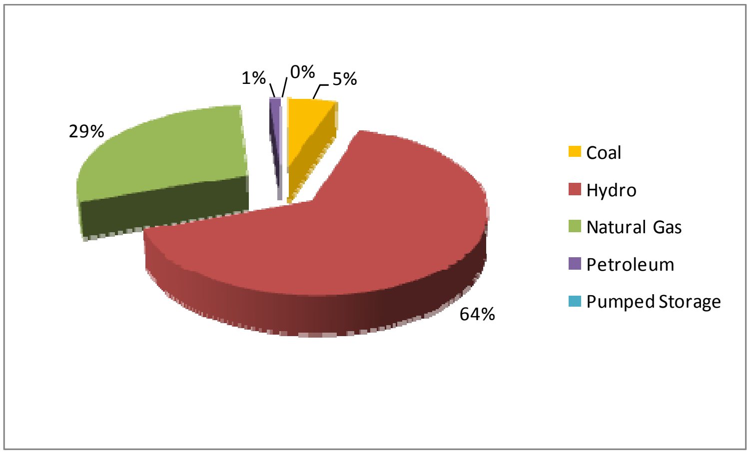

Figure 1-2: Electric Generating Plants Located in Oregon

The above data pertains to electric generating plants that are geographically located in Oregon. However, the location of an electric generating plant is not the same as its delivery of electricity. In terms of electric usage, Oregon's portfolio of electric resources is shown below in Figure 1-3 (Electricity Usage in Oregon by Resource). Usage data for the 2006-2008 time-frame finds that approximately 44 percent of the electricity consumed in Oregon was generated by hydroelectric resources.[26] The second most prevalent resource was coal (from out of state plants), totaling 37 percent.

[24] U.S. Department of Energy, Energy Information Administration.
[25] "Electricity Generation for the Pacific Northwest," Northwest Power and Conservation Council, June 2006.
[26] "Oregon State Energy Assurance Plan," ODOE, March 2011.

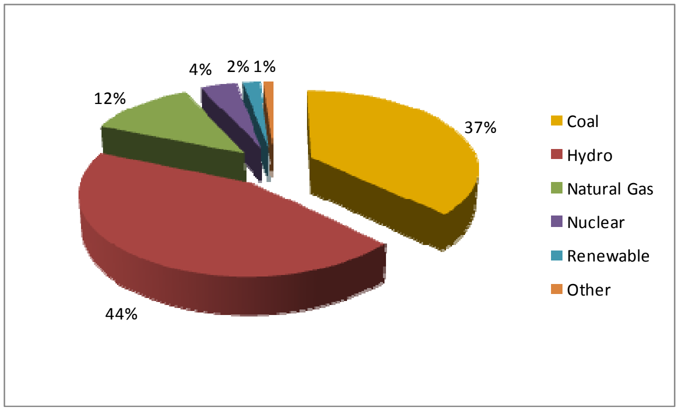

Figure 1-3: Electricity Usage in Oregon by Resource

Specific critical assets are identified by examining a more detailed list of conventional generating units. Table 1-11 (Conventional Resource Summary – without Hydroelectric) shows that approximately 66 percent of Oregon's non-hydroelectric conventional resources are consolidated in its five largest plants. One of these plants is coal fueled (Boardman) and the remaining four are natural gas fired (Hermiston, Beaver, Klamath, and Port Westward).

After applying the criteria for determining whether a facility is critical, Oregon's largest five conventional power plants should be included in the list of critical assets.

It should be noted that this evaluation is independent of conducting any detailed engineering analysis (e.g., power flow or transient stability studies) to assess the impacts that other plants might have on regional or local voltage or frequency control. Such follow-up studies are important but outside of the scope of this Report.

Table 1-11
Conventional Resource Summary – without Hydroelectric[27]

Facility	Fuel Type	Name Plate Capacity (MW)	Percent	Cummulative Percent
Hermiston Power Project	Natural gas	689.40	16%	16%
Boardman	Coal	601.00	14%	31%
Beaver 1 - 7	Natural gas	586.20	14%	45%
Klamath Cogeneration Project	Natural gas	501.50	12%	56%
Port Westward	Natural gas	399.00	9%	66%
Coyote Springs 2	Natural gas	287.00	7%	73%
Coyote Springs 1	Natural gas	266.40	6%	79%
Hermiston Generating Project	Natural gas	234.50	6%	85%
SP Newsprint	Natural gas	163.30	4%	89%
Bethel 1	Petroleum	56.70	1%	90%
Bethel 2	Petroleum	56.70	1%	91%
International Papaer (Albany) 01	Natural gas	51.00	1%	92%
Klamath Generation Peakers 1 & 2	Natural gas	50.00	1%	94%
Klamath Generation Peakers 3 & 4	Natural gas	50.00	1%	95%
Wauna Cogeneration	Natural Gas	36.00	1%	96%
Morrow Power	Natural gas	25.00	1%	96%
Willamette Steam 2 & 3	Natural gas	25.00	1%	97%
Beaver 8	Natural gas	24.50	1%	97%
Blue Heron Paper	Natural gas	15.00	0%	98%
Amalgamated Sugar/TASCO/Nyassa	Coal	14.00	0%	98%
Wah Chang	Natural gas	14.00	0%	98%
Alden Bailey (Wauna Peaking/Loki)	Natural gas	10.90	0%	99%
18th Street Springfield	Natural gas	9.50	0%	99%
D.R. Johnson. Cogen 1 & 2	Natural gas	7.50	0%	99%
U.S. Bankcorp	Petroleum	6.40	0%	99%
SierraPine Medite	Natural gas	6.00	0%	99%
Oregon State Energy Center	Natural gas	5.50	0%	100%
Ground Water Pumping Station	Pump Storage	5.40	0%	100%
Summit 1	Petroleum	3.00	0%	100%
Summit 2	Petroleum	3.00	0%	100%
University of Oregon 003	Natural gas	2.50	0%	100%
Burrill Lumber	Natural gas	1.50	0%	100%
University of Oregon 001	Natural gas	1.50	0%	100%
University of Oregon 002	Natural gas	1.50	0%	100%
Fortix	Petroleum	1.20	0%	100%
MacClaren	Petroleum	0.50	0%	100%
Total		4,212.10	100%	

[27] Ibid.

Electric Transmission

Organizational Responsibilities

The prudent management, operations, planning and maintenance of bulk power transmission and generation grids play a fundamental role in Oregon's electric resiliency. The grid that serves the state of Oregon is well organized, coordinated, and highly interconnected with similar systems in the 13 western U.S. states, parts of northern Mexico and western Canada. Critical grid functions, in relation to Oregon, are most predominately the responsibility of the BPA, WECC, PacifiCorp and PGE. On a local level, the electric distribution systems (and some transmission and generation) are also the responsibility of Oregon's numerous municipal and public power agencies. Being integrated, Oregon's generation and transmission systems are exposed to adverse events that may be caused over a thousand miles away. In theory, Oregon's electric resiliency (e.g., reliability) can be significantly impacted by transmission or generation related events that could occur anywhere in the entire interconnected region. Conversely, events emanating within Oregon could also significantly impact other states.

Elsewhere in the United States, regional transmission organizations (RTO) and ISOs have been formed to be responsible for the transmission of electricity over large interstate areas. An RTO coordinates, controls and monitors the electricity of a transmission grid that is much larger than a typical electric utility's system. ISOs are organizations that are formed at the direction or recommendation of the FERC. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system, usually within a single state, but sometimes encompassing multiple states. RTOs typically perform the same functions as ISOs, but cover a larger geographic area. Formally, there are no RTOs or ISOs in state of Oregon. However, the functions that are commonly performed by an RTO or ISO have been generally adopted by the BPA.

The resiliency of Oregon's electric grid may also be affected by the Northern Tier Transmission Group (NTTG), an effort that will strive to focus on regional transmission grid management in the states of Idaho, Montana, Oregon, Utah, and Wyoming. NTTG's membership includes Deseret, IPC, PacifiCorp, PGE, NorthWestern Energy and Utah Associated Municipal Power Systems (UAMPS). The NTTG is not a FERC-approved ISO or RTO. On June 13, 2007, the NTTG presented the FERC with their "straw" mission statement which states, "To ensure efficient, effective, coordinated use & expansion of the member's transmission systems in the Western Interconnection to best meet the needs of customers & stakeholders." One additional organization, ColumbiaGrid, is also of importance to Oregon's bulk power grid, though its primary focus is on the state of Washington. ColumbiaGrid is a non-profit corporation. While not an RTO, it seeks to achieve certain benefits and objectives of an RTO. Its members include Avista, BPA, Chelan County Public Utility District (PUD), Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. ColumbiaGrid performs single-utility transmission planning through an open and transparent process and a multi-system Open Access Same-Time Information System (OASIS) portal.

Critical Transmission Lines

Over 15,000 miles of lines in or near Oregon are classified as being transmission lines. Certain transmission lines are critical to Oregon's energy resiliency as they are directly responsible for the transport of electricity from large generating plants to customer loads, inter-utility electricity transfers (facilitation of electricity markets) and regional reliability. In this context, regional reliability is addressed by North American Electric Reliability Corporation (NERC) Standards, which requires electric utilities, ISOs, and transmission owners to plan, design, and construct the grid in a manner that can generally withstand certain unplanned events, such as the loss of a single grid element. BPA, PacifiCorp, WECC, and numerous in-state municipal utilities and electric cooperatives are responsible for compliance with NERC Standards and routinely conduct numerous studies to achieve such compliance. However, Oregon's transmission grid is not capable of withstanding the large-scale events that are contemplated within energy assurance planning,

The conditions that encompass energy assurance planning include transmission-related events that are generally much more catastrophic in nature than those described by the NERC Standards and may cause the unplanned outage of numerous grid elements. The transmission studies conducted by BPA, WECC, and Oregon's utilities do not simulate the effects of large-scale events. Moreover, it is impossible to accurately predict which transmission lines might be affected. Consequently, the most practical approach is to identify Oregon's critical transmission lines and track their operational status during any hypothetical events.

In the context of energy assurance planning, it would be desirable to define the criticality of a transmission line by the following:[28]

- Severe Impacts: The loss of such transmission lines result in significant impacts such as the curtailment of electric service to a large number of customers.
- Exposure or Frequency of Loss: The transmission line is highly exposed to outages or has demonstrated a high frequency of outages.
- Mitigation: There are no prudent mitigation plans to address the loss of such transmission lines, which may result in severe impacts.
- Combinations of the Above: The above criteria are not mutually exclusive and moderate levels of severity, exposure, frequency or mitigation can be used to determine criticality.

However, access to sufficient data regarding each of these criteria is either not available or considered to be confidential. Consequently, an alternative approach is used here, which bases criticality on the expected usage or intent of transmission lines. Industry best practices indicate that transmission lines rated at or above 345 kV are generally used to facilitate regional electric supply, interconnect large electric generating resources. These lines are considered to be critical due to the potential impacts that would be experienced by Oregon's economy and large numbers of customers.

[28] U.S. DOE

In addition, many of the 230-kV and 287-kV transmission lines are likely critical infrastructure for Oregon, yet a detailed determination requires a case-by-case evaluation. BPA was contacted to jointly review the performance and operation of its specific transmission lines. However, for reasons of security, BPA was unable to share pertinent information

Identifying Oregon's critical transmission lines is based on Ventyx's Energy Velocity database.[29] An electronic copy of the relevant portions of the entire database are provided separately. Figure 1-4 (Oregon's Critical Transmission Lines) and Table 1-12 (Oregon's Transmission Lines Equal to and Greater than 345 kV), below, summarize the Oregon's critical transmission assets.

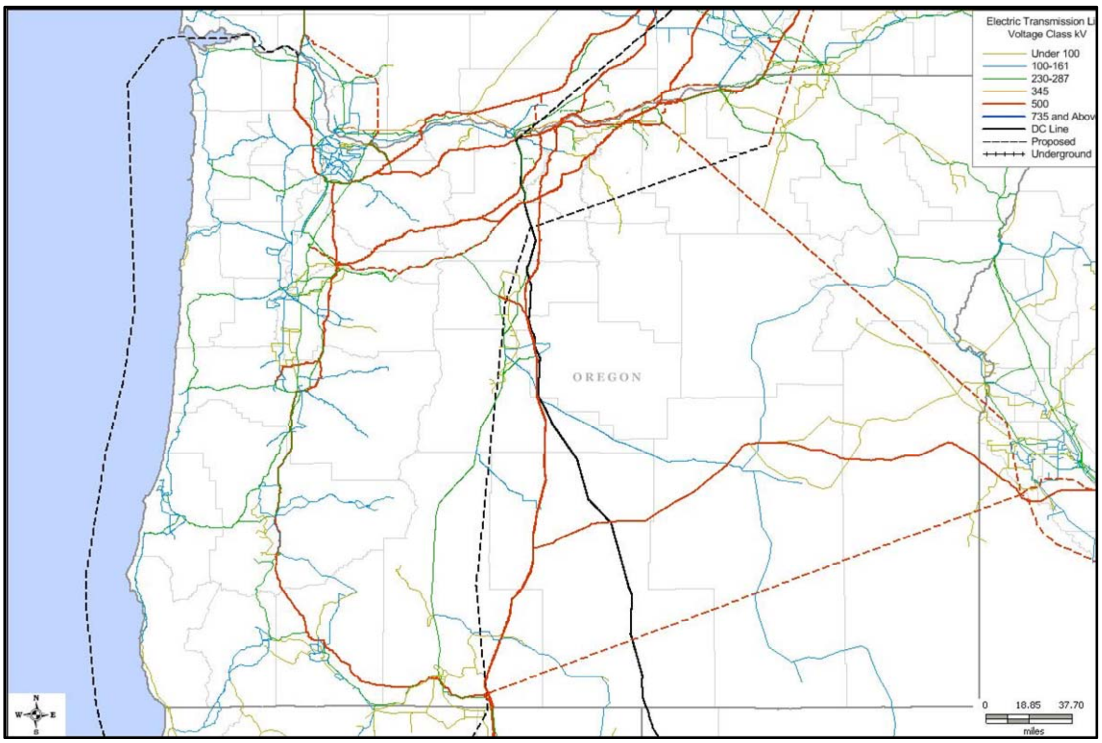

Figure 1-4: Oregon's Critical Transmission Lines[30]

[29] http://www.ventyx.com/

[30] Ibid.

Table 1-12
Oregon Transmission Lines at or Above 345 kV[31]

Utility	Voltage (kV)	From Substation	State	To Substation	State
Bonneville Power Administration	500	Paul	ID	Allston	OR
Bonneville Power Administration	500	Paul	ID	Allston	OR
Portland General Electric Co	500	Boardman (OR)	OR	Slatt	OR
Portland General Electric Co	500	Round Butte	OR	Grizzly	CA
Portland General Electric Co	500	Tap	CA	Coyote Springs	OR
Bonneville Power Administration	500	Lower Monumental	WA	McNary	OR
PacifiCorp	500	Alvey	OR	Dixonville 500	OR
PacifiCorp	500	Dixonville 500	OR	Meridian	OR
Western Area Power Administration	500	Tap	CA	Olinda (Vic Fazio)	CA
Pacific Gas & Electric Co	500	Malin	OR	Round Mountain	CA
PacifiCorp	500	Captain Jack	OR	Malin	OR
PacifiCorp	500	Burns	CA	Summer Lake	OR
PacifiCorp	500	Malin	OR	Grizzly	CA
PacifiCorp	500	Tap	CA	Ponderosa	OR
PacifiCorp	500	Malin	OR	Summer Lake	OR
PacifiCorp	500	Burns	CA	Midpoint	ID
Bonneville Power Administration	500	Big Eddy 500KV	OR	Big Eddy	OR
Bonneville Power Administration	500	Ostrander	OR	McLoughlin	OR
Bonneville Power Administration	500	Ostrander	OR	Troutdale	OR
Bonneville Power Administration	500	Marion	CA	Santium	OR
Bonneville Power Administration	500	Ostrander	OR	Big Eddy 500KV	OR
Bonneville Power Administration	500	Keeler	OR	Allston	OR
Bonneville Power Administration	500	Marion	CA	Lane	OR
Bonneville Power Administration	500	Marion	CA	Alvey	OR
Bonneville Power Administration	500	Pearl	NV	Marion	CA
Bonneville Power Administration	500	Pearl	NV	Keeler	OR
Bonneville Power Administration	500	Ostrander	OR	Pearl	NV
Bonneville Power Administration	500	John Day	OR	Marion	CA
Bonneville Power Administration	500	Buckley	OR	Marion	CA
Bonneville Power Administration	500	Captain Jack	OR	Malin	OR
Bonneville Power Administration	800	Celilo DC Converter Station	OR	Tap	CA
Bonneville Power Administration	500	Grizzly	CA	Summer Lake	OR
Bonneville Power Administration	500	Grizzly	CA	Captain Jack	OR
PacifiCorp	500	Malin	OR	Round Mountain	CA
Bonneville Power Administration	500	Captain Jack	OR	Tap	CA
Bonneville Power Administration	500	Ashe	WA	Marion	CA
Bonneville Power Administration	500	Hanford	WA	Ostrander	OR
Bonneville Power Administration	500	Big Eddy 500KV	OR	John Day	OR
Bonneville Power Administration	345	McNary	OR	Ross	WA
Bonneville Power Administration	500	McNary	OR	Slatt	OR
Bonneville Power Administration	500	John Day	OR	Big Eddy 500KV	OR
Bonneville Power Administration	500	Slatt	OR	Buckley	OR

[31] Ibid.

Utility	Voltage (kV)	From Substation	State	To Substation	State
Bonneville Power Administration	500	John Day	OR	John Day	OR
Bonneville Power Administration	500	Slatt	OR	John Day	OR
Bonneville Power Administration	500	John Day	OR	Grizzly	CA
Bonneville Power Administration	500	John Day	OR	Grizzly	CA
Bonneville Power Administration	500	Hanford	WA	John Day	OR
Bonneville Power Administration	500	Ashe	WA	Slatt	OR
Bonneville Power Administration	500	Big Eddy 500KV	OR	Celilo DC Converter Station	OR
Bonneville Power Administration	500	Tap	CA	Sacajawea	WA
Bonneville Power Administration	500	Buckley	OR	Grizzly	CA
PacifiCorp	500	Meridian	OR	Captain Jack	OR
Los Angeles Dept of Water & Power	800	Tap	CA	Sylmar East	CA

In addition to the above analysis, a prior BPA study notes that the transmission system in the Pacific Northwest is becoming increasingly congested. In 2005, the regional grid exceeded its limits for reliable operating conditions for more than five minutes on 29 occasions and that 16 of these events required emergency action to curtail power transfers or to change the dispatch of generation.[32] The regional transmission system contains numerous “flowgates” or bottlenecks that constrain the interstate transfer of electricity between Washington, Oregon, and Idaho, as well as intrastate transfers. A flowgate is defined as a group of high-voltage transmission lines that represent a collective weak-link in the grid and the ability to transfer electricity between states, regions or within a state. Such flowgates indicate specific weak points in the transmission system and should receive additional scrutiny in an EAP. An unplanned outage of any individual transmission line that is a part of a flowgate generally results in a reduction in the grid’s ability to transfer electrical power.

Flowgates that directly affect Oregon include:[33]

- Three separate flowgates that affect north-south transfers between Oregon and California
- Three separate flowgates that affect north-south transfers between Oregon and Washington
- Four separate flowgates that affect east-west transfers within Oregon

BPA reports that it annually studies and recommends solutions to all pertinent flowgates to identify potential adverse impacts on grid reliability.

A second U.S. DOE study also expressed a similar concern about the Pacific Northwest and specifically identified Portland as an area of significant congestion.[34]

[32] “Challenge for the Northwest, Protecting and Managing an Increasingly Congested Transmission System,” Bonneville Power Administration, April 2006.
[33] Ibid.
[34] “National Electric Transmission Congestion Study,” U. S. Department of Energy, December 2009.

In addition to transmission assets, BPA is also responsible for 260 substations. High voltage substations are commonly considered to be critical, but detailed information about these facilities is not available to the public.

Future Transmission Lines

Three future transmission projects are currently in the regulatory process that, if completed, should be included in Oregon's list of critical transmission lines.

- Big Eddy - Knight 500 kV
- Boardman - Hemingway 500 kV
- Boardman – Salem 500 kV

Critical Transmission Assets and Infrastructure – NTTG and ColumbiaGrid

In addition to BPA's critical transmission assets, information regarding the transmission systems of the members of the NTTG and ColumbiaGrid were also investigated. BPA is also a member of ColumbiaGrid and double accounting must be avoided.

Figure 1-5 (NTTG and ColumbiaGrid Transmission Systems), below depicts the transmission systems that are associated with NTTG (shown in red lines) and ColumbiaGrid (shown in black lines).

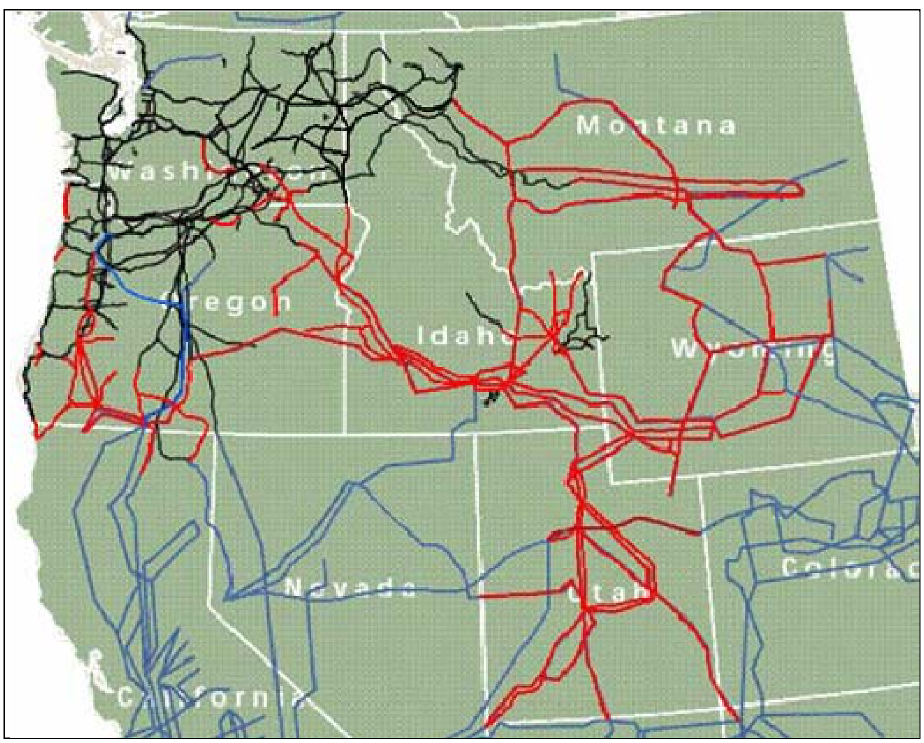

Figure 1-5: NTTG and ColumbiaGrid Transmission Systems[35]

[35] "Planning Straw Proposal," FERC Technical Conference, Northern Tier Transmission Group, Park City, Utah, June 13, 2007.

Electric Distribution

The purpose of the electric distribution system is to safely and reliably carry electricity from substations to the customer. In general, electric distribution systems are not considered to be critical since they serve a relatively small number of customers, can be repaired relatively quickly, contain assets that are comparatively lower in cost, and retail electricity service providers may have the ability to serve customers from backup feeders or substations. Therefore, distribution systems are not further considered.

