Portland General Electric Company's Longer Term Local Transmission Plan For the 2014-2015 Planning Cycle

Contents

1. Introduction

This 2015 Longer Term Local Transmission Plan reflects Quarters 5 through 8 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

Projects identified in the Longer Term Local Transmission Plan's six (6) to ten (10) year planning horizon are not committed projects and are subject to modification and/or withdrawal. Projects described herein are not part of PGE's Expansion Plan as described in Section 12.2.3 of Attachment O to PGE's OATT.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in the Northern Tier Transmission Group (NTTG) and the Western Electric Coordinating Council (WECC). PGE uses the NTTG process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on the NTTG's website at www.nttg.biz.

2. Planning Process and Timeline

This plan is for the 2014-2015 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

<table>
<tr><th></th><th></th><th>Quarter</th><th>Tasks</th></tr>
<tr><td rowspan="4">Near Term</td><td rowspan="4">Even Years</td><td>1</td><td>Select Near Term base cases and gather load data</td></tr>
<tr><td>2</td><td>Post Near Term methodology on OASIS, select one Economic Study for evaluation</td></tr>
<tr><td>3</td><td>Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment</td></tr>
<tr><td>4</td><td>Incorporate stakeholder comments and post final Near Term plan on OASIS</td></tr>
<tr><td rowspan="4">Longer Term</td><td rowspan="4">Odd Years</td><td>5</td><td>Gather load data and accept Economic Study requests</td></tr>
<tr><td>6</td><td>Select one Economic Study for evaluation</td></tr>
<tr><td>7</td><td>Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment</td></tr>
<tr><td>8</td><td>Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems</td></tr>
</table>

PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS. Figure 2 shows the meetings held in 2015 and the meetings scheduled for 2016.

Figure 2: Quarterly Customer Meetings

Planning Cycle Quarter	Meeting Date
5	March 3, 2015
6	June 2, 2015
7	September 30, 2015
8	*December 8, 2015*
1	*March 8, 2016*
2	*June 7, 2016*
3	*September 6, 2016*
4	*December 6, 2016*

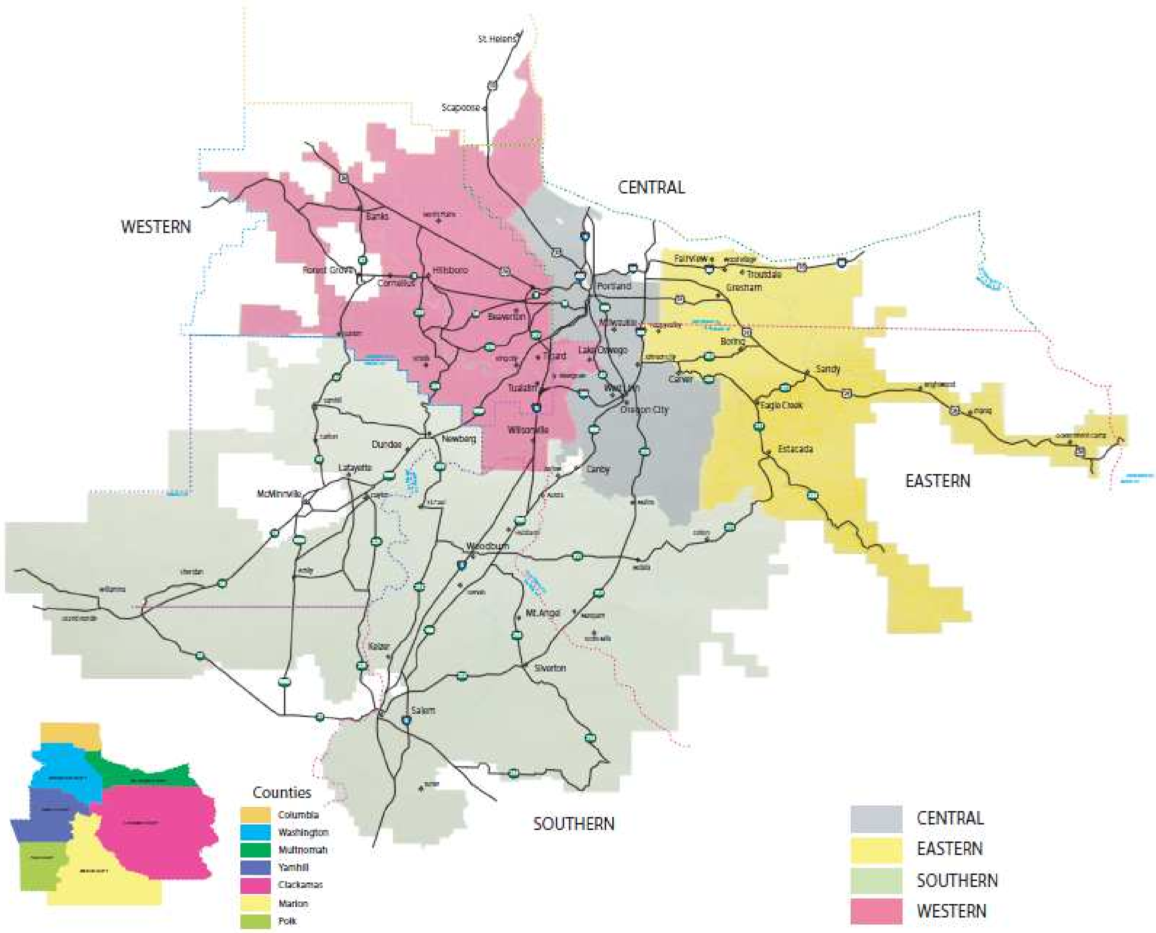
***Meeting dates in *italics* are upcoming and subject to change.**

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers more than 4,000 square miles and provides service to over 825,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 3.

Figure 3: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland & Salem regions for the purpose of serving native load. In addition to the load-service transmission facilities, PGE also maintains ownership of networked Transmission System circuits (See Figure 4) used to integrate transmission and generation resources on the Bulk Electric System.

Figure 4: PGE-Owned Transmission System Circuits

Transmission Circuit	Circuit Miles	Transmission Path
Grizzly-Malin 500kV	178.5 miles	COI[1]
Grizzly-Round Butte 500kV	15.6 miles	
Colstrip-Townsend #1 500kV	37.3 miles (15% ownership)	
Colstrip-Townsend #2 500kV	36.9 miles (15% ownership)	
Bethel-Round Butte 230kV	99.2 miles	WOCS[2]
St Marys-Trojan 230kV	41.4 miles	SOA[3]
Rivergate-Trojan 230kV	35.1 miles	SOA

In total, PGE owns 1,590 circuit miles of sub-transmission/transmission at voltages ranging from 57kV to 500kV. (See Figure 5)

Figure 5: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	270	319
115 kV	496	551
57 kV	430	451

3.2. Load Forecast

For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the Peak Reliability Seasonal System Operating Limits Coordination Process, Appendix 'V'.

[1] California-Oregon Intertie
[2] West of Cascades South
[3] South of Allston