However, all of the emergency service providers that are noted in this Report are connected to specific distribution equipment (e.g., feeders and transformers) and would not receive electricity in the event of a system failure. Therefore, any distribution equipment that serves an emergency service provider could be classified as being critical. Identifying all of Oregon's critical distribution equipment is not feasible and would require access to confidential utility data.

Section 4 provides an additional discussion of legacy and advanced (Smart Grid) based distribution systems and an approach to intelligent routing of electricity to emergency service providers.

Backup Electric Generating Facilities

The objective here is two-fold: (1) identify gaps that may exist between the electrical requirements of emergency service providers and their backup electric generators, and (2) assess the feasibility of using backup generators to create micro-grids. In the context of EAP, micro-grids are a candidate solution to serving the electricity requirements of small groups of customers during a prolonged outage.

Backup generating facilities are commonly found in critical facilities such as hospitals (as noted above), city halls, fire and police stations, public works facilities (e.g., snow removal), and federal government facilities. In addition, backup generators may also be used in commercial or industrial facilities where the effect of an electrical disruption is costly. Backup generators most commonly utilize diesel fuel to generate electricity. The duration of operation varies widely and generally ranges from 12 to 96 hours. The capacity of a backup generator is based on the critical demand that it is intended to serve and are not sufficient to serve any additional electric demands. Backup units of a very small capacity also exist, but their use is limited to providing backup service to traffic signals. Traffic signal backup may be by diesel generators or batteries.

Smart Grid

Today, a vast majority of the Smart Grid assets in Oregon are associated with PGE's AMI project. These assets are dedicated to meter reading functions and do not pertain to the control of the utility system. Consequently, Oregon's existing Smart Grid assets cannot be classified as being critical.

See Section 4 for additional information on Smart Grid.

Natural Gas

Natural gas is an important source of energy supply to Oregon's constituents. It facilitates end-use heating for residences, commercial, and industrial sectors as well as electric energy. Its importance to electric resiliency is noteworthy, as approximately 12 percent of the electricity consumed in Oregon is generated by natural gas-fired plants and represents 29 percent of the electric generating plants that are located in Oregon. In the event of an electric supply-side emergency, natural gas will be an important option for remediation.

Consumption in Oregon

Total natural gas consumption in Oregon has been generally increasing during the past 13 years and reached 240,788 million cubic feet (MMcf) during 2009, as shown below in Figure 1-6 (Natural Gas Consumption by Sector).[36] The most notable increase over this timeframe has been in the electric power market.

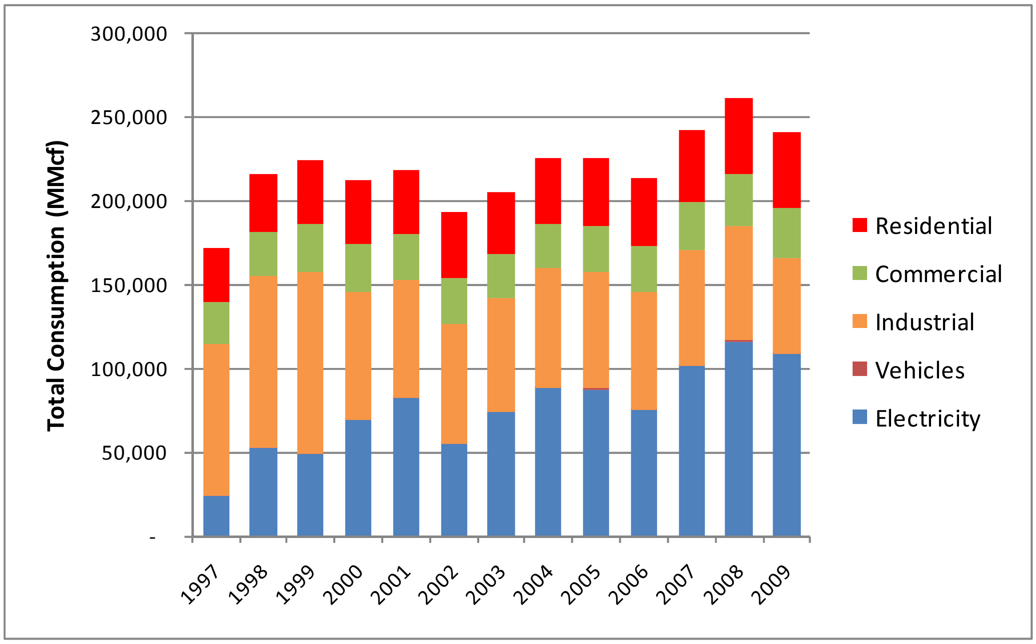

Figure 1-6: Natural Gas Consumption by Sector

[36] U.S. Department of Energy, Energy Information Administration. Specific cite.

Pipelines

Since Oregon's source of natural gas is entirely from out of state, it is important to identify the pipelines and terminals of greatest importance. The major pipelines that supply natural gas in Oregon are shown in Figure 1-7 (Natural Gas Pipelines in Oregon).

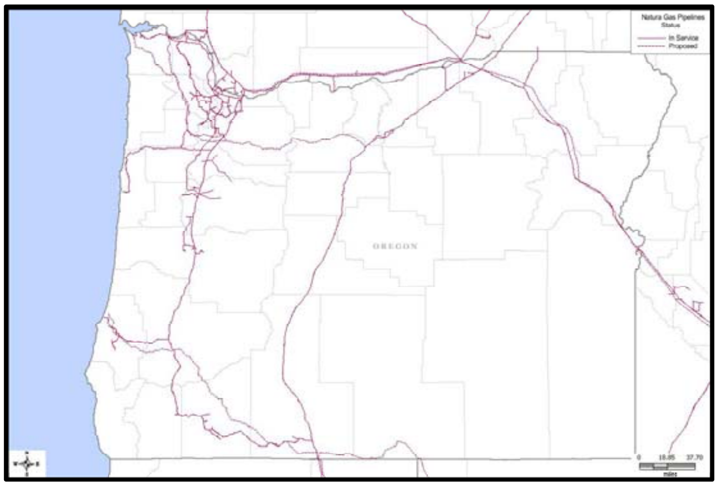

Figure 1-7: Natural Gas Pipelines in Oregon[37]

Not all of the pipelines noted in Figure 1-5 are critical. The criteria used to differentiate between critical and non-critical pipelines, from the perspective of energy resiliency, are its intended applications. Pipeline applications are generally based on the diameter and pressure rating of the pipe. As the diameter and pressure increase, applications become increasingly vital to the region and play a more critical role in energy resiliency. Pipeline applications for different diameters and pressures are summarized in the following table. It should be noted that these data are a "rule of thumb" and that exceptions may occur.

Table 1-13
Pipeline Applications

Application	Diameter (Inches)	Pressure (psi)
Community, Residential and Distribution	3 to 10	Less than 60
Large Commercial	10 to 12	5 to 60
Power Plants	16 to 20	60 to 400
City Gate	10 to 24	60 to 400
Interstate and Major Supply	24 to 42	800 to 1400

The above data indicates that pipelines with a diameter greater than 16 inches are generally critical to Oregon. This assumption has been applied to Oregon's existing pipelines to identify the specific ones that are considered to be critical, as listed in the following table.

[37] Energy Velocity Database, Ventyx Corporation, at http://www.ventyx.com/index.asp

Table 1-14
Oregon Natural Gas Pipelines Greater than 16 Inches[38]

Gas Pipeline Name	Diameter (Inches)	Holding Company Name	Length (Miles)
Gas Transmission Northwest	36	TransCanada Corp	82.61
Gas Transmission Northwest	36	TransCanada Corp	82.60
Gas Transmission Northwest	36	TransCanada Corp	2.56
Gas Transmission Northwest	36	TransCanada Corp	10.69
Gas Transmission Northwest	36	TransCanada Corp	2.57
Gas Transmission Northwest	36	TransCanada Corp	10.69
Gas Transmission Northwest	36	TransCanada Corp	40.70
Gas Transmission Northwest	36	TransCanada Corp	44.54
Gas Transmission Northwest	36	TransCanada Corp	62.60
Gas Transmission Northwest	36	TransCanada Corp	62.64
Gas Transmission Northwest	36	TransCanada Corp	40.69
Gas Transmission Northwest	36	TransCanada Corp	44.52
Gas Transmission Northwest	36	TransCanada Corp	5.48
Gas Transmission Northwest	36	TransCanada Corp	54.44
Gas Transmission Northwest	36	TransCanada Corp	42.95
Gas Transmission Northwest	36	TransCanada Corp	2.77
Gas Transmission Northwest	36	TransCanada Corp	58.67
Gas Transmission Northwest	36	TransCanada Corp	58.68
Gas Transmission Northwest	36	TransCanada Corp	41.98
Gas Transmission Northwest	36	TransCanada Corp	41.98
Pacific Gas & Electric Co	33	PG&E Corp	21.16
Pacific Gas & Electric Co	33	PG&E Corp	21.17
Northwest Pipeline Corp	26	Williams Companies Inc.	72.30
Northwest Pipeline Corp	26	Williams Companies Inc.	70.13
Northwest Pipeline Corp	26	Williams Companies Inc.	18.80
Northwest Pipeline Corp	26	Williams Companies Inc.	16.64
Northwest Pipeline Corp	26	Williams Companies Inc.	40.81
Northwest Pipeline Corp	26	Williams Companies Inc.	10.97
Northwest Pipeline Corp	26	Williams Companies Inc.	62.37
Northwest Pipeline Corp	24	Williams Companies Inc.	36.19
Northwest Pipeline Corp	22	Williams Companies Inc.	1.94
Northwest Pipeline Corp	22	Williams Companies Inc.	0.95
Northwest Pipeline Corp	22	Williams Companies Inc.	6.77
Northwest Pipeline Corp	22	Williams Companies Inc.	6.77
Northwest Pipeline Corp	22	Williams Companies Inc.	7.98
Northwest Pipeline Corp	22	Williams Companies Inc.	34.45

[38] Ibid.

Gas Pipeline Name	Diameter (Inches)	Holding Company Name	Length (Miles)
Northwest Pipeline Corp	22	Williams Companies Inc.	34.46
Northwest Pipeline Corp	22	Williams Companies Inc.	13.97
Northwest Pipeline Corp	22	Williams Companies Inc.	13.95
Northwest Pipeline Corp	22	Williams Companies Inc.	3.76
Northwest Pipeline Corp	22	Williams Companies Inc.	25.25
Northwest Pipeline Corp	22	Williams Companies Inc.	25.59
Northwest Pipeline Corp	22	Williams Companies Inc.	1.48
Northwest Pipeline Corp	22	Williams Companies Inc.	3.77
Northwest Pipeline Corp	22	Williams Companies Inc.	1.51
Northwest Pipeline Corp	22	Williams Companies Inc.	1.75
Northwest Pipeline Corp	22	Williams Companies Inc.	13.43
Northwest Pipeline Corp	22	Williams Companies Inc.	5.52
Northwest Pipeline Corp	22	Williams Companies Inc.	13.39
Northwest Pipeline Corp	22	Williams Companies Inc.	5.53
Northwest Pipeline Corp	22	Williams Companies Inc.	1.75
Northwest Pipeline Corp	22	Williams Companies Inc.	8.10
Northwest Pipeline Corp	22	Williams Companies Inc.	5.24
Northwest Pipeline Corp	22	Williams Companies Inc.	5.24
Northwest Pipeline Corp	22	Williams Companies Inc.	20.50
Northwest Pipeline Corp	22	Williams Companies Inc.	20.62
Northwest Pipeline Corp	22	Williams Companies Inc.	3.77
Northwest Pipeline Corp	22	Williams Companies Inc.	3.77
Northwest Pipeline Corp	22	Williams Companies Inc.	8.09
Northwest Pipeline Corp	22	Williams Companies Inc.	1.38
Northwest Pipeline Corp	22	Williams Companies Inc.	1.40
Northwest Pipeline Corp	22	Williams Companies Inc.	28.74
Northwest Pipeline Corp	22	Williams Companies Inc.	29.06
Northwest Pipeline Corp	22	Williams Companies Inc.	29.07
Northwest Pipeline Corp	22	Williams Companies Inc.	28.72
Northwest Pipeline Corp	22	Williams Companies Inc.	46.52
Northwest Pipeline Corp	22	Williams Companies Inc.	36.19
Northwest Pipeline Corp	22	Williams Companies Inc.	46.52
Tuscarora Gas Transmission	20	Tuscarora Gas Transmission	19.78
Tuscarora Gas Transmission	20	Tuscarora Gas Transmission	1.95
Northwest Pipeline Corp	20	Williams Companies Inc.	19.49
Northwest Pipeline Corp	20	Williams Companies Inc.	21.55

Proposed large-scale natural gas pipeline projects also exist, as listed in the following table. These data show that there are nine proposed projects that have a pipe diameter of 30 inches or greater. If completed, each of these projects could be significant to Oregon's energy resiliency.

Table 1-15
Oregon Natural Gas Pipelines Greater than 16 Inches[39]

Gas Pipeline Name	Diameter (Inches)	Proposed Project Name	Holding Company Name	Length (Miles)
Northern Star Natural Gas LLC	30	Bradwood Landing Pipeline	Northern Star Natural Gas LLC	17.46
Palomar Gas Transmission LLC	36	Palomar Line	Palomar Gas Transmission LLC	3.30
Northern Star Natural Gas LLC	36	Bradwood Landing Pipeline	Northern Star Natural Gas LLC	17.23
Oregon LNG	36	Oregon LNG Transport Pipeline	Oregon LNG	118.97
Palomar Gas Transmission LLC	36	Palomar Line	Palomar Gas Transmission LLC	207.72
Northwest Pipeline Corp	36	Blue Bridge Pipeline Project	Williams Companies Inc	148.05
Ruby Pipeline LLC	42	El Paso Ruby Pipeline Project	El Paso Corp	657.67
Williams Companies Inc (The)	42	Sunstone Pipeline	Williams Companies Inc	575.99
Pacific Connector Gas Pipeline LP	N/A	Pacific Connector	Williams Companies Inc	211.27

Natural Gas Terminals

The principle natural gas terminals are:

- Malin: Interconnects Pacific Gas & Electric (PG&E) GT-NW, PG&E and Tuscarora
- Stanfield: Interconnects Northwest and PG&E GT-NW

However, neither of these two terminals is considered to be a major trading hub on a national scale.

Liquefied Natural Gas

Liquefied Natural Gas (LNG) import facilities are considered to be a significant asset and are commonly classified as being critical. There are two LNG facilities currently in operation in Oregon (NW Portland and Newport), and they are critical facilities. In addition, to meet the growing demand for natural gas, the following LNG import terminals are proposed:

- Astoria, Oregon, 1.5 billion cubic feet per day (Bcfd) (Oregon LNG) – project in federal licensing process
- Bradwood, Oregon, 1.0 Bcfd (Northern Star Natural Gas LLC – Northern Star LNG) – project on hold
- Coos Bay, Oregon, 1.0 Bcfd (Jordan Cove Energy Project) – project in federal licensing process

The list of critical assets will need to be updated if any of these new LNG facilities become operational.

[39] Ibid.

Fuel Supply and Transportation

Emergency managers throughout Oregon joined together to form the Partnership for Disaster Resilience (PDR) for the purpose of conducting risk and vulnerability assessments.[40] The Partnership is broken down into eight geographic regions, as shown in Figure 1-8 (Partnership for Disaster Resilience), below.

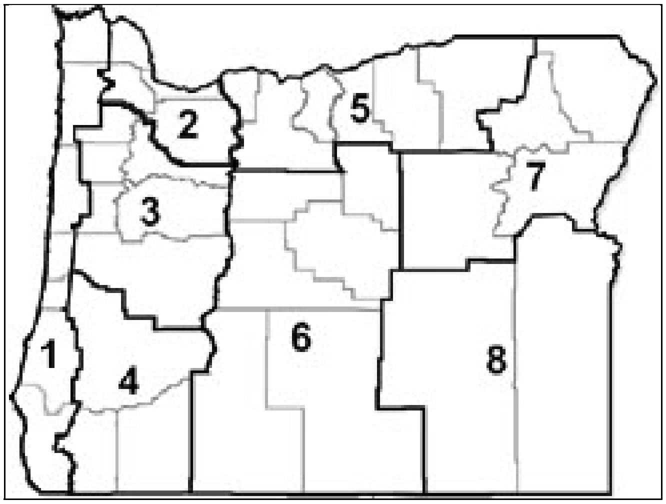

Figure 1-8: Partnership for Disaster Resilience

Each region conducted its own analysis, reports and identification of critical assets that fall into the following categories:

- Roads
- Bridges
- Culverts
- Hospitals
- Fire and rescue
- Police
- Airports

Tables summarizing the above information for the eight regions are found in Appendix A.

Railroads

Railroads are often an important mode of transportation for energy fuels, especially coal. However, since only a small portion of Oregon's electric resource portfolio is coal based, the importance of railroads is somewhat diminished.

The ODOT maintains a map of all key railroads in Oregon, as shown below in Figure 1-9 (Oregon Railroads). The two primary railroads in Oregon that may pertain

[40] Source: http://opdr.uoregon.edu/stateplan/regional

to the transport of coal or other fuels (e.g., bio-fuels) are Burlington Northern and Union Pacific. Interviews with the ODOE indicate that Union Pacific is currently the primary resource for energy-related fuels.

In addition to railroads, highways are also used to transport energy fuels such as, bio-fuels and biomass. Appendix B contains a list of Oregon's critical highways.

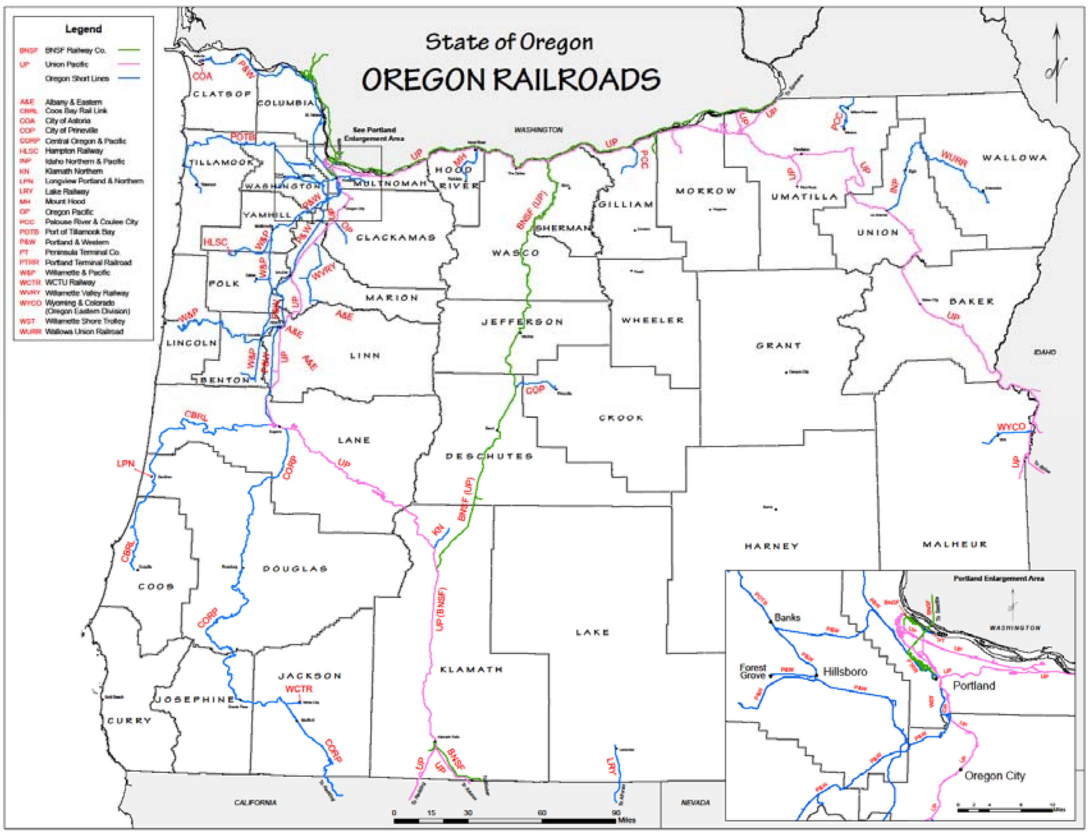

Figure 1-9: Oregon Railroads

Blackstart Operations

A wide-spread emergency could result in the complete loss of electric generation throughout Oregon or the entire Pacific Northwest (e.g., blackout). Under such conditions, regional utilities would need to first establish a certain amount of initial on-line generation to serve as a source of electric power and synchronicity to other electric generating units and then commence system restoration procedures. Initial generating units are referred to as system blackstart generators. Their salient feature is the ability to self-start in the absence of any other electric source or off-site electric power and be able to maintain adequate voltage and frequency while energizing isolated transmission facilities and the auxiliary loads of other electric generators.

In order to guide the restarting of the regional electric grid, the WECC developed a regional Blackstart Capability Plan (BCP).[41] The BCP provides the necessary steps to

[41] "Procedure for Regional Blackstart Capability Plan," Western Electricity Coordinating Council.

ensure that the quantity and locations of blackstart generators are sufficient and accomplish required functionality.

Highlights of the BCP are briefly discussed below. The complete plan and the identity of blackstart generating units is confidential and cannot be listed in this Report.

WECC Blackstart Operations

WECC Operations Staff (Staff) maintains a database of all blackstart generators that are designated for use in restoring the Western Interconnection. Western Interconnection Transmission Operators (TOP) annually provide Staff with updated data on their blackstart generators. The blackstart database is then updated annually by Staff, including the latest test date for each blackstart unit.

Staff annually requests that TOPs provide updated documentation that the blackstart generating units, which are identified in the BCP, can perform their intended restoration functions. Such restoration plans are documented either through simulation or through testing. Staff also annually requests that TOPs provide testing documentation that demonstrates that each blackstart unit can be started and operated without being connected to the interconnected system.

Western Interconnection Transmission Operator and Generator Operator Responsibilities

From the perspective of the EAP in the Pacific Northwest, each TOP and Generator Operator (GOP) is responsible for conducting the following:

- Each TOP provides a System Restoration Plan to the Reliability Coordinator.
- For each blackstart unit, the TOP and GOP shall have in place written blackstart resource agreements, or mutually agreed on procedures or protocols, that specify the terms and conditions of their arrangement. Such agreements shall include blackstart resource testing requirements.
- TOPs or GOPs annually provide Staff with a list of all blackstart generators, including:
  - Generator name
  - Balancing Authority Area
  - Geographic location
  - Capacity (MW)
  - Type of unit (e.g., coal, natural gas, hydro-electric)
  - Latest test date
  - Starting method
- Staff may also request the TOP or GOP provide documentation that demonstrates that the blackstart generators can perform their intended functions as required in the system restoration plan through simulation or testing.

- Staff may also request that the TOP or GOP provide transmission switching diagrams that identify the number, size, and location of system blackstart generating units and the initial transmission switching configuration that is required to start such generators.
- TOPs, GOPs and Staff coordinate their efforts to demonstrate that a minimum of one-third of all blackstart units are tested each year. Every blackstart unit within the Western Interconnection (which includes Oregon) is tested at least once every three years.
- Staff may also request TOP or GOP to provide documentation of test protocols, testing frequency, type of test conducted, and the ability to start the generator when isolated from the system.
- TOP or GOP annually submit their System Restoration Plans to Staff.

The WECC BCP can be a consolidation of all individual TOPs' BCP, which are included in the TOPs' System Restoration Plans and will verify that the number, size, and location of blackstart generators are sufficient to meet overall restoration plan requirements.

Blackstart Capabilities in Oregon

Specific blackstart units, BCP and test-related information in Oregon is confidential. However, there is reason to believe that most of the larger hydropower facilities in the region have blackstart capabilities. Such units are substantial in number and capacity, and are operated by the U.S. Army Corps of Engineers. BPA owns and operates the transmission lines in the Pacific Northwest (OR, MT, ID, WA).

BPA Emergency Response

Incident Management

In accordance with Homeland Security Presidential Directives (HSPD) 5 and 20, the BPA has implemented the National Incident Management System (NIMS) by creating a comprehensive Business Continuity program that includes an integrated system of preplanned procedures and Incident Management Team structures to manage incident response and recovery efforts.

Recognizing the impossibility of developing discrete comprehensive lists of procedures to meet the demands of every conceivable disruptive event; these procedures and teams, which are based upon the Incident Command System (ICS) and Federal Continuity Directives (FCD), create a flexible, scalable framework for responding to events of all magnitude and scope. When disruptive events occur that affect or potentially affect BPA, an Incident Management Team (IMT) is assembled at the appropriate level to manage the agency's response. BPA's incident management plans include managing interactions with other affected entities including our customers and other governmental agencies. A Public Information Officer (PIO), a Liaison Officer (LO) and supporting personnel are part of the IMT when needed, to provide information, obtain input and information from external entities and respond to specific questions and concerns. The PIO is responsible for general information going among others to the public and the media. The LO is responsible for information exchange and coordination among entities that are jointly responding to an incident.

Asset Prioritization

To the extent practicable, BPA transmission system recovery and restoration priorities have been predetermined using BPA's "Priority Pathways" process. This is a repeatable methodology and database for ranking Transmission assets (substations and lines) to support:

- Seismic and other hazards mitigation measures
- Positioning of strategic spare parts
- Systems restoration plans
- NERC CIP[42] Critical Asset identification
- Asset management planning

Overall "Priority Pathways" rankings are based upon:

- Main grid core capabilities, which includes such factors as:
  - System voltages
  - Connection to generation and load service
  - Role in system restoration
- Average seasonal loads
- The assumption that all hazards have an equal probability of occurring (i.e., the risk factor for all events equals 1. This is intended as an evaluation of the impact of the loss of any component upon the operation of the Bulk Electric System, irrespective of the event. Likelihoods and effects of various types of incidents are evaluated separately.),

The use of these priorities is intended to aid in safely and quickly restoring electric service to all customers. However, because priorities must be applied, not all customers will have their service restored concurrently. There are also additional considerations that include the ability of the local utility to deliver electricity to their customers once bulk service, provided by BPA, has been restored to the utility. These concerns are also factored into an incident specific restoration plan.

Recognizing that all events, and their impacts upon the transmission system, are unique; "Priority Pathways" rankings are, at best, a starting point for further analysis, and, thus, they cannot be applied arbitrarily to contingencies or circumstances. The BPA IMT uses these priorities, along with other appropriate factors, in the

[42] NERC is the North American Electric Reliability Corporation which is responsible for oversight of the reliability of the North American electric systems. CIP is "Critical Infrastructure Protection" which is a group of standards to which all North American electric utilities must adhere for the protection of their critical facilities and systems.

development of Incident Action Plans (IAP) throughout the incident. IAPs provide the direction for BPA restoration and response efforts.

System Restoration

Consistent with current NERC reliability standards, BPA has a plan designed to aid in system restoration following significant disruptive or blackout events in the Pacific Northwest power system. The plan defines power system capabilities and limitations under which the system must be operated to ensure safety, to minimize outage time following a system disturbance, and to achieve other desired results. Many of the concepts in this plan also apply to restoration following lesser system disturbances. This plan is not intended to be a rigid step-by-step approach to system restoration. However, the philosophies, concepts, and procedures are well understood and followed during a restoration effort.

If there is damage to equipment, BPA system dispatchers work around the damaged equipment in getting the remainder of the system restored in a manner that achieves this plan's goals. System restoration may be accomplished from either, or both, of BPA's redundant control centers using BPA's communication network.

Typically, the System Restoration Plan is designed to achieve two specific goals:

- Restore a Base Transmission Grid first
- Restore all Northwest electricity loads

A Base Transmission Grid may be built by restoring many small generation-load islands, then tying the islands together. This approach was recently validated in the aftermath of the catastrophic Chilean earthquake. Any generators, including renewable resources, may be used if they can be matched to a load. There are multiple island choices for flexibility in the restoration plan since the type of disturbance may create obstacles to certain paths. To create generation-load islands, electrical transmission paths will be energized from remote generation sources to easily accessible loads. Typically loads will have to be sectionalized into small increments before a Base Transmission Grid can be built. This activity will be done locally by substation operators or remotely by system dispatchers through the Supervisory Control and Data Acquisition (SCADA) system. This will be accomplished in close coordination with other utilities in sectionalizing and restoring loads.

The main concept of the Restoration Plan is that all utilities work independently, yet in a coordinated manner via updates to the WECC[43] Reliability Coordinator so that electrical service is restored to many geographic areas at the same time and/or as soon as possible. Every utility will use their supervisory control facilities and manpower as efficiently as possible to accomplish this objective.

[43] WECC is the Western Electricity Coordinating Council and is the Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

Regional Collaboration

BPA fully appreciates its central role in maintaining the Pacific Northwest's electric grid and providing electricity to our many customer utilities, which, in turn, provide electrical service to the citizens and businesses throughout the Pacific Northwest. To facilitate regional communication and coordination BPA uses its Constituent Account Executives, who work with their state counterparts.

BPA's Constituent Account Executives and primary points-of-contact for the states are:

- Regional Relations Manager:
  Peter Cogswell
  Work: (503) 230-5227; Cell (503) 367-9772
  E-mail: ptcogswell@bpa.gov
- For Idaho:
  John Williams
  Work: (208) 338-3017; Cell: (208) 867-4978
  E-mail: jjwilliams@bpa.gov
- For Montana:
  Gail Kuntz
  Work: (406) 449-5790; Cell: (406) 439-6311
  E-mail: gkkuntz@bpa.gov
- For Oregon:
  John Taves
  Cell: (360) 518-2619
  E-mail: jmtaves@bpa.gov
- For Washington:
  Elizabeth Klumpp
  Work: (360) 943-0157; Cell: (360) 485-2392
  E-mail: ecklumpp@bpa.gov

In the event of significant electricity sector incidents involving BPA, an IMT with a PIO and a LO will be activated at the appropriate level. Immediate communications should be through the PIO for general information and through the LO regarding operational information and coordination of response efforts. BPA's Constituent Account Executives will assist the PIO and LO in exchanging information between BPA's IMT and state officials during such events.

Local governments should communicate through their serving utilities, which are much better positioned to provide the information desired by their constituent local government officials. BPA maintains very close contact with its customer utilities both at the system dispatcher (operational) level and between IMTs so that those customer utilities are active participants with BPA in system restoration plans and execution.

Islanding Capabilities

Certain emergency service providers have the capability to operate as an electrical "island" by self-supplying their own electric requirements during a blackout (the complete loss of electricity). This feature is highly beneficial to energy assurance planning since a second source of electricity facilitates the provisioning of continued emergency services even when the state or remaining region is without electricity.

Example: During a blackout, the loss of electric supply causes communications equipment (base radios) to fail and police and fire stations lose contact with field vehicles. Communications is essential to the effective dispatch of police and fire vehicles.

Islanding or backup capabilities are most commonly achieved by operating on-site diesel generators, which are fueled by on-site storage tanks and designed to meet the facility's critical electric demand. More recently, there has been a growing number of instances where renewable resources have been utilized to provide islanding capabilities. However, it is important to note that the value of such applications may be significantly enhanced by the addition of electric storage, such as batteries.

The critical facilities that are associated with islanding include the backup resources of electricity (e.g., renewables and diesel) and the on-site generators.

Renewable resources are currently being used in Oregon to support the following emergency service providers:

- Klamath Falls, Oregon - geothermal heating for downtown
- Newberg, Oregon – solar voltaic parking canopy for police (feasibility study)[44]
- Joseph, Oregon – solar project for the fire department (feasibility study)[45]

Emergency service providers install backup resources on a case-by-case basis and broad generalizations regarding availability should be avoided.

Oregon's Community Renewable Energy Feasibility Fund (CREFF) program provides grants to fund feasibility studies for renewable energy, heat and fuel projects. Some of these projects provide emergency service providers with an understanding of the benefits and implications of backup supply. The program stated objectives are to encourage the widespread adoption of renewable energy projects that reduce Oregon's dependence on fossil-based energy resources, and, promote sustainable economic development within the state. An additional benefit of the CREFF program is the enhancement of energy resiliency.

[44] http://www.oregon.gov/ENERGY/RENEW/docs/CREFF/10-1563-NewbergARRAEECBG-final_report.pdf?ga=t
[45] http://www.lagrandeobserver.com/News/Local-News/Solar-energy-grants-awarded-to-high-schools-fire-hall?utm_source=twitterfeed&utm_medium=twitter

Section 2
EMERGENCY SERVICE PROVIDERS

Section 2
EMERGENCY SERVICE PROVIDERS

Introduction

The preceding Section identified Oregon's critical electricity assets. The objective of this Section is to expand upon that analysis by identifying the emergency service providers that could be adversely affected by such assets in the event that they became unavailable. The intended methodology that was to be employed here would pursue the following steps:

1. Identify the general classifications of emergency service providers
2. Identify specific emergency service providers
3. Collect data on the energy requirements of emergency service providers
4. Identify the critical infrastructure or facilities that are highest priority for restoring supply
5. Assess the gaps between the emergency energy requirements and backup capabilities

Emergency Service Providers and Priorities of Service

Emergency service providers are generally defined as any entity that affects the safety, health or general economy of Oregon's general population. For the purposes of this Report, the general classifications for emergency service providers include, but are not limited to, the following four tiers of priorities.

Priority 1: Emergency Service Providers

- 911 dispatch centers
- Airports
- Assisted care facilities (e.g., senior citizen facilities, handicap persons facilities, homes of the disabled)
- Communications service providers (e.g., voice, data, Internet, television, cable television, radio)
- Correctional facilities (e.g., jails, prisons)
- Electric utilities (e.g., warehouses and maintenance and repair centers)
- Emergency Operations Centers (EOC)
- Emergency shelters (e.g., designated locations such as schools, religious institutions, recreation centers)
- Fire departments

- Gas stations (if required to serve the petroleum needs of other emergency service providers)
- Health care (e.g., hospitals, ambulance services, and clinics which contain emergency or critical care facilities)
- National Guard facilities
- Oregon Department of Transportation (ODOT) and key transportation asset management facilities
- Other essential county, state, and federal departments
- Police
- Petroleum distribution terminals
- Public works (e.g., snow removal, water, wastewater, street maintenance, traffic signals at priority intersections)
- Railroad operations and crossings
- Red Cross
- Schools (short-term, until all students return home, unless facilities are used as emergency shelters)

The above list is not intended to be exhaustive and some exceptions are anticipated on a county-by-county basis. For example, in some communities, a local church might serve as the central point for emergency food distribution while in other communities that role might be served by City Hall or schools.

Priority 2: Essential Public Services

Second tier entities are important and may also affect Oregon's economy or a considerable number of constituents. However, they are perceived as having a smaller impact on Oregon than Priority 1 entities. Impacts that may be caused by the absence of provisioning, Priority 1 services tend to be immediate and often directly affect the health and safety of Oregonians. In contrast, the impacts associated with the failure to provision the services of Priority 2 entities are less immediate and unlikely to affect health and safety, if at all. Examples of Priority 2 entities include:

- Grocery stores (and other food distribution points)
- Banks and Automated Teller Machines (ATM)
- Gas stations
- Hardware stores (to support local restoration and supply small emergency generators)
- Public works (traffic signals at lower-priority intersections)

Priority 3: Economic Viability

- Largest employers

- Schools

Priority 4: Public at Large

- Medium and small employers
- Residences

During an actual energy emergency declaration by the Governor of Oregon, the PUC and ODOE have statutory authority to curtail energy consumption, including rationing of fuels (electricity, natural gas, petroleum, and all other liquid fuels), if necessary.

Priority Service Issues

In today's energy infrastructure, the ability to selectively provide energy services by priority is severely limited. Electric distribution feeders do not currently have the ability to switch rapidly between withholding and providing electric services to individual customers, based on external priorities. Instead, utilities have employed under- and over-frequency schemes to automatically curtail service to an entire feeder, when justified by special or emergency conditions. This approach switches off service to an entire feeder and all of the customers that are connected to that feeder. Utilities also commonly route distribution feeders to serve customers by geographic area and not by type of customer. This is done primarily for economic purposes.

In the future, the implementation of Smart Grid and AMI may make it feasible to identify customer groups (e.g., priorities) and rapidly curtail service by priority. This is performed by remotely utilizing service switches that are often included in smart meters.[46] Section 4 discusses this approach and the issues that pertain to micro-grids and the use of renewable resources in greater detail.

The absence of widespread smart meter implementation in Oregon (including service switches and the ability of utility operators to make best use of them) suggests that utilities would need to respond to large-scale electric supply-side events by the continued use of traditional methodologies (e.g., SCADA-based or manual feeder switching). In addition, emergency service providers would need to depend on the operation of backup generators, if such units exist.

Specific Emergency Service Providers

This task was initially approached by contacting each of the counties that comprise the state of Oregon. Initial feedback indicated that most counties were eager to participate, but either did not have immediate access to requested data or did not have the staff to collect such data. To work around this obstacle, the Report collected high-level data on the number of emergency service providers that are located in each of the eight PDR Regions. This information is found in Appendix A.

[46] Telephone interview with IPC indicated that its smart meters in Oregon will not have service switches due to its incremental cost. March 11, 2011.

Energy Requirements and Backup Capabilities of Emergency Service Providers

Information about specific emergency service providers and their energy requirements is not available. R. W. Beck, Inc. (R. W. Beck) reviewed the feasibility of using in-house data for typical facilities and finds that typical data provides insight into the energy requirements of some emergency service provider facilities, but does not accurately reflect the characteristics of all such entities since each facility is unique and some locations house multiple functions. For example, a City Hall could contain combinations of Fire, Police, and Public Works Departments. The following discussion provides some typical data on the electric requirements and backup electric capabilities of selected emergency service providers.

Municipal Services

Typical data from other states finds that municipal complexes often have backup diesel generators that are capable of providing emergency electricity for police, fire, and EOC functions. Such generators are designed to support only on-site critical electric services and are not sufficient to backup other entities. The approximate capacity of a municipal generator is 5 kW to 50 kW, with on-site fuel tanks that are large enough to provide electricity for 12 to 48 hours. Municipalities commonly have plans in place to procure additional diesel fuel during the 48-hour emergency period.

Some municipalities have identified their specific road intersections and traffic signals that would be critical during an emergency. Critical traffic signals operate on electricity from local, incumbent electric utilities for day-to-day service, but may also have the capability to receive backup electricity from small diesel generators or batteries. Traffic-related backup generators are approximately 0.1 kW and have fuel tanks that can last for approximately eight hours.

Healthcare

Healthcare-related services, especially large hospitals, represent an important segment of emergency service providers. Hospitals are generally well prepared to withstand a large-scale disruption in electric supply. Their approach to achieving energy resiliency focuses on using on-site diesel generators to serve the electric requirements of selected departments. For example, any department that provides patient care can be served electrically even when the grid is experiencing a blackout.

Achieving energy resiliency has been accomplished, in part, by following the guidance provided by the Joint Commission of Hospital Accreditation (JCHA). In Oregon, the JCHA provides the licensure requirements that are overseen by the Oregon Department of Health. Emergency management is one chapter within the JCHA Program that requires an Emergency Management Program so that safe and effective care can be continued in the event of emergency situations, which arise from natural or man-made disasters. Health care organizations that offer emergency services or are designated as disaster receiving stations must have an Emergency Operations Plan that identifies the hospital’s capabilities and establishes response procedures in the event that the hospital cannot be supported by the local community in its efforts to provide safe and effective care for a period of at least 96 hours.

While accreditation does not require hospitals to stockpile diesel fuel to last for 96 hours of operation, hospitals are required to have a response plan for the first 96 hours after a disaster. If a JCHA evaluation determines that the hospital cannot be electrically self-resilient for 96 hours, then it must have a contingency plan.

The JCHA evaluation requires an assessment of the hospital's capabilities in managing utilities during an emergency and that they identify alternative means of providing the following services:

- Electricity
- Water for consumption and essential care activities
- Water for equipment and sanitary purposes
- Fuel required for building operations, generators, and ambulances
- Medical gas/vacuum systems

Telecommunications

Telecommunications companies are considered to be an emergency service provider because of their role in facilitating essential communications between other emergency agencies.[47] One of the critical assets in telecommunications networks is the Central Office (CO), which serves as a switching point to route voice, data, and video traffic between end-use emergency agencies and service providers. Electricity is critical to nearly every function that takes place within a CO. Consequently, while COs generally utilize the local incumbent electric utility for their day-to-day electric service, they also have backup electric capabilities.

Backup generators at CO sites commonly combine battery backup for up to eight hours and diesel powered units, and have the capability to fully serve the CO for 48 to 72 hours. These backup generators do not have sufficient capacity to serve other, nearby, emergency service providers. During an electric emergency, COs function as an electric island.

Information Technology

Information Technology (IT) is commonly used by emergency service providers to support emergency operations. Since such devices require electricity to operate, electric resiliency is affected by IT services. It is commonplace for cities and states to utilize an Uninterruptable Power Supply (UPS) at their IT and telecommunications departments to provide emergency service for relatively short periods of time (30 to 60 minutes).

[47] Radio communications are also extensively utilized.

Critical Infrastructure for Restoring Supply

There are a number of existing and proposed approaches to restoring energy services to emergency service providers. Today, the most common approach is to install diesel generators at critical locations. This approach is used at hospitals, telecommunications central offices, and many police/fire facilities. The backup capabilities of such generators vary widely and assumptions cannot be realistically made about their sufficiency.

Over time, it is anticipated that there will be a growing interest in installing renewable resources, such as micro-wind turbines or solar panels with battery backup, at emergency service providers. Consider the following case studies:

- Coos Bay, Oregon (December 2010): Fire Station No. 1 installed a 23.6-kilowatt hour (kWh) solar photovoltaic system at an installed cost of $111,000.
- Joseph Fire Department: solar grant - $49,280
- Blue Mountain Hospital District, Grant County: pellet boiler grant - $40,000
- East Oregon Correctional Institution, Umatilla County: Solar $450,000

Section 3
VULNERABILITY AND RISK ASSESSMENT

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Section 3
VULNERABILITY AND RISK ASSESSMENT

Introduction

Section 1 contains extensive lists of energy assets that directly serve the state of Oregon. However, not all of these assets are equally vulnerable or critical from the perspective of Oregon's energy assurance plans. Consequently, this Section further examines such information to identify existing and potential risks and vulnerabilities that could significantly impact key assets or infrastructure. The deliverable of this Task is the identification of potential risks and vulnerabilities to integrate renewable resources into delivery and supply chains.

The state of Oregon, and especially ODOE, is responsible for developing and administering programs related to energy emergencies with the overall objective of protecting the health, safety, and welfare of the state's citizens. Its overall goals include minimizing the impact of energy supply shortfalls and the resulting economic hardships on citizens, institutions and private enterprise, and preventing the possibility of a more serious energy supply shortage. Meeting these goals is generally referred to as providing energy assurance.

Achieving the goals of energy assurance focuses heavily on building plans. Such plans are based on current information and are dynamic over time. It is essential for state officials to have a sound idea of how key energy providers will manage energy emergencies that could lead to shortages, especially whom to contact for real time information on incidents, estimated impacts, and short- and long-term restoration. This Report provides Oregon with a broad picture of its energy vulnerabilities and risks.

The Oregon EAP is expected to provide state energy stakeholders with a guide to managing potential energy deficiencies and disruption. It contains specific information about Oregon's electric energy sector, critical assets, and vulnerabilities. The process generally follows the following three steps:

- First, broadly inventory energy assets
- Second, screen those assets by established criteria to identify the ones that are most critical
- Third, evaluate the risk and consequences of asset failure or disruption

This information facilitates ODOE's prioritization of energy assurance measures that the state and energy industries could implement to alleviate the impact of supply loss within and across various resources.

Objectives

The primary objective of vulnerability/risk analysis is to gain valuable insight into the potential consequences associated with the loss of the state's most critical energy assets and to identify potential risks/vulnerabilities to integrate renewable resources into delivery and supply chains. The analysis provides policy makers with the tools to improve energy infrastructure resiliency.

Energy Asset Inventory: Inventory the major energy assets within Oregon, such as hydroelectric generators, electric transmission, natural gas, and bio-fuels. This study focuses on critical energy assets whose loss could cause significant disruptions in the supply and distribution of energy. This step is presented in Section 1.

Critical Asset Assessment: Distill broad groups of energy assets down to the ones that are most critical to Oregon, based on a set of criteria for impact (consequence), frequency (probability), available mitigation, and combinations of the two. This step is presented in Sections 1 and 3.

Vulnerability and Risk Assessment: Based on the identification of critical assets, this step assesses the overall vulnerability and risk for each critical asset. Additionally, it identifies potential risks and vulnerabilities to integrated renewable resources into delivery and supply chains, as found in this Section.

It should be noted that energy infrastructure is often highly interdependent, that common mode events can occur, and that the integration of renewable resources or smart grid to assist in energy resiliency has not been tested. Weather-related events such as an extended period of low participation, coupled with above normal temperatures, could have compounding impacts. This scenario would result in an increase in electric demand and energy requirements (e.g., increased air conditioning) simultaneous to a decrease in available resources (e.g., depleted hydroelectric capacity).

Inventory of Critical Assets

The asset inventory is the foundation of risk assessment. The results of this Report's inventory are found in Section 1 and focus on certain physical elements of the energy supply system for each major resource. This information has been drawn from a variety of industry, state, and federal sources. All of which are publicly available; no confidential information is found in this Report.

Scoring Critical Assets

For the purposes of energy assurance, critical assets are defined as those components of energy infrastructure that are vital and that their destruction would have a debilitating impact on the state's health, economy, and general way of life. Alternatively, it is also defined as those renewable resources that could assist (or are critical in assisting) energy resiliency during an energy emergency.

The approach utilized here is consistent with U.S. DOE guidelines,[48] and the results are later compared to the critical assets already identified by the Department of Homeland Security and those critical assets already inventoried by the Department of Energy.

Screening Criteria – Consequence or Impact

The consequence or impact that is associated with the loss or damage to each asset is scored as follows:

Negligible or Local: The impacts associated with the damage or relatively long-term loss of each asset is limited to a local area (e.g., city or county). The score of such consequences is a 1.

Significant or Statewide: The impacts associated with the damage or relatively long-term loss of each asset may affect the entire state. The score of such consequence is a 3.

Crisis, Regional or National: The impacts associated with the damage or relatively long-term loss of each asset may extend beyond Oregon's borders and affect a broader region. The score of such consequences is a 5.

The preceding scores intentionally leave gaps (e.g., scores of 2 and 4) in order to account for potential intermediate levels of importance.

The ability of renewable resources or Smart Grid in alleviating energy emergencies or enhancing energy resiliency was also considered.

Screening Criteria – Likelihood or Probability

The likelihood or probability that is associated with the loss or damage of each asset or its contribution to resiliency (in the case of renewable energy and Smart Grid) is scored as follows:

Very Low or Rare: Historical evidence or opinion indicates that the likelihood of such events is rare (e.g., less than 10 percent). The score of such probability is a 1.

Moderate or Likely: Historical evidence or opinion indicates that the likelihood of such events is likely, though does not occur very often (e.g., 26 percent to 74 percent). The score of such probability is a 3.

Very High or Common: Historical evidence or opinion indicates that the likelihood of such events is common (e.g., greater than 90 percent). The score of such probability is a 5.

As noted above, gaps are intentional to allow for intermediate grading.

Screening Criteria – Mitigation

The ability or expected success of mitigating risks can vary significantly. For example, an event could be common and of high impact, yet easily and effectively

[48] "Risk Management Guide," U.S. Department of Energy, Document 413.3-7, dated September 16, 2008.

mitigated. Alternatively, some events are very difficult to mitigate (e.g., seismic), regardless of their consequence or probability. Consequently, it is necessary to include a measure for mitigation, as scored below:

Highly Successful: Historical evidence or opinion indicates that the risk owner's ability to effectively mitigate the damage or long-term loss of the asset is highly successful. The score of such mitigation is a 1.

Moderately Successful: Historical evidence or opinion indicates that the risk owner's ability to effectively mitigate the damage or long-term loss of the asset is moderately successful. The score of such mitigation is a 3.

Unsuccessful or Unknown: Historical evidence or opinion indicates that the risk owner's ability to effectively mitigate the damage or long-term loss of the asset is unknown or has been generally limited. The score of such mitigation is a 5.

In the case of renewable resources or Smart Grid, their mitigating properties are largely untested. The same scoring as above is used, but it is largely based on an expert's opinion on how those assets should perform in an energy emergency or contribute to resiliency.

Overall Risk Score

Creating an overall Risk Score is conducted in three steps. The first step applies the combination of the preceding Probability and Consequence scores to the U.S. DOE's matrix, which is shown below in Figure 3-1 (Risk Analysis Matrix). This step results in an initial Risk Score. The second step provides further differentiation between critical assets by accounting for each risk's Mitigation score. The final step prioritizes risks and vulnerabilities to identify the assets of greatest importance, and, the risks and vulnerabilities that confront the integration of renewable resources into delivery and supply chains.

Events that have relatively higher overall Risk Scores are generally characterized by the following attributes:

- Impact significant market dominance or capacity
- Affect a relatively large number of constituents
- Affect constituents that are considered to be sensitive
- Impact specific locations that are significant
- Cause economic impacts that are wide-spread and long-lived
- Require mitigation measures that are expensive, ineffective or unproven

Most importantly, these attributes are not mutually exclusive and combinations of relatively moderate effects could result in a high overall score.

Consequence						
Probability		Negligible (Grade 1)	Marginal (Grade 2)	Significant (Grade 3)	Critical (Grade 4)	Crisis (Grade 5)
	Very High >90% (Grade 5)	Low	Moderate	High	High	High
	High 75% to 90% (Grade 4)	Low	Moderate	Moderate	High	High
	Moderate 26% to 74% (Grade 3)	Low	Low	Moderate	Moderate	High
	Low 10% to 25% (Grade 2)	Low	Low	Low	Moderate	Moderate
	Very Low <10% (Grade 1)	Low	Low	Low	Low	Moderate

Figure 3-1: Risk Analysis Matrix

Results – Energy Sector Analysis

The results of Oregon's critical asset screening is first examined from a top-down perspective to create a high-level overview of criticality by key energy sectors, as based upon the consequence of disruption, loss or contribution during an energy disruption. Table 3-1 (Energy Sector Criticality and Vulnerability), below, summarizes our findings and codes the relative importance of each attribute. As an example, the loss of one of the major gas pipelines into the state would have major consequences (High) given the high market dominance and large customer base, but ranks low (Low) in terms of its historical record of high reliability.

Table 3-1
Energy Sector Criticality and Vulnerability

CATEGORY	Market Dominance/ Relative Capacity	Number of Customers Served	Strategic Location	Seasonal Vulnerability	Degree of Redundancy	Historical Evidence of Disruption
Electric Generation (Conventional without Hydroelectric)	Low	Low	High	High	Medium	Low
Hydroelectric Generation	High	High	High	High	Medium	Low
Renewable Electric Resources	Low	Low	High	High	Medium	Medium
Electricity Transmission	Low	Low	High	Low	Medium	Low
Natural Gas Transmission/ Pipelines	High	High	Low	High	High	Low

Results – Critical Asset Analysis

Next, we examine the Risk Scores for Oregon's specific critical assets. Not all of Oregon's energy-related assets are equally critical. Table 3-2 (Asset Inventory Summary) includes only those assets that are relatively more important to the energy assurance planning process and omits electric energy resources that have a capacity of less than 100 MW.

Table 3-2
Asset Inventory Summary

Conventional Electric Resources	Resource	Capacity (MW)	Impact	Probability	Mitigation	Overall Score
Hermiston	Nat. Gas	689	5	2	2	High
Boardman	Coal	601	5	2	2	High
Beaver 1 - 7	Nat. Gas	586	5	2	2	High
Klamath Cogen.	Nat. Gas	502	5	2	2	High
Port Westward	Nat. Gas	399	4	2	2	Medium
Coyote Springs 2	Nat. Gas	287	3	2	2	Medium
Coyote Springs 1	Nat. Gas	266	3	2	2	Medium
Hermiston Gen.	Nat. Gas	235	3	2	2	Medium
SP Newsprint	Nat. Gas	163	2	2	2	Low

Hydroelectric Resources	Resource	Capacity (MW)	Impact	Probability	Mitigation	Overall Score
John Day	Hydro	2,160	5	2	2	High
The Dalles	Hydro	1,808	5	2	2	High
Bonneville	Hydro	1,077	5	2	2	High
McNary Fishway Hydro Project	Hydro	980	5	2	2	High
Lookout Point 1 - 3	Hydro	120	4	2	2	Medium
Carmen-Smith 1-3	Hydro	114	4	2	2	Medium
Pelton 1- 3	Hydro	110	4	2	2	Medium
Detroit 1 & 2	Hydro	100	4	2	2	Medium
Renewable Resources	Resource	Capacity (MW)	Impact	Probability	Mitigation	Overall Score
Biglow Canyon	Wind	450	3	4	5	Low
Klondike	Wind	399	3	4	5	Low
Weyerhaeuser	Bio-Fuel	134	2	5	5	Low
Vansycle	Wind	124	2	5	5	Low
Elk Horn Valley	Wind	104	2	5	5	Low
Electric Transmission						
Voltage	Circuit Miles	Impact		Probability	Mitigation	Overall Score
1000 kV	264	5		2	2	Medium
500 kV	4,734	5		2	2	Medium
345 kV	570	5		2	2	Medium
287 kV	227	4		2	2	Medium
230 kV	5,319	4		2	2	Medium
161 kV	119	3		2	2	Medium
138 kV	50	3		2	2	Medium
115 kV	3,556	3		2	2	Medium
Natural Gas						
Pipeline	Capacity	Impact		Probability	Mitigation	Overall Score
Northwest Pipeline		5		2	3	Medium
PG&E Gas Transmission		5		2	3	Medium
Malin Terminal		5		2	3	Medium
Stanfield Terminal		5		2	3	Medium

Results – Potential Risks and Vulnerabilities

There are numerous, specific potential risks and vulnerabilities that are unique to Oregon that could significantly impact integrating renewable resources into delivery and supply chains. Alternatively, there are numerous renewable resources and smart grid assets that once integrated properly, may positively impact energy resilience. The following discussion addresses each such risk and vulnerability, and provides a summary of their Risk Scores.

Technical Compliance

The integration of renewable resources into Oregon's transmission grid requires the execution of an interconnection agreement and compliance with the interconnection requirements that are stipulated by such agreements.[49] The foundation for the technical requirements of such interconnections are commonly based on the Institute of Electrical and Electronics Engineers' (IEEE), "Standard for Interconnecting Distributed Resources with Electric Power Systems" (IEEE Standard 1547, dated July 28, 2003), and FERC Orders No. 2006-B (small generators) and 2003-C (large generators).[50] The IEEE Standard is discussed in greater detail in Section 4 of this Report and finds that technical interconnection requirements are voluminous and may serve as an obstacle to some renewable energy projects.

Emergency Operating Procedures

Large-scale electric system emergencies may require the use of blackstart generating units to re-initialize the generation and transmission systems. In Oregon, such units are almost always hydroelectric facilities.[51] Conversations with BPA and PacifiCorp staff confirm that renewable resources are not included in such processes and that their re-insertion into the grid occurs as a last step. Renewable resources are not dispatchable and, therefore, are the last to come online in a grid stabilizing effort.

Energy and Capacity Storage

The capacity factor for conventional, base-load resources are commonly greater than 80 percent. In contrast, capacity factors for wind turbines and solar resources are approximately 35 percent and 15 percent, respectively. These data support claims by utilities that renewable resources cannot be relied upon to operate when needed since they are not dispatchable. One approach to abetting this issue is to implement electric storage devices (e.g., batteries, pumped hydro, flywheels, compressed air). Electric storage increases the availability of renewable resources, effectively increasing their capacity factor and the hours per year when such units are dispatchable. Capacity factor improvements would cause renewable resources to be more comparable to conventional resources, make them more useful during energy emergencies, and improve Oregon's energy resiliency.

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[49] Sample agreements can be found at http://www.ferc.gov/industries/electric/Indus-act/gi.asp
[50] FERC Order No. 2006-B (July 20, 2006) as 71 FR 42587 and FERC Order 2003-C.
[51] BPA and PacifiCorp staff declined to provide the names of specific blackstart generating units.

Grid Interconnections and Improvements

The development of new renewable resources, such as wind farms, is commonly located in rural or remote areas where the existing electric grid (e.g., transmission lines and substations) is either nonexistent or insufficient to accommodate the delivery of new sources of energy. Consequently, such new projects commonly raise concerns about grid interconnections and grid improvements. Grid interconnections are a direct consequence of the new resource and generally focus on the construction of new transmission lines and substations to reliably deliver such energy to the grid. Separately, the insertion of new resources into the grid often causes the need to upgrade other, existing grid elements (e.g., transmission lines). Grid improvements are indirect in nature and might include the upgrading of existing grid elements or the addition of new elements. In most cases, the resolution of concerns regarding grid interconnection and grid improvements are costly, affect the economic viability of developing new renewable resources, and may inordinately impact the rate base.

It should be noted that such grid effects are not limited to renewable resources and that economic implications also affect the development of new conventional resources.

Environmental Impact

In addition to the above capital costs of new transmission lines, there have been cases where impediments also stem from the environmental impact that is associated with new transmission lines. Preparing studies and evaluations of environmental impact requires human resources, construction lead-time, and expense. In general, the cost of environmental permitting is approximately 10 percent of the total project cost.

Lack of Regulatory Vision

Smart Grid technologies have the potential to enhance the integration of renewable resources.[52] [53] Consequently, promoting the implementation of Smart Grid throughout Oregon could increase the utilization of renewable resources. However, Oregon does not have a coherent vision for the promotion of Smart Grid technologies. The adoption of a statewide plan for promoting Smart Grid implementation may positively impact renewable resources and thereby improve electric resiliency, as noted elsewhere in this Report.

At the federal level, some American Recovery and Reinvestment Act (ARRA) funds were made available to certain electric utilities for Smart Grid related implementations in Oregon.

- Central Lincoln People's Utility District: $9,894,450 was made available to provide two-way communication between the utility and all of its 38,000 customers through a Smart Grid network and other in-home energy management tools.

[52] http://www.idahopower.com/AboutUs/CompanyInformation/SmartGrid/FAQs.cfm
[53] "Investigating Smart Grid Solutions to Integrate Renewable Sources of Energy into the Electric Transmission Grid," Battelle Energy Technology, 2009.

- Idaho Power Company: $47,000,000 was made available to deploy a Smart Grid network (AMI, two-way communications) for most of its 475,000 customers (most notably the implementation of AMI).

Transmission Reliability

Potential risks and vulnerabilities to integrating renewable resources into delivery and supply chains are also found in the reliability of transmission systems. Transmission paths in Oregon are congested, causing multiple lines to be routed in close proximity to each other.[54] One report has identified transmission congestion as a primary risk in Oregon, which adversely affects the supply chain for renewable resources.[55]

In addition, renewable resources are commonly interconnected by single, radial transmission lines. The loss of any such line would then curtail all imports from such resources.[56]

Weather

Oregon's weather is not always conducive to the operation or integration of certain renewable resources. Ice storms and severe winds have resulted in transmission lines failures that affect renewable resource integration. Wind has caused trees to come into contact with transmission lines.

It is estimated that wind gusts of up to 150 miles per hour (mph) and sustained speeds of 110 mph may occur every 5 to 10 years. Significant windstorms on record in Oregon include:[57]

- January 9, 1880: Portland, sustained south wind speeds of 60 mph.
- January 20, 1921: Astoria, unofficially, reported wind gusts up to 130 mph. Hurricane-force winds were reported along the entire Oregon and Washington coasts.
- April 21-22, 1931: Strong northeast winds caused widespread damage.
- November 10-11, 1951: Sustained southerly to southwesterly winds of 40 to 60 mph occurred over nearly the entire state, with gusts of 75 to 80 mph.
- December 21-23, 1955: High winds were felt across most of the state. North Bend reported sustained wind speeds of 70 mph with gusts to 90 mph.
- November 3, 1958: Sustained wind speeds of 51 mph with gusts to 70 mph were reported at the Portland airport.

[54] "National Electric Transmission Congestion Study," U. S. Department of Energy, dated December 2009 and "Challenge for the Northwest, Protecting and Managing an Increasingly Congested Transmission System," Bonneville Power Administration, April 2006.
[55] Ibid.
[56] Conversations with Iberdrola, 2011.
[57] "Oregon Emergency Operations Plan, Incident Annex IA-7 (Severe Weather)," Oregon Emergency Management, June 2010, http://www.oregon.gov/OMD/OEM/plans_train/docs/eop/eop_ia_7_severe_weather.pdf

- October 12, 1962: The "Columbus Day Storm" was the most destructive wind storm to ever occur in Oregon. Monetary losses in the state were placed at $175 to $200 million. There were 38 fatalities and many more injuries. Hundreds of thousands of homes were without power for several hours, with many power outages lasting two to three weeks.
- October 2, 1967: Highest winds recorded since the Columbus Day Storm of 1962. Wind speeds of 100 to 115 mph were unofficially recorded along the Oregon coast.
- March 25-26, 1971: Peak wind gusts were 50 to 84 mph.
- November 13-15, 1981: The strongest wind storm since the Columbus Day Storm of 1962. Wind gusts as high as 92 mph were recorded. Eleven people were killed and $50 million in damage were reported.

Seismic Activity

Earthquakes can significantly affect renewable resources and the grid that interconnects them. There are three different sources for earthquakes in the Pacific Northwest: the Cascadia Subduction Zone, Benioff Zone, and shallow crustal earthquake activity.

DOGAMI is evaluating the impacts of earthquakes in Oregon and its report should be reviewed for additional information.[58]

High Levels of Precipitation or Runoff

Periods of high spring runoff or above normal precipitation in the Pacific Northwest could result in a surplus of hydroelectric energy and capacity. Such periods may be coupled with low regional market prices for electricity. These events could adversely impact the financial viability of renewable energy producers (e.g., avoided cost pricing).

To illustrate this point, during June 2010, BPA and the Federal Columbia River Power System faced a temporary oversupply of generation from surging spring runoff, wind power, and thermal power.[59] The outcome was a lack of market for federal hydropower, even at zero cost. Thermal power plant operators normally save money if they displace their fuel with lower-cost hydropower. However, wind power projects that receive Federal Production Tax Credits (PTC) and/or state Renewable Energy Credits (REC) have an economic incentive to generate as much as possible, regardless of reliability constraints. BPA reports that the PTC is currently $21 per MWh and state RECs are generally about $20 per MWh.[60] The June 2010 high-water event occurred in an otherwise low-water year and similar conditions could persist for one to three months in a normal or high-water year.[61]

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[58] "Oregon State Energy Assurance Plan," Oregon Department of Energy, Oregon Public Utility Commission, March 2011.
[59] "Statement on Environmental Redispatch and Negative Pricing," Bonneville Power Administration, December 3, 2010.
[60] Ibid.
[61] Ibid.

Critical Infrastructure Protection

BPA is responsible for much of the region's hydroelectric facilities and transmission system. The bulk transmission system is planned and designed to meet numerous standards, including the NERC CIP. The U.S. DOE conducted an audit of BPA's critical infrastructure in 2003 and 2010 and discovered the following:[62]

- In 2003, BPA had initiated, but not yet completed, vulnerability and risk assessments.
- In February 2010, BPA had not completed assessments on 24 of its 60 critical assets. Of the 36 assessments that had been completed, 32 had been done over four years ago.
- In 2007, BPA had identified the lack of testing as a problem in an assessment of its highest ranked critical assets and noted that without a testing program, security effectiveness could only be subjectively estimated.
- In 2009, BPA again identified the lack of a performance testing program.
- In 2010, BPA had not, for the most part, implemented a major physical control system (e.g., electronic perimeter intrusion motion detection and alarms).

The above findings from the U.S. DOE suggest that the transmission grid in the Pacific Northwest is exposed to physical risk. Such CIP-related risk translates into potential threats to the transmission interconnections that facilitate the renewable energy supply chain. Failures in that supply chain will result in the loss of renewable energy resources (capacity and energy) in Oregon.

Terrorist Attacks

The above discussion regarding CIP risks also pertain to hypothetical attacks from terrorists. Various dams along the Columbia River are perceived to be potential targets to terrorists.[63] [64] [65]

Summary

The above risks and vulnerabilities, which impact the integration of renewable resources into delivery and supply chains, are summarized in Table 3-3 (Summary of Risks and Vulnerabilities).

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[62] "Audit Report – Report on Critical Asset Vulnerability and Risk Assessments at the Power Marketing Administrations," U.S. Department of Energy, October 2010, DOE/IG-0842.

[63] http://www.waterencyclopedia.com/Re-St/Security-and-Water.html

[64] http://www.nwhydro.org/resources/laws_regulations/dam_safety_security.htm

[65] http://www.ferc.gov/legal/maj-ord-reg/land-docs/ceii-rule.asp

Table 3-3
Summary of Risks and Vulnerabilities

CATEGORY	Potential Impact or Severity	Probability (Historical Evidence of Disruption)	Available Mitigation Measures	Impact on Renewable Resources	Overall Risk Score
Technical Compliance	Medium	Medium	Low	Medium	Medium
Emergency Operating Procedures	Medium	High	High	Medium	Medium
Energy and Capacity Storage	High	Medium	High	Medium	Medium
New Transmission and Substations	High	High	Medium	High	High
Environmental Impact	Medium	Medium	Medium	Medium	Medium
Regulatory Vision	Low	Medium	Low	Medium	Low
Transmission Reliability	High	Medium	High	Medium	Medium
Weather	Medium	High	High	Medium	Medium
Seismic	High	High	High	High	High
High Precipitation	Medium	Medium	High	Medium	Medium
Critical Infrastructure Protection	High	Medium	Medium	High	Medium
Terrorist Attacks	High	Low	Medium	Low	Medium

Section 4
INTEGRATION OF RENEWABLE ENERGY AND SMART GRID TECHNOLOGIES

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Section 4
INTEGRATION OF RENEWABLE ENERGY AND SMART GRID TECHNOLOGIES

Introduction

This Section of the Report examines integration of Smart Grid applications, renewable and distributed energy resources into electric delivery, and supply chains. The discussion contained in this Section accomplishes this requirement and specifically addresses each of its subtasks, as delineated below.

- Identify/assess Smart Grid technologies to improve the resiliency of energy infrastructure including the effectiveness of distributed renewable resources.
- Identify options for the intelligent routing of electric power to key installations.

Identify options for integrating renewable resources into existing grids, and improve existing delivery and supply chains. Key findings of this review include:

- In general, Smart Grid technologies can be beneficial to the integration of renewable resources and could improve Oregon's electric resiliency.
- Oregon's EAP should promote the use of renewable resources to enhance energy resiliency.
- Oregon's largest utilities have no existing plans to utilize Smart Grid technologies or renewable resources to mitigate electric emergencies. An exception is Central Lincoln People's Utility District (CLP), which is using ARRA funds to implement two-way communications with its customers.

Smart Grid related applications at Oregon's largest utilities focus solely on AMI (e.g., cost effective means to meter reading). In the case of PGE, with their AMI deployment completed, they are beginning to implement more advanced applications (e.g., distribution automation, switching, load management, outage management). Other electric operators, given the nature of their service territory being more rural in nature, are not yet looking into a full AMI deployment in their Oregon service territories.

Smart Grid Overview

The following discussion presents a platform for understanding what is meant by "Smart Grid," its functionality, and how it can be used to enable Oregon's EAP and the integration of renewable and distributed generators. This discussion is followed by a review of the status of Smart Grid at the largest electric utilities in Oregon.

The term Smart Grid generally refers to the modernization of the existing electric grid to maintain or improve the reliability and security of the system, meet future growth, and improve its economic efficiency.[66] The U.S. DOE broadly defined Smart Grid as being comprised of key principal characteristics to serve as the focal point for developing new strategies for grid research, technology development, regulation, integration, operation, maintenance, and asset management. They are briefly described as follows:[67]

- Self-healing: The modern grid will perform continuous self-assessments to detect, analyze, respond, and quickly restore grid components or network sections. Self-healing functionality will help maintain grid reliability, security, affordability, power quality, and efficiency.
- Consumer participation: Motivates and includes consumers' participation in electricity markets, bringing tangible benefits both to the individual consumer and to overall system reliability.
- Resiliency: Resists cyber attacks by including security functions to obtain a system-wide solution that will reduce physical and cyber vulnerabilities and recover rapidly from disruptions.
- Power quality: The modern grid will provide the quality of power desired by today's users, as reflected in emerging industry standards.
- Accommodate generation and storage options: Integrate many different types of electrical generation and storage systems with a simplified interconnection process.
- Enable electric markets: Support open-access markets, and expose and shed inefficiencies.

Overall, the U.S. DOE anticipates that the future grid's information technology will be able to provide detailed awareness of the factors that affect the supply and demand in electricity markets. The modern grid will also improve the connectivity between buyers and sellers of electricity.

An important difference between existing systems and the next generation of grid management systems is characterized by a two-way flow of electricity and information that creates an automated and widely distributed electric network. It will monitor, protect, and automatically optimize the operation of its interconnected components. This includes central, distributed electric generation resources, and the high-voltage transmission and distribution system to industrial users and commercial building automation systems; to energy storage installations; and to residential consumers with their thermostats, electric vehicles, appliances, and other household devices.

Smart Grids will incorporate information technology, sensors, and distributed computing to collect and analyze data to deliver real-time information. This information will be used to instantly match electricity demand with supply from all available sources, incorporating both traditional generation and wind, solar, and

[66] "Report to NIST on the Smart Grid Interoperability Standards Roadmap," Electric Power Research Institute, June 2009.

[67] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability and Energy Independence and Security Act of 2007.

electricity storage. The Smart Grid will enable a "just in time" balance of supply and demand at the distribution device level.

The Smart Grid is still in a developmental stage and its final architecture, functionality, and accomplishments may be evolutionary. This is due, in part, to the fact that a Smart Grid is not a specifically defined end-point, but rather a spectrum of opportunities, where each point along the spectrum represents a unique set of capabilities (e.g., benefits) and roll-out requirements (e.g., cost being a significant factor). Moreover, the "appropriate" place on the spectrum may be unique for each utility; one solution may not be economically prudent for all of Oregon's utilities.

Smart Grid systems are forecasted to produce many valuable benefits, some of which could directly affect the resiliency of Oregon's electric grid and disaster recovery, including:

- Automate electric supply system to facilitate improvements in reliability and availability of electric service.
- Improve the resilience to events, such as solar and seismic events, equipment failures, and sabotage.
- Improve the quality and diversity of energy services.
- Facilitate the coordination of supply system capacity to receive power from renewable and variable sources.
- Improve the diversity and distribution of electric resources.

The preceding list suggests that Smart Grid holds the potential to be a very productive resource for electric reliability in the long term. The most substantial part of Smart Grid now being deployed is AMI. Within five years, AMI is forecasted to facilitate rapid discovery and management of electric outages, and will support new rates structures that enable utilities and their customers to timely manage demand in response to dynamic changes in electric markets and grid operating conditions.

Some progress toward these goals can be enabled in Oregon immediately upon deployment of hardware and operating software. Integration of the many Smart Grid systems will take longer and will be needed to achieve further benefit. In addition, the new Smart Grid capabilities raise many policy and operating issues that will have to be resolved to fully realize the potential benefits.

Full Deployment

The concept of a fully deployed Smart Grid is that integrating modern sensing, communication, and automation with the existing electric grid will enable many new and favorable capabilities and features. Widely publicized examples include improved reliability (e.g., fewer and shorter service outages), greater resilience in the face of challenges, ability to accommodate substantial amounts of renewable and distributed generation, lower electric losses, higher power quality (e.g., reduction in harmonics), and a reduction in environmental impacts (e.g., reduction in emissions, fewer capital projects).

Sensing will be by revenue meters (AMI), voltage sensors, current sensors, and a wide range of other devices. Communication will be by radio, power line, optical fiber, and other methods. In addition, automation will encompass the full range that can be implemented, now and in the future, using computers distributed throughout the electric grid.

Information provided by sensing, communication, and automation will enable utilities to automate certain functions that are currently manual, labor or time intensive. Examples include detecting problems before they result in outages, executing switching actions that restore service promptly in certain outages, and managing voltage and current all the time to minimize technical losses.

Integrating Renewable Resources and Distributed Generators

Some renewable or distributed resources, notably photovoltaic (PV) solar and wind, are subject to uncontrollable variations, which directly affect electric generation. Stability of the grid requires that supply and load remain equal. If an appreciable fraction of the present load is served by solar generation, and the sun is suddenly covered by a cloud, the grid may become unstable if other supplies are not engaged immediately or load is not reduced to match the reduced supply.

The balance of generation and load is managed dynamically. Conventional peaking units (simple cycle) may require approximately 30 minutes to come on-line to meet variable load requirements and provide some measure of voltage support. However, clouds could block a distributed solar array in much less than five minutes. In such events, if clouds were to suddenly choke off solar PV supply, Smart Grid applications will allow utilities to respond more dynamically than now to:

- Engage stored supply, such as batteries.
- Control customer loads, such as water heaters, pool pumps, and air conditioners.

Additional discussion of the obstacles and requirements that are associated with resource integration is found later in this Section.

Emergency Response

The current generation of smart meters includes service switches in all residential (and many small business) meters. The utility can remotely connect or disconnect any or all residential services remotely at will, limited only by policy constraints.

Current utility practice is to use service switches to reduce field labor associated with disconnecting and re-connecting seasonal or delinquent accounts. However, in the context of electric reliability, having a service switch at every location enables some entirely new applications. In the event of a distribution system outage (e.g., faulted feeder), operating service switches and solar PV could be used to facilitate micro-grids to limit the number of customers without service, reduce the duration of the outage to certain customers or enhance service to selected critical loads (e.g., fire, police, public safety).

Like many new applications enabled by Smart Grid, there are important and unresolved policy issues and system interconnection requirements (e.g., safety). Interconnection requirements are discussed later in this Report.

A summary of Smart Grid applications, which are potentially promising to Oregon's electric distribution reliability (resiliency), are noted below:

- Automated revenue meters that sense and report higher speed customer demand and energy, including voltage, outage times and durations, and meter tampering events.
- Customer-owned devices that communicate with the meter or other utility resources to capture and respond to operating conditions (e.g., thermostats, controllers for water heaters, pool pumps, air compressors).
- Customer-owned generation (e.g., bio-fuels) can be metered by AMI and supported by "smart" coordination and protection devices that protect both the host site and the surrounding grid from synchronization and backfeed hazards. This application provides an opportunity for micro-grids to function during emergency conditions and, thereby, provide electric reliability and resiliency improvements to critical customers (subject to adherence to interconnection standards).
- Switch monitoring and control electronics that sense local operating conditions and respond to commands based on conditions elsewhere in the grid.
- Faulted circuit indicators that detect and report large line current surges.
- Transformer monitors that detect and report temperature and oil contamination.
- Pole-top boxes with radios and computers that receive and store data, and process that data to determine immediate conditions and control needs.
- Small- and large-scale wind and solar supplies (metered by AMI) could communicate with utility resources to coordinate Oregon's grid operations. This application provides an opportunity for micro-grids to function during emergency conditions and, thereby, provide electric reliability and resiliency improvements to critical customers (subject to adherence to interconnection standards). Such resources might also add aid in grid support by adding a geographically distributed source of electricity that is not dependent on conventional resources.
- Other renewable or distributed generators, such as small hydro and local backup supply that similarly communicate and coordinate. These distributed sources will make it possible to operate micro-grids of the distribution system that may be cut off from central electric supply. As noted above, micro-grids may be useful during emergency conditions and provide electric reliability and resiliency improvements to critical customers (subject to adherence to interconnection standards). Such resources might also add aid in grid support by adding a geographically distributed source of electricity that is not dependent on conventional resources.

Outage Management

AMI is a significant enhancement to the utility's' ability to quickly assess and respond to service outages, and thereby affect reliability. AMI meters report the loss of power at its location to the utility. In the event of a challenge to the electric system that results in some outages, the utility will receive these messages and will know the scale and locations of the outage within minutes. Where remotely operable switches are installed, the utility will be able to redirect power flow and will track the progress of service restoration efforts.

Even without remote switch control or automation, service restoration is sharply improved because the dispatchers know much more about the problem they are addressing.

Sectionalizing Switches

Sectionalizing switches are not widespread, but are installed in many places. They allow the utility to isolate distribution problems to minimize the number of affected customers. Some such switches have communications that make them remotely operable, and this feature will expand quickly as AMI and other communication infrastructures are deployed. Automated and remotely operable sectionalizing switches will be a valuable tool for grid operators to use to isolate faulted distribution feeders, thereby reducing the number of customers without service and duration of outages.

Telephone interviews with IPC, PacifiCorp, PGE, and PUC staff revealed that there are no current plans in place to utilize sectionalizing switches to respond to energy emergencies. Instead, utilities intend to use such switches, when available, to turn on or off customers during conditions such as failure to make payments or customer relocations.[68]

Smart Grid's Role in Leveraging Renewable Resources and Distributed Generation

Many utilities already have agreements with large customers that have backup generation—such as data centers and hospitals—to allow the utility to use the customers' on-site backup generation during emergency conditions to fill service gaps. The amount of such generation is commonly a significant contribution to meeting the utility's requirement. Automating the process will expand the available capacity by allowing utilities to employ a much larger number of smaller capacity generators owned/operated by customers. As mentioned earlier for other new operating functions, automating dispatch of customer-owned generation will require resolution of major technical and policy issues.

Other renewable and distributed generators may be similarly controllable in the future by the utility using the sensing, communication, and automation of Smart Grid. Again, this will require resolution in advance of issues related to system protection, safety, and policy matters. This is especially relevant in Oregon, as few utilities have currently implemented Smart Grid applications. The status of Smart Grid applications in Oregon is discussed later in this Section.

[68] Telephone interview with PUC, PGE, IPC and PacifiCorp staff during March 2011.

Smart Grid's Role in Improving the Resiliency of Electric Infrastructure and Effectiveness of Renewable and Distributed Resources

A variety of Smart Grid technologies can be used in Oregon to improve the resiliency of its electric delivery infrastructure and support the deployment and penetration of renewable resources. Since the status of Smart Grid rollout at Oregon's three largest utilities is in its infancy, the focus of this discussion is on what Oregon's utilities *could* do and not on their actual progress.

Most Smart Grid technologies are broadly categorized or associated with a variety of Distribution Automation (DA) or AMI technologies. DA and AMI are broadly overlapping Smart Grid technologies that provide utilities a variety of applications and options for collecting data from the transmission and distribution systems and customers, monitoring operations, and controlling a variety of transmission and distribution functions.

DA includes a variety of technologies and applications that enable utilities to extend real or near real-time monitoring and control to a variety of electric transmission and distribution functions. Many utilities already have a communication infrastructure needed for remote monitoring and control of important transmission and distribution substation level equipment. This is traditionally referred to as supervisory control or "SCADA." Many utilities are expanding their supervisory communication networks or using the AMI communication infrastructure (see AMI below) to extend monitoring and control to other equipment and operating functions throughout the distribution network and, in some cases, to individual customers for direct load control. DA provides real or near real-time monitoring and control at substations, distribution line devices, switches, and sensors enabling utilities to operate the distribution system, relieve transmission and distribution loading during routine critical peaks, detect and isolate faulted or outaged line sections, and execute switching operations to avoid potential outages caused by overloading or under voltage conditions, or quicker service restoration if an outage occurs.

Many utilities outside of Oregon are implementing AMI as part of their Smart Grid projects. AMI is a technology that measures and collects energy usage from smart meters that are installed at customers' premises. A variety of AMI technologies and associated communication infrastructure are available from vendors. Most AMI systems have two-way communications enabling the utility to interact with smart meters, in-home displays, programmable thermostats, direct load control switches, and eventually appliances at customers' premises. This two-way communication enables automating and remotely performing a variety of routine tasks in lieu of dispatching field personnel. Examples include meter reading or performing a customer "turn-on/turn-off," both of which can be performed remotely with AMI. In addition, this two-way communication enables utilities to provide customers with price or other incentives that encourage lower energy usage during times with high energy prices or during periods of critical peak demand where system reliability may be lower. Data from customers' smart meters enables utilities to monitor power quality, voltage levels, near real-time kW demand (e.g., 15-minute intervals) at customers' premises. Near real-time demands for all customers may be aggregated by the utility's distribution automation models and applications to monitor loads and voltage levels throughout all levels of the transmission and distribution system.

Intelligent Routing

The intelligent routing of electricity may be facilitated by certain Smart Grid applications. Today, it is commonplace in Oregon's distribution systems (feeders) to be designed and operated in a manner that is normally radial. Electric energy is generally provided over a single path that emanates from the substation to the customer. Most feeders also contain switches that allow certain customers or segments of feeders to be transferred to a different feeder during outage conditions. This switching process is manual and causes customers to be "dropped" momentarily and then "picked up" by the second feeder. Traditionally, such operations are often limited since there is usually insufficient time to analyze whether the second feeder has the capacity to serve additional electric demand.

Smart Grid can augment the manual process that is in use in Oregon today with one that is high-speed and to some degree, automatic (Distribution Automation or DA). DA provides an automated response to feeder line faults by using an analytical assessment, direct automatic feeder sectionalizing, and restoration. After the system detects a line fault, it determines its location, and opens the nearest available switches (or fault interrupters) during a tripped state of the fault-clearing recloser or breaker. This automatically isolates or sectionalizes the faulted segment from the rest of the feeder. Afterward, the system automatically closes switches to restore power to unfaulted distribution feeder segments. This sequence of events is considered to be self-healing since it occurs automatically, thus providing a key benefit of a Smart Grid. The validation process, which confirms the faulted distribution feeder segment, is a critical step and must precede any automatic restoration.

DA and AMI functions are often interfaced with other utility applications and databases to provide utility personnel situational awareness of transmission and distribution operating conditions, outages, and contingencies for restoring electric service. These applications and databases include outage management systems (OMS), geographic information systems (GIS), engineering analysis or energy management systems, customer information systems, and other systems. All of these systems are in place to today, to varying degrees at IPC, PacifiCorp and PGE, as discussed later in this Report. Together, all of these technologies and applications can provide utilities situational awareness needed to maintain or restore electric service to important public services such as police, fire, and healthcare facilities or even customers on home life support. Specific examples of candidate approaches to the intelligent routing of electricity in Oregon are discussed below.

Load Management

A variety of load management strategies enable utilities to identify and prioritize electric service to important public facilities and reduce non-essential customer loads when available power generation, transmission, and distribution capacity is limited during critical peak periods, system emergencies or outage restoration contingencies. Load management strategies that encourage customers to reduce power use include critical peak pricing or demand response (DR), interruptible service tariffs, and direct load control programs. Several DA and AMI vendors offer applications enabling utilities to implement one or more of these load management strategies.

Service Switches

Service switches available "under the meter cover" on AMI meters are used by many utilities to perform a variety of routine service functions such as customer "turn-ons/turn-offs" in lieu of dispatching field personnel. In addition to the load management strategies presented above, these AMI service switches may be used to prioritize electric service to important public facilities and customers with home life support and temporarily interrupt service to non-essential customer loads when available power generation, transmission, and distribution capacity is limited during critical peak periods, system emergencies or outage restoration contingencies. Alternately, some AMI vendors offer service switches with a load limiting capability or breaker that limits how much power is available to an individual customer. (Service switches are typically only available in single-phase meters rated 200 Amp or less, which covers almost all residential and small commercial customers.)

A sample list of vendors that provide DA switching equipment include the following:[69]

- ABB
- Cooper Power Systems
- G&W Electric
- General Electric
- S&C Electric
- Schneider Electric
- Siemens Energy

DA, AMI and OMS

Situational awareness provides utilities with the near real-time awareness tools that are needed to develop outage restoration plans that include establishing priorities, contingencies, and options for restoring service to important public facilities and other customers. Similarly, utilities are required to have emergency load reduction plans in case of under-frequency caused by a sudden loss of generating units or other major transmission, or load curtailment related emergency. Many utilities have relays and controls that can automatically trip or disconnect individual distribution feeders or entire substations in case an under-frequency event occurs. For major transmission or load curtailment emergencies, utilities may use voltage reduction to lower peak demand, publicize through the media urgent appeals for conservation to customers to reduce power use, and in extreme cases resort to rolling blackouts. Utilities with DA,

[69] R. W. Beck does not recommend or endorse any particular AMI or Smart Grid related vendors, hardware or equipment. All statements pertaining to a specific vendor, hardware or equipment are for illustrative purposes only.

AMI, and other utility applications previously mentioned can refine their emergency load curtailment plans to avoid interrupting electric service to important public facilities.

Emergency Service Providers

Many important public services such as fire and healthcare facilities already have diesel powered standby electric generators on-site in case normal electric service is interrupted. The ability of these facilities to continue operations depends on the capacity of the on-site generators and the available fuel supply. Use of diesel powered standby generators may be supplemented with renewable resources such as wind and bio-fuels to provide additional capacity and/or extend the diesel fuel supply. This enables important public facilities equipped with diesel standby generation and renewable resources to maintain normal or near normal operations for longer periods in case of a serious or extended power outage.

Prioritization of Service

During an emergency condition, Oregon’s electric utilities could utilize the previously noted Smart Grid applications to accomplish the intelligent routing of electricity to serve customers in a prioritized manner. Priorities are discussed in Section 2 of this Report.

The status of Smart Grid related applications at key Oregon utilities is summarized below.

Central Lincoln People’s Utility District[70]

CLP obtained approximately $9.9 million in ARRA funding to supplement its two-way communications between the utility and all of its 38,000 customers through a Smart Grid network and other in-home energy management tools. The project will deploy Smart Grid communication and control technology to optimize distribution system reliability and efficiency, restore energy quickly following outages, and empower consumers to reduce their energy usage.

While CLP is not one of Oregon’s largest electric utilities, it may be one of its most advanced utilities in terms of Smart Grid implementation.

Eugene Water & Electric Board[71]

Eugene Water & Electric Board (EWEB) is examining the costs, benefits, and applications of numerous candidate Smart Grid applications. While AMI, Automated Meter Reading (AMR) and other Smart Grid applications have not been implemented, this may change in the future. EWEB’s analysis is on-going.

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[70] http://www.smartgrid.gov/project/central-lincoln-peoples-utility-district-smart-grid-project
[71] Telephone interviews with EWEB staff during 2010-2011.

Idaho Power Company[72]

Approximately 90 percent of IPC's Oregon customers are metered by AMI. The decision regarding which of its Oregon customers will receive AMI is based on a cost/benefit calculation. To date, its most significant cost factor in IPC's Oregon analysis has been spreading the fixed costs that are required for AMI communications over a relatively small number of customers. IPC's Oregon customers are generally located in rural areas where customer density (e.g., number of customers served by any given substation, feeder or per square mile) is relatively low. IPC perceives the key benefits as being based on a reduction in the number of required meter readers, vehicle requirements and accidents, fuel costs, number of meters that require re-reading, environmental impact, customer impacts associated with being on premises, and future rate flexibility. IPC is offering some of its large industrial and commercial customers in Oregon time of use rates, which is facilitated by AMI.

IPC's Smart Grid analysis did not include reliability, grid resiliency or integrating renewable resources. IPC's AMI meters in Oregon do not include a service switch. This omission precludes the capability to broadly curtail service to relatively low priority customers during an electric supply emergency. The decision to omit service switches was based on the cost of the switch.

IPC has not implemented any other Smart Grid functions in Oregon (e.g., outage management, sectionalizing switches, load management, intelligent routing, service switches, distribution automation).

IPC's current AMI/Smart Grid strategy in Oregon focuses on meter reading and does not enhance electric resiliency.

PacifiCorp[73] [74]

PacifiCorp staff verbally reported that they have not been able to quantify the economic value of AMR, AMI or Smart Grid. Their internal cost/benefit calculations find that AMI would be economical only if there was a very high degree of customer participation in alternative rates, such as time of use rates, and associated peak load reduction. They perceive the potential benefits of Smart Grid as being DR (e.g., reduction in peak demand) and improvements in reliability. PacifiCorp is concerned about customer's perceptions that AMI creates "outside" control. PacifiCorp also noted that, as its mission is to be a low cost provider of safe and reliable electricity, AMI or Smart Grid would artificially increase the cost of electricity. An additional concern is whether the PUC would approve PacifiCorp's AMI/Smart Grid related costs in rate base.

PacifiCorp has completed a limited launch of AMI in areas of high risk and high growth outside of Oregon.

[72] Telephone interview with IPC staff on March 11, 2011.
[73] Telephone interview with PacifiCorp staff on March 8, 2011.
[74] "Integrated Resource Plan", PacifiCorp, March 31, 2011, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf

PacifiCorp is actively watching the successes and failures at other utilities.

PGE[75,76]

PGE completed its installation of a system-wide wireless AMI project that consists of 827,000 end points. The project will reportedly produce operational savings of $18.2 million per year. PGE's AMI system is a two-way wireless fixed network and uses 46 collectors. By September 1, 2010, PGE installed nearly 700,000 AMI meters and was successfully capturing nearly 100 percent of the required daily billing reads. PGE scaled up the company's Meter Data Management System (MDMS) to handle register reads from 1.2 million meters, interval data from 100,000 meters, and storage for up to seven terabytes of validated meter data.

PGE's Integrated Resource Plan (IRP) states that it intends to accelerate its Smart Grid efforts. Such efforts would be funded through a grant from the U.S. DOE in the amount of $76.2 million (under the Smart Grid Investment Grant program) to help support its existing AMI deployment and a new Smart Grid initiative that would result in significant modernization and automation of its distribution and delivery systems over the next 5-10 years, including:

- Sense and Respond: Real-time data processing architecture.
- Secure Energy Network: Cyber security for critical transmission and distribution assets.
- Distribution Technology Upgrade: Enable usage of interval data for Smart Grid functions.

PGE 's IRP states that these projects will enable outage and voltage events, which are monitored at the meter, to be communicated to its Repair Dispatchers, demand and energy usage information to be shared with customers via two-way communications, and provide for a secure communication network to send price and control information. The IRP further indicates this future program would help prevent outages from distribution equipment failure from occurring, increase customers' understanding of their energy usage, facilitate DR programs, improve outage response capabilities and increase the overall reliability and cost effectiveness of its distribution system.

If implemented, such programs may enhance PGE's electric resiliency.

Future Challenges to Smart Grid Development

The above referenced discussions with Oregon's key utilities brought to light a number of challenges that utilities face in considering the implementation of future Smart Grid applications. These challenges are briefly noted below.

- **Economic Justification:** Some of Oregon's utilities have been unable to demonstrate that Smart Grid is economically justified, as shown by their individual

[75] http://tdworld.com/smart_grid_automation/pge-ami-award-0910
[76] "2009 Integrated Resource Plan," PGE, November 5, 2009

cost/benefit evaluations. Economic justification is perceived to be a necessary step in obtaining an approval for implementation from each utility's management.

- **Rate Base Uncertainty:** Utilities perceive that economic justification is a necessary step in obtaining the PUC's approval for rate base inclusion. Utilities verbally reported that such uncertainty causes them to be reluctant to make investments in Smart Grid. In contrast, PUC staff verbally reported that the PUC has openly stated that it welcomes AMI proposals.
- **Risk Aversion to Adopt New Technologies:** Smart Grid technologies are evolving and new applications are expected in the future. Concern about stranded investments are an important concern.
- **Cyber Security:** Smart Grid technologies provide potential access to customer and utility information systems and operations. Oregon's utilities are responding to this threat by implementing the appropriate safeguards. Cyber threats are expected to change over time, requiring utilities to monitor this issue on an on-going basis and periodically review and update their firewalls and related practices.

Quantifying Electric Reliability and Resiliency

In the context of EAP, the terms "reliability" and "resiliency" may be used interchangeably and serve as measures for the quality of electric service that is received by utility customers. To avoid potential misrepresentations in the meaning of such terms, the IEEE has developed a standard that provides guidance to measuring and quantifying electric reliability.[77] The adoption of that standard is voluntary by electric utilities, though its usage appears to be generally widespread throughout the industry. That standard is used throughout this Report and is founded upon the measurement of historical outage data (including the number of customers without service, the duration of electrical outages, and the number of events that affect each customer) to formulate a set of reliability indices.

Three commonly used indices are the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Interruption Frequency (MAIFI), which are defined below.

- **SAIDI:** The average duration of interruptions. SAIDI is measured as the number of minutes of outage time that an average customer would experience in any given year and is expressed mathematically as:[78]

$$SAIDI = \frac{Sum\ of\ customer\ interruption\ durations}{Total\ number\ of\ customers}$$

[77] "Guide for Electric Power Distribution Reliability Indices, Standard 1366-2003," IEEE, dated May 14, 2004.
[78] Ibid.

$$SAIDI = \frac{\sum_s r_i Ni_s}{\sum_t N_t} hours/customer\ year$$

- **SAIFI:** The average number of interruptions. SAIFI is measured as the number of interruptions that an average customer would experience in a given year and is expressed mathematically as:[79]

$$SAIFI = \frac{Total\ number\ of\ customers\ interrupted}{Total\ number\ of\ customers\ served}$$

$$SAIFI = \frac{\sum_i N_i}{\sum_t N_t}\ as\ interruptions/customer$$

- **MAIFI:** The average number of momentary interruptions. MAIFI is measured as the number of momentary interruptions that an average customer would experience in a given year and is expressed mathematically as:[80]

$$MAIFI = \frac{Total\ number\ of\ customers\ momentary\ interruptions}{Total\ number\ of\ customers\ served}$$

$$MAIFI = \frac{\sum_i IMNm_i}{\sum_t N_t}\ as\ momentary\ interruptions/customer\ year$$

For SAIDI, SAIFI, and MAIFI a lower index indicates better reliability.

Electric Resiliency in Oregon

An examination of Oregon's existing electric reliability is important to energy assurance planning. Problems that exist today provide guidance to areas of vulnerability, which may become critical during future electric emergencies. Existing reports from the PUC and NERC provide such insight into the reliability of Oregon's electric grid. Information from these reports is summarized below to provide an understanding of existing issues and areas of concern for the EAP.

PUC Reliability Evaluation

The PUC enacted Order Number 97-196 to direct investor owned utilities to annually collect and report on the reliability of their Oregon systems through the SAIDI, SAIFI, and MAIFI reliability indices. As noted above, issues that confront the reliable supply of electricity are important to Oregon's EAP as they suggest areas of potential vulnerability during emergency conditions. During the 2003-2009 time-frame, data

[79] Ibid.
[80] Ibid.

for the IPC, PacifiCorp and PGE suggest the following (assuming the exclusion of momentary events):[81]

- The frequency of outages (SAIFI) has been generally constant for PacifiCorp and PGE during the 2003-2009 time-frame. PacifiCorp and PGE customers experienced approximately one outage during 2009.
- IPC has experienced general improvement in the frequency of outages. IPC customers experienced approximately 1.8 outages during 2009.
- The duration of outages (SAIDI) has been generally constant for IPC and PGE during the 2003-2009 time-frame, lasting approximately two minutes during 2009.
- The duration of outages at IPC has been comparatively more erratic. Outages lasted approximately 3.6 minutes during 2009.

There has been improvement in the number of momentary outages experienced by customers at IPC, PacifiCorp, and PGE during the 2003-2009 time-frame. This finding may be affected by a change in the way that the IEEE defined "momentary" in the creation of its most recent standard.

The NERC enacted a voluminous set of standards, which address the reliability (resiliency), security, and operations of electric generation, transmission, communications, and protective systems in the United States.[82] One aspect of such standards is the CIP program, which coordinates all of NERC's efforts to improve physical and cyber security for the bulk power system as it relates to reliability. While a review of the entire set of NERC standards is outside of the scope of this Report, it is useful to examine the compliance of electric utilities in Oregon to gain some insight into their electric resiliency. Pertinent findings of such review include:

- In April 2008, PacifiCorp received notice of a preliminary non-public investigation from the FERC and NERC to determine whether an outage that occurred in its transmission system in February 2008 involved a violation of reliability standards.[83]
- On July 20, 2009, Lane Electric Cooperative (LEC) self-reported to the NERC its failure to include high-side substation transformer protection systems at its Hideaway and Oakridge Substations. In addition, LEC could not provide documentation for all of its protection system devices and related maintenance and testing.[84]
- On August 20, 2008, Umatilla Electric Cooperative Association (UMEC) self-reported that it failed to include the high side protection systems at its Coyote Springs, Chemical, Feedville, Hermiston Butte, Juniper Canyon, Power City,

[81] "Oregon Investor-Owned Utilities, Seven-Year Electric Service Reliability Statistic Summary, 2003-2009," Oregon Public Utilities Commission, October 2010.
[82] "Reliability Standards for the Bulk Electric Systems in North America," NERC, June 1, 2010.
[83] "Form 10-Q, Quarterly Report" to the U.S. Securities and Exchange Commission, PacifiCorp, November 5, 2010.
[84] "NERC Abbreviated Notice of Penalty Regarding Lane Electric Corporative Inc./PNGC, FERC Docket No. NP11," dated December 22, 2010.

Sandpoint, Umatilla, and Westland Substations in its maintenance and testing program.[85]

- On July 20, 2009, Coos-Curry Electric Cooperative self-reported to the NERC its failure to include the high-side substation transformer protection systems at the Morrison, Sumner, and Geisel Monument Substations.[86]
- On July 23, 2009, EWEB self-reported to the NERC that it failed to perform required sufficient stability studies.[87]
- On January 9, 2008, EWEB self-reported to the NERC that it did not provide documentation of its protective system maintenance and testing program.[88]
- On October 8, 2008, Salem Electric self-reported to the NERC that it failed to include the high-side substation transformer protection systems at the Hughes, Alumina, and Read Substations.[89]

The above NERC violations demonstrate reliability problems in Oregon. These violations provide specific guidance to issues that need to be addressed in order to provide the state's constituents with reliable electric service, with and even without the occurrence of an electric emergency.

A research of public documents did not reveal any other violations or penalties, during the past few years, from state or federal agencies that pertain to the resiliency of Oregon's electric utilities.

Impact of Renewable Resources on Electric Resiliency

Impacts of Renewable and Distributed Generation

Oregon's electric distribution feeders provide service in only one direction, from the substation (source) to the customer (load). This characteristic may cause all "downstream" customers to be adversely affected whenever an event occurs in the "upstream" network. Oregon's utilities have taken a proactive stance in customer reliability by implementing a distribution feeder protection strategy that is based on the operation of certain devices (e.g., fuses, relays, and breakers) to sectionalize effected equipment. The underlying objectives of the strategy are to safeguard public and employee safety, selectively operate protective devices, protect capital investments (e.g., minimize or eliminate the exposure of equipment such as transformers, conductors, or cable to the fault), rapidly minimize the number of

[85] "NERC Abbreviated Notice of Penalty Regarding Umatilla Electric Cooperative Association, FERC Docket No. NP10," dated December 22, 2010.
[86] "NERC Abbreviated Notice of Penalty Regarding Coos-Curry Electric Cooperative Association, FERC Docket No. NP10," dated December 22, 2010.
[87] "NERC Abbreviated Notice of Penalty Regarding Eugene Water and Electric Board, FERC Docket No. NP10," dated November 30, 2010.
[88] "NERC Abbreviated Notice of Penalty Regarding Eugene Water and Electric Board, FERC Docket No. NP10," dated December 30, 2009.
[89] "NERC Abbreviated Notice of Penalty Regarding Salem Electric, FERC Docket No. NP11," dated November 5, 2010.

customers without electric service, and minimize the duration of such outages. This general approach has been in practice for many years in Oregon. Since the number of protective devices on any given feeder has been historically limited by economic considerations, the strategy often results in the curtailment of service to customers that are served by unaffected equipment.

It is fundamental to note that such mono-directional models of thought predate the advent of distributed generators, which can result in multi-directional flows on distribution feeders. Multi-directional approaches can theoretically backfeed portions of a distribution feeder during an outage-related event and facilitate continuity of service to a larger number of customers. This alternative approach could result in improvements in electric reliability and associated indices, SAIDI (by reducing the number of customers without service) and SAIFI (by reducing the frequency that customers are without service).

In practice, this approach is confronted by a number of critical factors, which are briefly listed below and discussed in greater detail later in this Report.

- Safety: Public and utility employees need to be protected from exposure to energized downstream or micro-grid circuits.
- Adequate supply: The real-time capacity and energy of distributed generators may not be sufficient to adequately serve the micro-grid.
- Location of renewable and distributed generators: Unaffected feeder segments may not contain sufficient on-line distributed generator capacity (e.g., capacity factor and capacity value).
- Smart Grid applications: Communications and control of renewable and distributed generators between their owners and the utility is of paramount importance during an outage event.
- Energy storage: Capacity and energy from renewable and distributed generators are often intermittent and require storage (e.g., batteries).
- System control: Renewable and distributed generators are not generally capable of providing adequate voltage and frequency support.
- Standards: Adherence to generally accepted standards is a necessary step in accomplishing the above objectives.

Improving Oregon’s electric system resiliency through renewable energy resources and Smart Grid is not without its costs. Alternatively, benefits to electric reliability are also available. The following discussions present the findings from two separate case studies where improvements in electric reliability have been simulated.

Case Study: Renewable and Distributed Generation Impact Simulations in Colorado, Virginia, and California

One recent study examined the direct impact that renewable and distributed generators can have on electric reliability, including simulated estimates of improvements in outage durations (SAIDI) and frequency (SAIFI).[90] That research examined customer reliability under the following variable conditions:

- Population size: The number of connected distribution residential customers was 10, 100, and 1,000 meters (no commercial or industrial customers).
- Solar PV penetration: Reliability was tested at solar PV penetration rates of 10 percent, 30 percent, and 50 percent.
- Solar PV capacity: The capacity of the individual renewable or distributed generators was assumed to be 2.1 kW.
- Energy storage: Reliability was simulated with and without a 1-kWh battery at each solar PV location.
- Geographic locations: The study used communities located in Golden - Colorado, Sterling - Virginia, and Hanford - California.

Since this study is founded on mathematical simulations instead of field measurements, certain critical assumptions were required. First, in each test location, outages were assumed to follow local historical patterns (e.g., seasonal and time of day) that were observed in practice. Second, it was assumed that the 1- kWh battery was fully charged and operational when called upon to operate. There were no failure rates applied to the distributed generator, battery or interconnection (e.g., Smart Grid, communications, controls). Next, the location of customers with solar PV was uniformly distributed along the distribution feeder. Benefits that might be attributed to location are unavailable. Lastly, and perhaps most importantly, the utilization of the solar PV and battery backup were unencumbered by capacity values, safety, operational, standards or policy issues.

Some of the key observations of that study are included below:

- Improvements in SAIDI were observed in all three communities, especially in Golden, Colorado. The study did not explain any uniqueness that may be attributed to Golden, Colorado. In Golden, Colorado alone, solar PV penetration rates of 10 percent and no battery backup resulted in a reduction of SAIDI of approximately 20 percent. Increasing solar PV penetration to 30 percent and 50 percent resulted in SAIDI improvements of approximately 30 percent and 40 percent, respectively.[91]
- Improvements in SAIFI were observed in all three communities. Again, this finding was especially pronounced in Golden, Colorado. The Golden, Colorado test case of 10 percent solar PV penetration and no battery backup resulted in a reduction of SAIFI of approximately 10 percent. Increasing solar PV penetrations rates to 30 percent and 50 percent resulted in SAIFI improvements of approximately 25 percent and 30 percent, respectively.[92]

[90] "Enhanced Reliability of Photovoltaic Systems with Energy Storage and Controls," National Renewable Energy Laboratory, February 2008.
[91] Ibid.
[92] Ibid.

- Adding a 1-kWh battery at each solar PV location resulted in enhanced improvements in outage duration (SAIDI). The simulated reduction in SAIDI in Golden, Colorado for distributed generation penetration rates of 10 percent, 20 percent, and 50 percent were approximately 50 percent, 75 percent, and 75 percent, respectively.[93]
- Adding a 1-kWh battery at each solar PV location resulted in enhanced improvements in outage frequency (SAIFI). The simulated reduction in SAIFI in Golden, Colorado for solar PV penetration rates of 10 percent, 20 percent, and 50 percent were approximately 50 percent, 40 percent, and 35 percent, respectively.[94]

Case Study: Renewable and Distributed Generation Impact Simulations in Blacksburg, Virginia

A second study also quantified the impact that renewable or distributed generation might have on electric reliability by examining distribution feeders that serve specific residential communities in Blacksburg, Virginia.[95] Like the preceding study, this examination was also based on simulation models and not field measurements. However, unlike the previous work, this study focused on the effects of applying a single generator at different locations along the feeder and omitted any SAIFI analysis. Additional assumptions include:

- Distribution disconnects, transformers and fuses were 100 percent available.
- Failure rate for the distributed generator was 10 percent.
- Failure rate for main sections of distribution feeders was 0.1 failure per kilometer (km) per year.
- Failure rate for distribution laterals was 0.2 failures per kilometer (km) per year.
- Total isolation and switching time is two minutes for distributed generators.
- Repair time for each section is four hours while that for each distributor lateral is two hours.
- Renewable and distributed generators were installed at assumed, defined points along the distribution feeder to be used as a backup resource.
- The capacity of the distributed generator was assumed to be 150 kW, 300 kW or 500 kW. The peak demand on the circuit was assumed to be approximately 1.7 MW.

This study found that the reduction in SAIDI was proportional to the size of the renewable or distributed generator and its distance from the substation (source). Moving the distributed generator further from the substation (closer to the end of the feeder) resulted in increasingly improved SAIDI.

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[93] Ibid.
[94] Ibid.
[95] "Reliability Benefits of Distributed Generation as a Backup Source," Waseem, Pipattanasomporn and Rahman, IEEE PES 2008.

As shown in the following table, the base SAIDI value was 0.7134 hours per year. Placing a 150-kW generator at approximately the mid-point of the feeder resulted in a new SAIDI of 0.6890 hours per year, an improvement of 3.4 percent. Moving the generator to the end of the circuit reduced SAIDI even further, to 0.6594 hours per year, an improvement of 7.6 percent. Further improvements in SAIDI were obtained by increasing distributed generator capacity. A 300-kW unit located at the circuit's mid-point and end-point resulted in SAIDI values of 0.6711 hours/year and 0.6189 hours/year, which correspond to improvements of 5.9 percent and 13.2 percent, respectively.

Table 4-1[96]
System Average Interruption Duration Index (SAIDI)

DG Location	Distance (mile)	Distributed Generator Capacity		
		150 kW	300 kW	500 kW
A	0.0	0.7134	0.7134	0.7134
B	0.5	0.6573	0.6298	0.6138
C	0.8	0.6890	0.6711	0.6168
D	1.2	0.6668	0.6308	0.5693
E	1.7	0.6594	0.6189	0.5515

Figure 4-1, below, depicts the results of plotting the authors' resultant SAIDI data against the generator's distance from the substation. It should be noted that the results are not monotonically decreasing, an observation that the authors fail to explain.

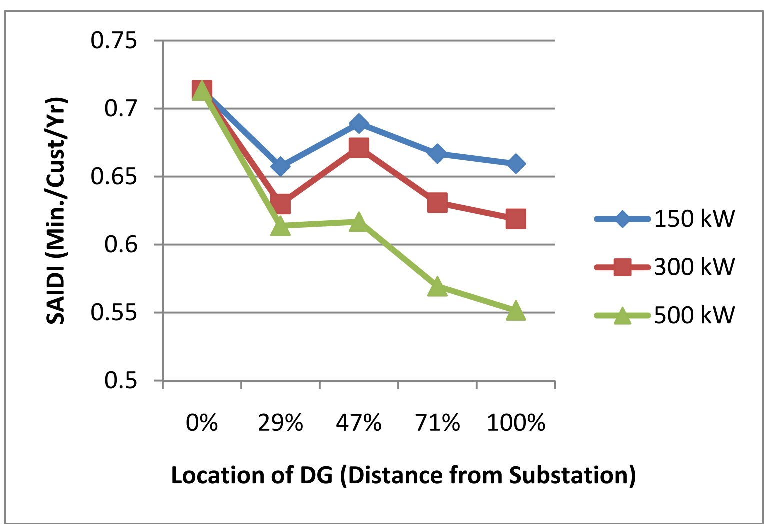

Figure 4-1: Reliability versus the Size and Location of a Renewable or Distributed Generator

The next step is to translate the preceding raw data into a percentage improvement in SAIDI for different generator sizes and distances from the substation. Figure 4-2, below, captures such data and clearly shows the effect that generator size and location

[96] Ibid.

have on SAIDI. Under the assumptions and models presented in this study, the best available condition results in a reduction in SAIDI of approximately 23 percent by locating a 500-kW generator at the end of the feeder, which represents approximately 30 percent of total feeder demand.

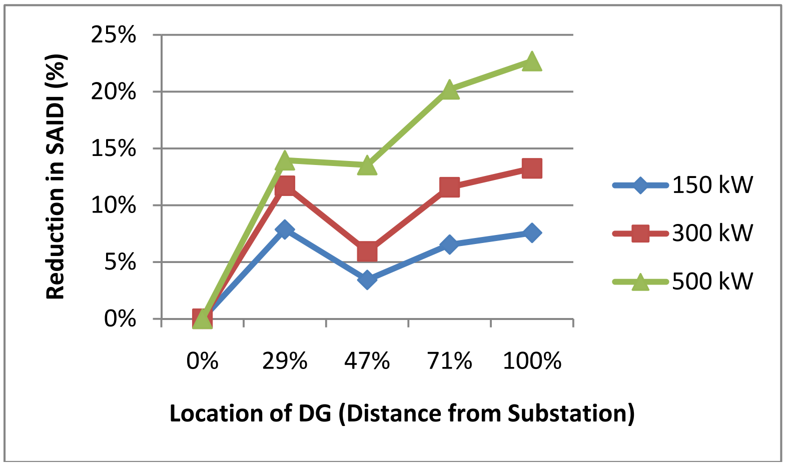

Figure 4-2: Reduction in SAIDI versus the Size and Location of a Renewable or Distributed Generator

System Protection Requirements for Renewable and Distributed Resources

One of the key challenges that confront the application of renewable resources and distributed generators in Oregon's EAP is their safe and prudent integration into the overall electric grid. Standards are in place today to guide that process and new standards are anticipated in the future. One motivation for developing new standards is found in the rollout of Smart Grid applications, which hold considerable promise and challenge to system operators in coping with electric emergencies.

Additional information on system integration is found in Appendix C.

Adding renewable or distributed generators requires the adherence to adequate power system protection measures to ensure the safe operation of the generator, remaining power system, utility staff, and the general public. Protection is intended to minimize the impact of unavoidable faults in the system that could cause over-currents or over-voltages. To illustrate such conditions, the following hypothetical scenarios should be considered:

- A synchronous coupling of networks would result in high currents.
- Earth faults can cause high stray voltages and endanger people, livestock, and wildlife.
- Operating renewable and distributed generators when the remaining distribution system is off-line could endanger line crews.
- Non-utility contractors or owners may be responsible for the planning, design, and construction of renewable or distributed generators, thereby raising questions about safety.

The generally accepted practices that apply to the design and coordination of protective systems for distribution systems as well as the renewable or distributed generator include:

- Selectivity: The protection system should isolate and de-energize only the faulted segment (or the smallest possible portion) of the system in order to minimize associated consequences.
- Redundancy: Protection systems generally contain multiple devices and strategies that are functionally redundant, yielding improved reliability and backup protection.
- Security: In addition to responding to abnormal events, protection systems also need to reject transient events that are not faults.
- Dependability: Protection systems need to be dependable and exhibit an extremely high degree of reliability.

One additional area of concern is that renewable and distributed generators should cause utilities to re-evaluate existing protective strategies and devices. Renewable and distributed generators pose the potential to affect the available fault current on the distribution feeder, thereby requiring a revised investigation into the existing protection scheme. Moreover, the schedule for implementing new generators is outside of the utility's control, which will drive the frequency for such re-evaluations. The overarching concern here is that some utilities may not be well suited to conducting protection re-evaluations in a timely manner.

System Upgrades for Renewable and Distributed Generation Integration in Oregon

This Report identifies conditions where the implementation of renewable and distributed generators could have a beneficial effect on utility systems, especially at the distribution level. Prescribed operational and planning attributes are intended to serve as a roadmap for utilities and generators to function more seamlessly to achieve improvements in electric resiliency. Roadmap ingredients include:

Operations

- System operators will need to communicate with generator owners whenever work is being conducted on local feeders.
- System operators need the means and the authority to control renewable or distributed generators, especially in times of system disturbances or maintenance.
- Safety practices will need to be reviewed and modified, especially grounding practices.
- Field crews may require training to address new safety issues.

The utility response to such issues is to consider upgrades such as:

- Communications between utility operations centers, renewable and distributed generation owners.
- Switch additions.
- High-speed generation switching control at utility operations centers.
- New or additional training programs need to be implemented.

Planning and System Protection

- Distribution planners will need to conduct power flow studies to identify distribution system planning violations that are associated with the addition of renewable and distributed generators (e.g., identify overloaded conductors and transformers, voltage violations). Each such violation will require a case-by-case analysis of problems, candidate solutions, a preferred solution, and cost analysis. This is especially important in cases where generator capacity exceeds customer demand.
- Transmission planners will need to review existing capital construction plans to confirm compliance with planning criteria and planned projects given alternative generation and demand scenarios.
- Conduct short circuit studies to identify fault current duties and compare to breaker duty ratings.
- Conduct fuse coordination studies that account for backfeed conditions.
- Utilities will need to review their resource plans to ensure that future demand and generation forecasts are consistent with assumed adoption rates for renewable and distributed generators.

The utility response to such issues is to consider upgrades such as:

- Conductor replacement (response to overloads)
- Transformer replacement (response to overloads)
- Capacitor or inductor additions (voltage control)
- Switch installations (generator control)
- Communications (generator status)
- Inductor additions
- Breaker replacement
- Relay replacement
- Fuse replacement
- Review and revise fuel contracts

Some of the above upgrades could be accomplished by Smart Grid applications and that case-by-case analysis is required.

Options for Integrating Renewable Resources into Existing Grids

The following discussion presents options to promote the integration of renewable resources into Oregon's existing electric grid. Specific areas noted here include:

- Tariff regulation
- Uniform integration standards and policies
- Access to electric markets
- Rate base uncertainty
- Revenue incentives

Tariff Regulation

Oregon utilities have implemented net metering policies and tariffs filed with the PUC in compliance with Oregon Administrative Rules (OAR) 860-039. In addition the investor owned utilities have also filed tariff applications with the PUC, under OAR 860-083, necessary to implement the Volumetric Incentive Rate Pilot Program for Solar Photovoltaic Energy Systems, which filing was in compliance with Order No. 10-198. The small solar pilot program was mandated by legislation under Oregon Revised Statutes (ORS) 757.365. In regards to the development of renewable energy power sources such as wind and bio-fuels, Oregon's regulated utilities must comply with ORS 469A.065, which mandates each operator to meet the requirements applicable to the renewable portfolio standards under OAR 860-083. The regulatory commissions in certain states, which Oregon is one of them, have directed the regulated utilities to develop an IRP that specifies a timeline for introducing renewable wholesale power sources as part of their generation portfolio and feed-in tariffs to guarantee access to the transmission system.

In addition, some jurisdictions also encourage utilities to develop net metering policies and tariffs, such as Oregon's net metering rules, for customer-owned renewable energy power sources. Under a utility's net metering policies and tariffs, a customer receives a credit for the portion of generated energy that flows onto a utility's distribution system. Renewable resources may supply a portion or all of a customer's electricity requirements, depending on the resource's availability, capacity factor and capacity value, and electric storage capacity. An additional factor is the customer's ability and willingness to reduce electric usage during normal and peak demand conditions and unplanned outages (e.g., curtailments in available generation, transmission or distribution).

Net metering policies and tariffs establish the prices, terms, and conditions governing utilities' purchase of excess power produced by customer-owned renewable power sources. In addition, the utility's AMI system can provide near real-time data (e.g., 15-minute intervals) on the energy and demand being requested from customer owned renewable power sources.

Uniform Integration Standard and Policies

As stated above, Oregon has enacted ORS 469A.065, which mandates each operator to meet the requirements applicable to the renewable portfolio standards under OAR 860-083, and has promulgated rules, under OAR 860-082, which provides uniform technical, procedures, and agreements, that facilitate expedited, low-cost and straight forward interconnection policies for renewable resources. Oregon is one of the leaders in the U.S. in Wind and Solar energy generation development. As of 2010, Oregon had 2,600 MW of interconnected wind generators, with a total projection for 6,000 MW by 2020.

Rate Base Uncertainty

Conversations with utilities across the country indicate that there is some uncertainty in whether costs associated with AMI, Smart Grid or distribution automation will be approved for inclusion in utility rate base. Recent cases in Maryland and Colorado highly publicize this dilemma and send a cautionary note to utilities across the country.

Conclusions

Smart Grid, renewable and distributed generation pose a number of important benefits and costs to Oregon's EAP. The most notable benefits and costs are summarized below.

Benefits

- Improve electric reliability (as measured by a reduction in SAIDI and SAIFI).
- Reduce reliability-related penalties paid by utilities.
- Improve adherence to state renewable energy standards (if credit for pertinent distributed generators is attributed to the utility).
- Provide ancillary services, which are required to provide adequate grid resiliency.
- Reduce peak electric demand, which would cause an increase in spinning reserves, especially at times of greatest stress on the grid. An increase in spinning reserves is beneficial to grid resiliency as it allows utilities to have more standby capacity. .
- Reduce system losses and associated financial benefits to utilities and consumers. A reduction in system losses increases spinning reserves, as noted above.

Costs

- The practical value of a renewable or distributed generator is affected by its capacity factor (average annual electric production as a percent of maximum capacity) and capacity value (electric output as a percent of maximum capacity during peak demand conditions). One study notes that the capacity value for solar PV and wind resources range from 15 percent to 35 percent.[97] During an electric

[97] "Western Wind and Solar Integration Study," National Renewable Energy Laboratory, May 2010.

emergency, utilities can only rely on a fraction of the renewable generator's installed capacity. To illustrate, if the grid required 100 MW of capacity to maintain adequate reliability, approximately 300 MW of renewable capacity would need to be installed. The cost of such excess construction is a burden to electric rate payers.

- Appendix C outlines numerous requirements for the integration of renewable and distributed generators into the grid. Accomplishing such requirements is financially costly and has an adverse affect on electric rate payers.
- Protection systems must be examined on a case-by-case basis to identify necessary modifications.
- Transmission and distribution systems must be examined on a case-by-case basis to identify necessary capital projects that are associated with grid integration.
- Utility operators will need communications and operational controls.
- Field crews will need additional training, especially to address safety-related issues.
- Each renewable and distributed generator has its own capital, operating, maintenance, and fuel expense.
- Potential damage to neighboring electric customers due to renewable and distributed generators' power quality issues.

Section 5
FUTURE RENEWABLE ENERGY REQUIREMENTS

Introduction

Today, Oregon has a limited amount of renewable resources online. Renewable resources (excluding hydropower) during the past three years accounted for approximately two percent of Oregon's annual electricity requirements.[98] In the next 15 years, this figure is expected to change significantly. Oregon law requires that the two investor-owned utilities, PGE and PacifiCorp must supply 25 percent of their electric load with renewable resources. Under this law, the Renewable Portfolio Standard, Oregon's utilities will take significant steps forward in adopting and integrating renewable resources.

This Section provides insight into the challenges of such integration by addressing the following objectives:

1. Develop a framework for Oregon to ensure that future renewable development accommodates energy resiliency plans.
2. Develop a technology roadmap for enhancing the effectiveness of distributed renewable resources, through Smart Grid and other technologies, to provide energy during grid collapse.

Framework for the Inclusion of EAP

Renewable resources play an important role in promoting and facilitating energy resiliency in Oregon. However, obstacles also exist. A successful and sustainable framework must capture available benefits while confronting and resolving, to the greatest extent possible, relevant obstacles. The following ingredients are designed to be included in or addressed by Oregon's framework for future renewable development from the perspective of accommodating energy resiliency plans.

Fuel Diversification

Section 1 explores Oregon's dependence on hydroelectric resources and finds that the state is highly dependent on this singular resource for electric supply. While its exploitation allows Oregon to enjoy comparatively low electric rates, it has also inadvertently placed the state at risk of not being able to meet future customer demand. Figure 5-1 below, depicts considerable variation in annual precipitation. Periods of extended below-normal precipitation may leave Oregon's hydropower operators unable to provide reliable electric supply during prolonged drought conditions.

[98] ODOE, March 2011.

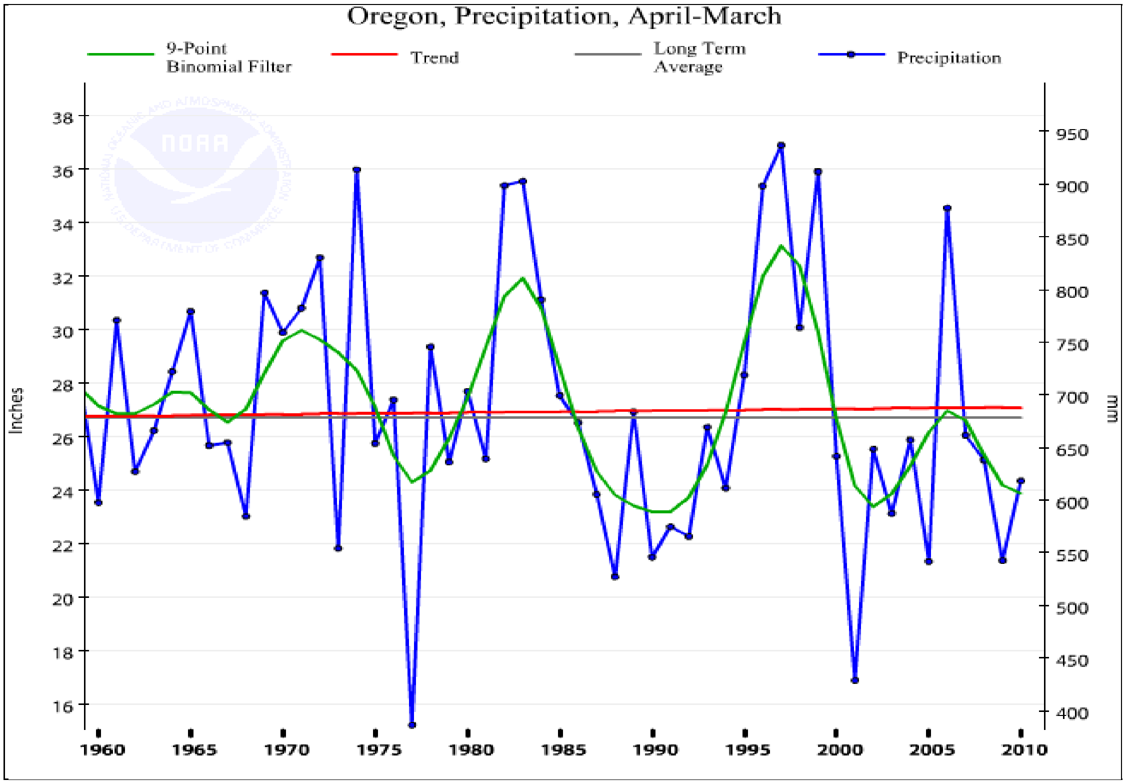

Figure 5-1: Historical Precipitation in Oregon

From the perspective of energy resiliency, a well diversified statewide energy portfolio reduces supply-side risks. Increasing the diversity of Oregon's resource mix reduces the exposure to problems that could arise from an over reliance on any individual fuel.

However, it is generally understood that changes to the state's resource mix would come at a cost. Balancing the need for energy resiliency with cost effective supply leads the debate to search for ways to incentivize energy developers to focus on non-hydroelectric alternatives.

The response from affected electric utilities is mixed. Utilities are expected to achieve the requirements laid out in the RPS. Nevertheless, they are not expected to "value" renewable resources to the same extent that they look to conventional resources. BPA and PacifiCorp stated that they consider renewable resources to be relatively unreliable (e.g., significantly lower capacity factors and capacity values), are considered to be non-dispatchable, and will not be initially utilized during emergency blackstart conditions.[99]

Geographic Diversity

The geographical diversity of electric resources can play a significant role in enhancing Oregon's electric resiliency. Relying upon a relatively small number of large-scale energy resources (e.g., large hydroelectric facilities) that are generally

[99] PacifiCorp and BPA, January 18-19, 2011.

located along the Columbia River places such facilities at risk, especially to natural causes and terrorist threats. In general, renewable resources are located a reasonable distance from these existing hydroelectric facilities. Adverse events that impact a relatively small geographic area would, therefore, affect fewer electric generating facilities. These facts support the argument that renewable resources positively affect Oregon's energy resiliency.

Electric Grid Diversity

Traditional large-scale electric generating facilities require high-voltage transmission and substation interconnections to be reliably and safely connected to the grid. In contrast, individual renewable resource projects generally represent a smaller amount of capacity than traditional large-scale electric facilities. Consequently, grid interconnections may occur at relatively lower voltage levels. Transmission system events (e.g., terrorist attacks) that directly affect the high-voltage system would not necessarily impact renewable resources. Hypothetically, an attack on Oregon's high-voltage transmission system could result in the loss of large-scale generating facilities without adversely impacting distributed or renewable resources. From the perspective of energy resiliency, promoting electric grid diversity generally improves Oregon's electric resiliency.

Response Time

It is impossible to predict, with any specificity, the causes or ramifications of large-scale events that result in threats to Oregon's electric resiliency. However, it is reasonable to assume that such events would cause incumbent utilities to engage in repair and restoration projects that could require a significant amount of time, human resources, and capital to complete. Taking these generalizations one step further suggests that required remediation for larger scale facilities (e.g., hydroelectric generation, substations or high-voltage transmission lines) would require more lead time for equipment procurement than for smaller facilities. As noted above, since renewable and distributed resources are generally smaller in scale, it can then be argued that they might become operational faster than their large-scale counterparts.

Energy versus Capacity

Electric utilities commonly perceive limits to the value that renewable resources provide to the electric grid. Most importantly, renewables are considered to be a source of energy, but not of capacity.[100] The capacity of renewable resources is effectively controlled by their capacity factor, which is discussed elsewhere in this Report.

[100] Electric generating units are not continuously available to supply the electric needs of customers. Consequently, units are assigned a capacity factor to effectively de-rate their maximum capacity. The capacity factor of an individual electric generating unit is computed as the ratio of actual energy produced in a given period of time (usually, one year) to its hypothetical maximum or nameplate capacity.

Reliability and Dispatch

Electric utilities in Oregon do not include renewable resources in their emergency operating plans.[101] One reason is that renewable resources are considered to be less reliable than conventional resources. Reliability, or the likelihood that resources will perform when called upon, is expressed as the resource's capacity factor (as average or expected available capacity over the course of a year) and capacity value (as the available capacity during periods of peak demand). Wind resources have a capacity factor of 35 percent, which suggests that 65 percent of the installed capacity will not be available when called upon to operate over the course of one year. The results for solar resources are even more notable since its capacity factor is 15 percent. In contrast, conventional resources commonly have a capacity factor that is greater than 85 percent. For example, if the total installed capacity of a hypothetical wind farm is 1,000 kW and its capacity factor is 35 percent, then the facility's effective capacity is only 350 kW. During emergency conditions, the 1,000 kW wind farm would be expected to have a capacity of 350 kW. The value that renewable resources provide to energy resiliency is dependent upon their ability and probability to be available to operate during emergency conditions.

During emergency conditions, adequate capacity is necessary for electric resiliency, but it is not sufficient. Oregon's utilities will also need to look to voltage and frequency control to maintain safe and reliable operations. BPA and PacifiCorp stated that the renewable resources that are currently integrated into Oregon's grid are not capable of providing voltage and frequency control.

Grid Integration

Oregon's framework for promoting renewable resources into electric resiliency requires accommodation of the problems and challenges that come from system integration requirements. Section 4 presents the issues that affect integration. Recommendations for future actions to address those issues include:

- Streamline rights-of-way procurement for renewable resources.
- Facilitate financial incentives for energy storage.
- Promote and coordinate incumbent utilities accommodation of renewable resources in plans for emergency response.

Impact Assessment

The impact that renewable resources will have on electric resiliency depends on how large a role renewables play in electric dispatch and generation. Renewable resources are likely to reflect a significant percentage of Oregon's total portfolio mix in 2025, as required by Oregon's RPS. Given the above stated difficulties in its reliability and possibility of instantaneously exiting the dispatch queue, associated impacts could be

[101] Interview with PacifiCorp staff on January 18, 2011.

significant. System studies which reflect peak demand conditions and peak renewable generation under variable output conditions were not available.

Ancillary Services

Oregon's RPS for future renewable resources will create new demands and challenges for ancillary services, especially in the areas of energy dispatch, voltage and frequency regulation, and hour-ahead forecasting. Over time, the increase in renewable resources is expected to be accompanied by a reduction in the dispatch, and possibly the commitment of conventional resources. Having fewer conventional resources on-line might create difficulties in maintaining voltage and frequency control. This condition is not unique to Oregon and is considered to be of concern in other states as well.

Regulatory and Utility Response to the Framework

The regulatory and utility response to the above opportunities and challenges should focus on facilitating Smart Grid applications to grid optimization, promoting energy storage (e.g., batteries, fuel cells, flywheels, pumped hydroelectric), applying a new outlook or approach to valuing renewable resources, and facilitating a sea-change in traditional utility operations and planning. The following table summarizes how these opportunities match the above issues.

Table 5-1
Strategic Framework Response

Issue	Regulatory Response
Fuel Diversification	Valuation of Renewables
Geographic Diversity	Valuation of Renewables
Electric Grid Diversity	Smart Grid
Response Time	System Operations and Planning
Energy Versus Capacity	Valuation of Renewables
Reliability and Dispatch	Energy Storage
Grid Integration	Energy Storage
Impact Assessment	System Operations and Planning
Ancillary Services	Smart Grid
Bidding Strategies	System Operations

Smart Grid Technology Roadmap

Many utilities are planning, implementing, or considering deployment of Smart Grid pilots or full scale projects. The reason many utilities are interested in Smart Grid is varied, but a variety of Smart Grid technologies enables utilities to reduce peak power demand, improve the utilization of transmission and distribution assets, encourage customers to use energy more efficiently, integrate renewable power sources, and improve electric service reliability.

The framework or approach described in the previous Section will identify gaps between the desire to accommodate the integration of renewable power sources and Smart Grid technologies, and prioritize where availability and reliability of electric service may be improved at important public facilities throughout Oregon. Outcomes from this suggested framework or approach is suggested to be the starting point (i.e., Item 1 in the outline below) for Oregon policy makers and regulators to consider a technology roadmap that encourages deployment of Smart Grid technologies and integration of renewable power sources that improve the availability and reliability of electric service at important public facilities. An outline of this technology roadmap is provided below:

1. **Identify important public facilities where electric service reliability may be lower, no conventional standby backup generation is available, and the operation of an important public facility is most impacted with the loss of electric service during a power outage.** Electric utilities and state and local officials responsible for emergency response and hazard mitigation plans may cooperate to identify areas where Smart Grid technology demonstrations and projects may be deployed to improve the reliability of transmission and distribution assets serving important public facilities that are most impacted by potential power outages.

2. **Consider requiring the state's utilities revise their outage restoration plans to include important public facilities among the utilities' service restoration priorities during power outages.** Also, state and local officials responsible for emergency response and hazard mitigation plans may meet with individual electric utilities to establish procedures or protocols to prevent loss of electric service at important public facilities if a load curtailment emergency occurs (not including under frequency protection) and utilities are required to implement their emergency load shed plans.

   The emergency load shed plans of many utilities includes discontinuing electric service at the distribution feeder or substation level in response to a major load curtailment event. Discontinuing electric service at the distribution feeder line or substation level interrupts electric service to many important public facilities normally fed by these feeder lines or substations. Utilities that have two-way AMI meters and service switches or are planning to deploy AMI projects may enact an emergency load shed by remotely disconnecting service at the customer level in lieu of at the distribution feeder line or substation level without interrupting service to important public facilities or customers that have home life support. There may be a number of Oregon utilities, however, that do not currently have two-way AMI and have no immediate plans to deploy AMI. In such cases where emergency load shed cannot be revised to prevent discontinuing electric service at important public facilities, state and local officials responsible for emergency response and hazard mitigation plans may consider the installation of conventional standby generation or renewable power sources (see net metering tariffs below).

3. **Consider establishing minimum functionality requirements for any AMI project proposed by the state's utilities.** These minimum functionality requirements may be recommended by the PUC and include near real-time monitoring and control of distribution operations needed to provide decision support and improve reliability, i.e., two-way communication capabilities, 15-minute interval meter reads needed for alternative rate designs, remote service switches for connect/disconnect operations, detection of overloads and under voltage that may lead to outages, support of in-home displays, programmable thermostats, direct load control, and other devices to reduce peak power demand. Many of these same technologies may be used to monitor and control on-site conventional standby generators or renewable power sources installed at important public facilities to mitigate risks associated with a power outage or emergency load curtailment.

4. **Longer term, policy makers and regulators may require utilities to describe how data from AMI and Smart Grid technologies, pilots, and projects will be archived and utilized to improve utility asset management, operations, maintenance, planning processes, and ultimately electric service reliability.** Examples include using Smart Grid sensors and AMI to develop robust load profiles of customer classes, monitoring the condition, loading, and performance of transmission and distribution equipment, and monitoring system disturbances and events used in outage management systems. Each of these has an impact on energy assurance planning as they affect the utility's ability to reliably provide electricity during emergency conditions.

   Similarly, transmission and distribution operators need data to quantify meaningful demand response programs and measures, anticipated impacts on transmission and distribution operations, and verification that utility demand response and load control programs reduce peak demand and maintain system reliability. In addition, alternative retail rate designs may be developed to encourage energy efficiency and net metering policies needed to integrate and monitor customer-owned renewable power sources. Examples of alternative retail rate designs include net metering tariffs and rates under which utilities purchase power from customers that have renewable power sources, time of use rates, peak rebate programs, critical peak pricing, etc.

5. **Consider implementing alternative electric rate programs.** The two-way communications capabilities that are integral in smart meters (AMI) can support alternative electric rate programs, which are commonly referred to as demand response. Such programs include real-time pricing, time-of-use, critical peak pricing and incentive-based programs. The overarching objectives of these programs are to assist Oregon's utilities in achieving its future energy requirements, improve service reliability, reduce environmental impacts and control capital requirements. PGE conducted a pilot program for critical peak pricing, which was curtailed in September 2010.[102]

[102] "Tariff update Announcement," PGE, September 22, 2010, http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/tariff_updates/Update_09_22_10.pdf

Section 6
RECOMMENDED NEXT STEPS

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Section 6
RECOMMENDED NEXT STEPS

Introduction

The overarching objective of this Report is to provide the ODOE with information that will assist in the promotion of the integration of renewable energy and new applications, such as Smart Grid technologies, into energy assurance and emergency preparedness plans. One key attribute is to provide ODOE and the PUC with specific recommendations for more detailed studies, including the specific information gaps and the need for additional studies. Our response to these requirements is found below.

Information Gaps and Recommendations for Future Studies

This Report touches upon certain topics where information or specific studies are not currently available. Such topics are listed here with the intent to direct ODOE's and the PUC's future efforts in the integration of renewable energy and Smart Grid technologies to promote electric energy resiliency.

Available information was provided by various organizations, including the ODOE, PUC, BPA, WECC, U.S. DOE, EIA, and NETL. All of which is considered to be in the public domain. Confidential information was not provided or utilized.

One important example of unavailable data is the backup energy capabilities of Oregon's emergency service providers. Such information is relevant to EAP analysis as energy gaps, during emergencies, could inhibit the provisioning of critical services. Future research should include collecting data on electricity requirements (e.g., peak demand, electric energy, backup capacity and fuel, access to portable generators), natural gas (peak usage, on-site storage), petroleum, diesel, and other fuel data (normal usage, critical usage, on-site storage capacity).

Ideally, the above information would be assembled for each emergency service provider's critical facility in the form of a spreadsheet. Requirements by each type of energy resource would be compared to backup capabilities (including renewables and energy storage) to identify gaps. Such gaps are the primary basis for assessing vulnerability (e.g., exposure) on a site-by-site basis and collectively.

Tariff Regulation

It is recommended that the PUC encourage utilities to invest in DA, AMI, and Smart Grid to improve monitoring and control of the transmission and distribution systems, improve grid reliability and resiliency, and promote the integration of renewable electric resources.

Uniform Integration Standard and Policies

Oregon's technical standards, procedures or agreements that facilitate expedited, low-cost and straightforward interconnection policies for renewable resources should be reviewed with the intent to understand and address regulatory impediments.[103] It is recommended that the PUC and ODOE investigate additional streamlining of the renewable integration process and include energy assurance planning.

Access to Electric Markets

Some renewable and distributed generators have argued that it is not easy or feasible to participate in local or regional markets for electricity. It is recommended that the Oregon PUC examine the impact that minimum thresholds have on statewide renewable resource development.

Rate Base Uncertainty

Conversations with Oregon's utilities indicate that there is some uncertainty in whether costs associated with Smart Grid related technologies will be approved for inclusion in the utility's rate base. It is recommended that the PUC address such uncertainties and clarify which costs and under what circumstances such costs will be included in rate base.

Revenue Incentives

Distributed generators effectively reduce customer's required energy and demand and, thereby, present a financial disincentive to utility participation. It is recommended that the PUC investigate incentive mechanisms to encourage utilities to embrace and promote renewable and distributed generation.

Multiple Impacts

One area of concern in energy assurance planning is to understand the potential that singular events might create multiple adverse effects. This scenario is illustrated in recent events where an earthquake in one location (Japan) causes a tsunami that subsequently causes multiple adverse impacts.[104] Analogous events could happen in Oregon. A forest fire could impact multiple critical electric transmission lines, railroads, and highways. An earthquake could impact multiple electric transmission lines and natural gas and petroleum pipelines. A terrorist attack or flooding on the Columbia River could impact numerous hydroelectric dams. The examination of critical assets should include geographic information to assess events that are contained in a relatively small geographic area. Such information should include:

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[103] "Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations", Oregon PUC, February 2005.
[104] International Atomic Energy Agency at http://www.iaea.org/newscenter/news/tsunamiupdate01.html

- Routes and capacities of specific natural gas pipelines.
- Routes and capacities of high-voltage electric transmission lines.
- Detailed geographic information for critical assets that would facilitate identifying assets that are in close proximity to each other.

Smart Grid Implementation

Utilizing available Smart Grid technologies to facilitate the integration of renewable resources to promote electric resiliency requires the PUC to promote utility analysis of the costs and benefits of the following:

- Direct load control
- Substation automation
- Distribution automation
- Outage management systems
- Transmission synchrophasors
- Charging services for and from electric vehicles
- Dynamic electric pricing
- Fault detection, isolation, and restoration

Each of the above can potentially improve Oregon's electric resiliency and deserves appropriate consideration. To date, the PUC has provided little guidance or incentive to Oregon's utilities to address the costs and benefits of Smart Grid related technologies.

Electric Utility Operations

Conversations with Oregon's key electric utilities indicate that they are generally concerned about energy assurance planning. However, their specific, formal plans are either not available or non-existent. It is recommended that the PUC direct Oregon's utilities to create an emergency plan that extends beyond NERC criteria and includes the following specific information:

- Locations of existing candidate micro-grids that might serve emergency service providers
- Operating plans for micro-grids
- Locations, numbers, and capacities of portable generators
- Plans for the utilization of portable generators to support customer operations, especially emergency stakeholders
- Under- and over-frequency load and generation curtailment plans
- Studies identifying the application of distributed generators

Emergency Stakeholders

Oregon's emergency service providers play an important role in the state's energy assurance plans. Yet, key information about such entities and their dependence on energy is either poorly understood or was unavailable to us. This information gap should be addressed and a list of Oregon's emergency service providers and their pertinent attributes should be compiled. ODOE should examine the potential energy gaps that might exist, and assess the effects that such gaps have on the state's energy resiliency. The following information should be collected/analyzed:

- Specific locations of emergency service providers (e.g., public safety, red cross, national guard, hospitals)
- Specific energy backup capabilities that are located at each emergency stakeholder's location (e.g., type of backup electric generator, fuel, capacity, duration of use)
- Specific emergency energy requirements for each emergency stakeholder
- Gaps between emergency energy requirements and backup capabilities (coupling of the above two items)

APPENDICES

Appendix A
CRITICAL FACILITIES

Region 1: Bridges and Culverts

County	State Highway Bridges	State Highway Culverts	County Highway Bridges	County Highway Culverts	City/Municipal Highway Bridges	City/Municipal Highway Culverts	Historic Covered Bridges	2006 Total
Clatsop	109	72	65	78	12	4	0	340
Coos	138	49	115	159	4	2	1	468
Curry	60	29	30	39	1	1	0	160
Douglas*	8	71	2	276	2	1	0	360
Lane*	12	112	3	347	3	3	1	481
Lincoln	137	105	85	170	3	4	4	508
Tillamook	144	81	91	147	7	4	0	474

* Data for only the coastal portions of the Counties were not available.
Source: Oregon Department of Transportation, 2006, Oregon Department of Fish and Wildlife, Statewide Culvert Inventory

Region 1: Critical Facilities

County	Hospitals		Police Station	Fire & Rescue Station	School Districts & Colleges
	# of Hospitals	# of Beds			
Clatsop	2	83	6	11	5 SDs, 1 Community College
Coos	3	151	7	17	7 SDs, 1 Community College
Curry	1	24	4	11	3 SDs
Douglas*	2	198	8	27	14 SDs, 1 Community College
Lane*	4	578	8	24	15 SDs, 1 Community College, 1 State University
Lincoln	2	85	4	8	1 SD, 1 Community College
Tillamook	1	49	5	8	3 SDs, 1 Community College

* Data for only the coastal portions of the Counties were not available.
Sources: State Hospital Licensing Department, USAcops.com, Oregon State Fire Marshall, Oregon Department of Education

Region 1: Power Plants and Dams

County	Power Plants[105]	Dams[‡] (State)	Threat Potential
		Dams	
Clatsop	0	7	3 High Threat
Coos	0	24	2 High Threat
Curry	0	13	0 High Threat
Douglas*	0	86	9 High Threat
Lane*	1 – 51.2 MWs	54	11 High Threat
Lincoln	0	8	4 High Threat
Tillamook	0	5	0 High Threat

* Data for only the coastal portions of the Counties were not available.
Source: Oregon Department of Energy, Oregon State Water Resources

Region 2: Bridge Inventory

County	State Highway Bridges	County Highway Bridges	City/Municipal Highway Bridges	Historical Covered Bridges	Total
Clackamas	162	159	10	0	331
Columbia	60	95	7	0	162
Multnomah	333	44	126	1	504
Washington	171	185	29	0	385

Source: Oregon Department of Transportation, 2006

Region 2: Public Airports

County	Commercial Service	Reliever Airport	General Aviation	Helipad
Clackamas	0	0	4	0
Columbia	0	0	2	0
Multnomah	1	1	0	1
Washington	0	1	2	0
Total	1	2	8	1

Source: FAA Airport Master Record (Form 5010)

[105] Includes all electric generating facilities.

Region 2: Critical Facilities

County	Hospitals: # of Hospitals	Hospitals: # of Beds	Police Stations	Fire & Rescue Stations	School Districts & Colleges
Clackamas	4	443	8	17	10 Districts, 1 Community College, 1 University
Columbia	0	0	6	6	5 Districts
Multnomah	8	1,833	11	43	8 Districts, 2 Community Colleges, 5 Universities
Washington	3	647	14	23	7 Districts, 2 Community Colleges, 1 University

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 2: Power Plants and Dams

County	Power Plants	Dams: # of Dams	Dams: # High Threat
Clackamas	0	39	7
Columbia	0	5	0
Multnomah	1 – 250 MW	17	8
Washington	0	21	4

Source: Oregon Department of Energy, National Inventory of Dams

Region 3: Bridge Inventory

County	State Highway Agency	County Highway Agency	City/Municipal Highway Agency	Historical Covered Bridges	Total
Benton	78	107	26	3	214
Lane*	392	429	62	18	901
Linn	219	336	32	8	295
Marion	180	150	68	2	400
Polk	67	120	10	1	198
Yamhill	68	137	1	1	207

* These figures do not include coastal areas.
Source: Oregon Department of Transportation

Region 3: Public and Private Airports

County	Commercial Service	General Aviation (Public)	General Aviation (Private)	Helipad (Private)
Benton	0	1	9	1
Lane	1	6	10	9
Linn	0	4	20	1
Marion	0	2	14	9
Polk	0	1	7	1
Yamhill	0	3	14	3
Total	1	17	74	24

Source: FAA Airport Master Record (Form 5010)

Region 3: Critical Facilities

	Hospitals				
County	# of Hospitals	# of Beds	Police Station	Fire & Rescue	School Districts & Colleges
Benton	1	134	7	5	3 Districts, 1 University
Lane	4	650	9	18	6 Districts, 1 Community College, 1 University
Linn	2	131	4	7	3 Districts, 1 Community College
Marion	3	424	17	18	9 Districts, 1 University
Polk	1	36	4	3	2 Districts, 1 University
Yamhill	2	102	11	10	6 Districts, 2 Universities

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 3: Power Plants and Dams

		Dams	
County	Power Plants	#	# High Threat
Benton	0	6	2
Lane	2 – 552 MW	34	9
Linn	1 – 93 MW	11	7
Marion	0	20	2
Polk	0	17	1
Yamhill	1 – 119 MW	25	1

Source: Oregon Department of Energy, National Inventory of Dams

Region 4: Bridge Inventory

County	State Highway Bridges	County Highway Bridges	City/Municipal Highway Bridges	Historical Covered Bridges	Total
Douglas	302	309	18	0	629
Jackson	222	159	19	0	400
Josephine	101	122	2	0	225

Source: Oregon Department of Transportation

Region 4: Public Airports

	Number of Airports by FAA Designation			
County	Commercial Service	Public Airport	Private Airport	Private Helipad
Douglas	0	4	14	5
Jackson	1	3	11	6
Josephine	0	2	4	3
Total	1	9	29	14

Source: FAA Airport Master Record (Form 5010)

Region 4: Critical Facilities

	Hospitals				
County	# of Hospitals	# of Beds	Police Station	Fire & Rescue Station	School Districts & Colleges
Douglas	1	126	12	27	13 Districts, 1 Community College
Jackson	3	430	3	19	9 Districts, 1 University
Josephine	1	103	11	33	2 Districts, 1 Community College

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 4: Power Plants and Dams

		Dams	
County	Power Plants	# of Dams	Threat Potential
Douglas	7	53	9 High Threat
Jackson	4	50	15 High Threat
Josephine	0	7	1 High Threat

Source: Oregon Department of Energy, National Inventory of Dams, Atlas of Oregon

Region 5: Bridges and Culverts

County	State Highway Bridges	State Highway Culverts	County Highway Bridges	County Highway Culverts	City/Municipal Highway Bridges	City/Municipal Highway Culverts	Historic Covered Bridges	2006 Total
Gilliam	16	35	17	0	0	0	0	68
Hood River	37	38	18	0	0	0	0	93
Morrow	25	35	43	1	10	1	0	115
Sherman	34	46	9	1	0	1	0	91
Umatilla	119	105	247	7	23	0	0	501
Wasco	58	46	88	24	5	0	0	221

Source: Oregon Department of Transportation, 2006

Region 5: Critical Facilities

County	Hospitals		Police Station	Fire & Rescue Station	School Districts & Colleges
	# of Hospitals	# of Beds			
Gilliam	0	0	3	2	2 Districts
Hood River	1	25	2	6	1 District
Morrow	1	12	4	5	2 Districts
Sherman	0	0	1	5	1 District
Umatilla	3*	158*	11	16	10 Districts, 1 Community College
Wasco	1	49	2	8	3 Districts, 1 Community College

* These totals include one psychiatric hospital with a 60-bed capacity.
Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 5: Power Plants and Dams

County	Power Plants	Dams		
		Dams† (State)	Dams‡ (National)	Threat Potential
Gilliam	0	0	0	0 High Threat
Hood River	0	10	5	1 High Threat
Morrow	2 power plants, 1,053 MW	8	13	2 High Threat
Sherman	0	11	6	1 High Threat
Umatilla	3 power plants, 1,137 MW	21	14	3 High Threat
Wasco	0	29	19	6 High Threat

Source: Oregon Department of Energy, National Inventory of Dams. Table updated July 2006.

Region 6: Bridges and Culverts

County	State Highway Bridges	State Highway Culverts	County Highway Bridges	County Highway Culverts	City/Municipal Highway Bridges	City/Municipal Highway Culverts	Historic Covered Bridges	2006 Total
Crook	27	26	26	3	6	0	0	88
Deschutes	41	17	46	3	31	2	1	141
Jefferson	14	12	34	0	3	0	0	63
Klamath	58	42	180	18	10	0	0	308
Lake	26	29	40	228	1	0	0	324
Wheeler	23	34	6	0	0	0	0	63

Source: Oregon Department of Transportation, 2006, Lake County Integrated road Information System, 2007

Region 6: Critical Facilities

County	Hospitals		Police Station	Fire & Rescue Station	School Districts & Colleges
	# of Hospitals	# of Beds			
Crook	1	35	1	1	1 District
Deschutes	2	264	7	7	4 Districts, 1 Community College
Jefferson	1	36	4	3	4 Districts, 1 Community College
Klamath	1	176	5	17	2 Districts, 1 Community College, 1 State University
Lake	1	21	2	6	5 Districts
Wheeler	0	0	1	4	3 Districts

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 6: Power Plants and Dams

County	Power Plants	Dams		
		Dams† (State)	Dams‡ (National)	Threat Potential
Crook	0	57	40	3 High Threat
Deschutes	0	18	18	4 High Threat
Jefferson	0	17	15	5 High Threat
Klamath	2 plants, 570 MW	66	54	4 High Threat
Lake	0	82	53	2 High Threat
Wheeler	0	18	13	0 High Threat

Source: Oregon Department of Energy, National Inventory of Dams. Table updated July 2006.

Region 7: Bridges and Culverts

County	State Highway Bridges	State Highway Culverts	County Highway Bridges	County Highway Culverts	City/Municipal Highway Bridges	City/Municipal Highway Culverts	Historic Covered Bridges	2006 Total
Baker	80	110	80	3	7	0	0	280
Grant	43	63	36	1	9	0	0	152
Union	69	54	67	0	6	0	0	196
Wallowa	21	39	58	2	11	2	0	133

Source: Oregon Department of Transportation, 2006

Region 7: Critical Facilities

County	Hospitals: # of Hospitals	Hospitals: # of Beds	Police Station	Fire & Rescue Station	School Districts & Colleges
Baker	1	36	2	13	4 Districts
Grant	1	25	3	7	5 Districts
Union	1	49	4	7	6 Districts, 1 State University
Wallowa	1	25	1	4	4 Districts

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 7: Power Plants and Dams

County	Power Plants	Dams: Dams‡ (State)	Dams: Dams§ (National)	Dams: Threat Potential
Baker	0	92	51	6 High Threat
Grant	0	34	18	1 High Threat
Union	0	34	25	4 High Threat
Wallowa	0	9	6	2 High Threat

Source: Oregon Department of Energy, National Inventory of Dams. Table updated July 2006.

Region 8: Bridges and Culverts

County	State Highway Bridges	State Highway Culverts	County Highway Bridges	County Highway Culverts	City/Municipal Highway Bridges	City/Municipal Highway Culverts	Historic Covered Bridges	2006 Total
Harney	37	22	106	0	0	0	0	165
Malheur	70	94	130	0	2	0	0	296

Source: Oregon Department of Transportation, 2006

Region 8: Critical Facilities

County	Hospitals: # of Hospitals	Hospitals: # of Beds	Police Station	Fire & Rescue Station	School Districts & Colleges
Harney	1	44	4	4	10 Districts
Malheur	1	49	4	9	11 Districts, 1 Community College

Source: State Hospital Licensing Department, Local Sheriff Offices, Oregon State Fire Marshall, Oregon Department of Education. Table updated July 2006.

Region 8: Power Plants and Dams

County	Power Plants	Dams: Dams‡ (State)	Dams: Dams§ (National)	Dams: Threat Potential
Harney	0	93	54	0 High Threat
Malheur	0	164	68	8 High Threat

Source: Oregon Department of Energy, National Inventory of Dams. Table updated July 2006.

Appendix B
OREGON STATE HIGHWAYS

Primary Highways

Hwy. No.	Highway Name	Route Number
001	Pacific Hwy	I-5, OR99, OR99E, OR138, US30
002	Columbia River Hwy	I-84, US30, US395, US730
003	Oswega Hwy	OR43
004	The Dalles-California Hwy	US20, US26, US97, US197, OR140, OR216
005	John Day Hwy	US26, US395, OR19, OR207
006	Old Oregon Trail Hwy	I-84, US30, US395
007	Central Oregon Hwy	US20, US26, US395, OR201
008	Oregon-Washington Hwy	OR11
009	Oregon Coast Hwy	US26, US101
010	Wallowa Lake Hwy	OR82
011	Enterprise-Lewiston Hwy	OR3
012	Baker-Copperfield Hwy	OR7, OR86, I-84
014	Crooked River Hwy	OR27
015	McKenzie Hwy	OR216, OR242, OR126Bus
016	Santiam Hwy	US20, OR126
017	McKenzie-Bend Hwy	US20
018	Willamette Hwy	OR58
019	Fremont Hwy	US395, OR31, OR140
01E	Pacific Hwy East (Hwy 081 in ITIS)	OR99E, OR214
01W	Pacific Hwy West (Hwy 091 in ITIS)	OR99, OR99W, OR126, OR126Bus, OR10
020	Klamath Falls-Lakeview Hwy	OR39, OR140
021	Green Springs Hwy	OR66
022	Crater Lake Hwy	OR62
023	Dairy-Bonanza Hwy	OR70
025	Redwood Hwy	OR99, US199
026	Mt Hood Hwy	US26, US30, OR35
027	Alsea Hwy	OR34
028	Pendleton-John Day Hwy	US395
029	Tualatin Valley Hwy	OR8, OR47
02W	Lower Columbia River Hwy (092 in ITIS)	US30
30	Willamina-Salem Hwy	OR22
031	Albany-Corvallis Hwy	US20
032	Three Rivers Hwy	OR22

Hwy. No.	Highway Name	Route Number
033	Corvallis-Newport Hwy	US20, OR34
035	Coos Bay-Roseburg Hwy	OR99, OR42
036	Pendleton-Cold Springs Hwy	OR37
037	Wilson River Hwy	OR6
038	Oregon Caves Hwy	OR46
039	Salmon River Hwy	OR18, OR22, OR233
040	Beaverton-Hillsdale Hwy	OR10
041	Ochoco Hwy	US26, OR126
042	Sherman Hwy	US97
043	Monmouth-Independence Hwy	OR51
044	Wapinitia Hwy	OR216
045	Umpqua Hwy	OR99, OR38
046	Necanicum Hwy	OR53
047	Sunset Hwy	US26, OR47
048	John Day-Burns Hwy	US395
049	Lakeview-Burns Hwy	US395
050	Klamath Falls-Malin Hwy	US97Bus, OR39, OR140
051	Wilsonville-Hubbard Hwy	
052	Heppner Hwy	OR74, OR207
053	Warm Springs Hwy	US26
054	Umatilla-Stanfield Hwy	OR32, US395
058	Albany-Junction City Hwy	OR99E
059	Sandy Blvd Hwy	US30Bus
060	Rogue River Hwy	OR99
061	Stadium Freeway	I-405
062	Florence-Eugene Hwy	OR126
063	Rogue Valley Hwy	OR99
064	East Portland Freeway	I-205, OR212, OR213
066	LaGrande-Baker Hwy	US30, OR203, OR237
067	Pendleton Hwy	US30
068	Cascade Hwy North	OR213
069	Beltline Hwy	OR126
070	McNary Hwy	I-82
071	Whitney Hwy	OR7
072	Salem Parkway	
073	North Umpqua Hwy	OR138

Appendix C
SYSTEM INTEGRATION

The IEEE has adopted a standard that addresses system integration, which is commonly used throughout the United States of America (U.S.)[106] The requirements of that standard are voluminous and may be significantly prohibitive in some applications. An abbreviated set of issues that are addressed in the standard include the following:[107]

- Voltage regulation: The generator may not actively regulate voltage at the point of interconnection (see the American National Standards Institute [ANSI] C84.1-1995).
- Grounding: The generator's grounding scheme may not cause overvoltages and not disrupt the coordination of the ground fault protection on the local power system.
- Synchronization: The generator shall parallel with the local power system without causing a voltage fluctuation of $\pm$ 5 percent.
- Network protectors: Network protectors shall not be used to separate, switch, or serve as breaker failure backup to isolate the generator.
- Connection: Connection of the generator is only permitted if the local power system bus is already energized by more than 50 percent of the installed network protectors.
- Cycling: The generator output shall not cause any cycling of network protectors.
- Fault interruption: The network equipment loading and fault interrupting capacity shall not be exceeded.
- Blackstart: The generator shall not energize the local power system when such system is de-energized.
- Monitoring: Each generator of 250 kVA or more shall have provisions for monitoring its status.
- Isolation: A readily accessible, lockable, visible-break isolation device shall be located between the local power system and the generator.
- Electromagnetic interference: The interconnection shall have the capability to withstand electromagnetic interference in accordance with IEEE Standard C37.90.2-1995.

[106] "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," IEEE Standard 1547, dated July 28, 2003.
[107] This list of attributes is generally based on IEEE Standard 1547, is presented as an illustration of the magnitude and nature of interconnection requirements, but is not intended to be used to plan, design or construct such interconnections.

- Surge protection: The interconnection system shall have the capability to withstand voltage and current surges in accordance with IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002.
- Paralleling device: The interconnection shall be capable of withstanding 220 percent of the interconnection system rated voltage.
- Faults: The generator shall cease to energize the local power system during faults.
- Reclosing: The generator shall cease to energize the local power system prior to reclosure operations.
- Voltage sensing: Voltages shall be detected either at the point of interconnection or at the generator.
- Voltage based clearing times: The generator shall be able to respond to abnormal voltages at prescribed clearing times.
- Frequency: Adjustable under-frequency trip settings shall be coordinated with local operations and prescribed clearing times.
- Reconnection: No generator reconnection shall take place until the local power system is within prescribed standards (ANSI C84.1-1995).
- Interconnection delay: The generator interconnection shall include an adjustable delay.
- Direct Current (DC) injection: The generator shall not inject DC greater than 0.5 percent of its full rated output.
- Voltage flicker: The generator shall not create objectionable flicker for other customers.
- Harmonics: The generator shall not cause harmonic current injection into the local power system that exceeds prescribed limits.
- Islanding: For unintentional islanding, the generator interconnection must detect the island and cease to energize the local power system within two seconds. Intentional islanding is currently under consideration by the IEEE.
- Design test: Design tests shall be performed.
- Response to abnormal frequency: The generator shall demonstrate that it will cease to energize the local power system when voltage or frequency exceeds prescribed limits.
- Synchronization: Test results must demonstrate the generator's adherence to criteria, including surge withstand performance, paralleling, unintentional islanding, limitation of DC injection, harmonics, production, grounding, isolation device performance, monitoring, fault clearing, reclosing coordination, commissioning, and periodic interconnection tests.

The above list is not intended to be comprehensive and one should read IEEE Standard 1547 in its entirety.

~A~

AMI: Advanced Metering Infrastructure

AMR: Automated Meter Reading

ANSI: American National Standards Institute

ARRA: American Recovery and Reinvestment Act

ATM: Automated Teller Machines

~B~

Bcfd: billion cubic feet per day

BCP: Blackstart Capability Plan

bdt: bone dry tons

Blackout: unplanned loss of electricity

BPA: Bonneville Power Administration

Btu: British thermal unit

~C~

Capacity Factor: Electric generating units are not continuously available to supply the electric needs of customers. Consequently, units are assigned a capacity factor to effectively de-rate their maximum capacity. The capacity factor of an individual electric generating unit is computed as the ratio of actual energy produced in a given period of time (usually, one year) to its hypothetical maximum or nameplate capacity.

Capacity Value: The demand for electricity is not constant throughout the year. Periods of peak demand commonly follow weather conditions, where coldest and hottest days are associated with increased air conditioning or heating. The capacity value of an individual generating unit is computed as the ratio of actual energy produced in a given period of time (usually, one year) to its hypothetical maximum or nameplate capacity – only during peak demand conditions.

CIP: Critical Infrastructure Protection

CLP: Central Lincoln People's Utility District

CO: Central Office

CO_2: carbon dioxide

CREFF: Community Renewable Energy Feasibility Fund

~D~

DA: Distribution Automation

DC: Direct Current

DOGAMI: Oregon Department of Geology and Mineral Industries

DR: Demand Response

~E~

EAP: Energy Assurance Plan

EIA: U.S. Department of Energy, Energy Information Administration

EOC: Emergency Operations Centers

EPA: Environmental Protection Agency

EWEB: Eugene Water & Electric Board

~F~

FCD: Federal Continuity Directives

FERC: Federal Energy Regulatory Commission

~G~

GIS: Geographic Information Systems

GOP: Generator Operator

~H~

HSPD: Homeland Security Presidential Directives

~I~

IAP: Incident Action Plans

ICS: Incident Command System

IEEE: Institute of Electrical and Electronics Engineers

IMT: BPA Incident Management Team

IPC: Idaho Power Company

IRP: Integrated Resource Plan

ISO: Independent System Operator

IT: Information Technology

~J~

JCHA: Joint Commission of Hospital Accreditation

~K~

km: kilometer

kV: kilovolt

kVA: kilovolt Amperes

kW: kilowatt

kWh: kilowatt hours

~L~

LEC: Lane Electric Cooperative

LNG: Liquefied Natural Gas

LO: Liaison Officer

~M~

MAIFI: Momentary Average Interruption Frequency

mcf: thousand cubic feet

MDMS: Meter Data Management System

MMcf: million cubic feet

mph: miles per hour

MW: megawatt

~N~

NASEO: National Association of State Energy Officials

NERC: North American Electric Reliability Corporation

NETL: National Energy Technology Laboratory

NIMS: National Incident Management System

NO_X: nitrogen oxide

NTTG: Northern Tier Transmission Group

NWPCC: Northwest Power and Conservation Council

~O~

OAR: Oregon Administrative Rules

OASIS: Open Access Same-Time Information System

ODOE: Oregon Department of Energy

ODOT: Oregon Department of Transportation

OMS: Outage Management System

OPT: Ocean Power Technologies

ORS: Oregon Revised Statutes

~P~

PDR: Partnership for Disaster Resilience

PG&E: Pacific Gas & Electric

PGE: Portland Gas and Electric

PIO: BPA Public Information Officer

PTC: Federal Production Tax Credits

PUC: Oregon Public Utility Commission

PUD: Public Utility District

PV: photovoltaic

~Q~

~R~

R. W. Beck: SAIC, formerly R. W. Beck, Inc.

REC: Renewable Energy Credits

RPS: Renewable Portfolio Standard

RTO: Regional Transmission Organizations

~S~

SAIC: Science Applications International Corporation

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SCADA: Supervisory Control and Data Acquisition

Staff: WECC Operations Staff

~T~

TBtu: trillion British thermal units

TOP: Western Interconnection Transmission Operators

~U~

U.S.: United States

U.S. DOE: United States Department of Energy

UAMPS: Utah Associated Municipal Power Systems

UMEC: Umatilla Electric Cooperative Association

UPS: Uninterruptable Power Supply

~V~

~W~

WECC: Western Electricity Coordinating Council

~X~

~Y~

~Z~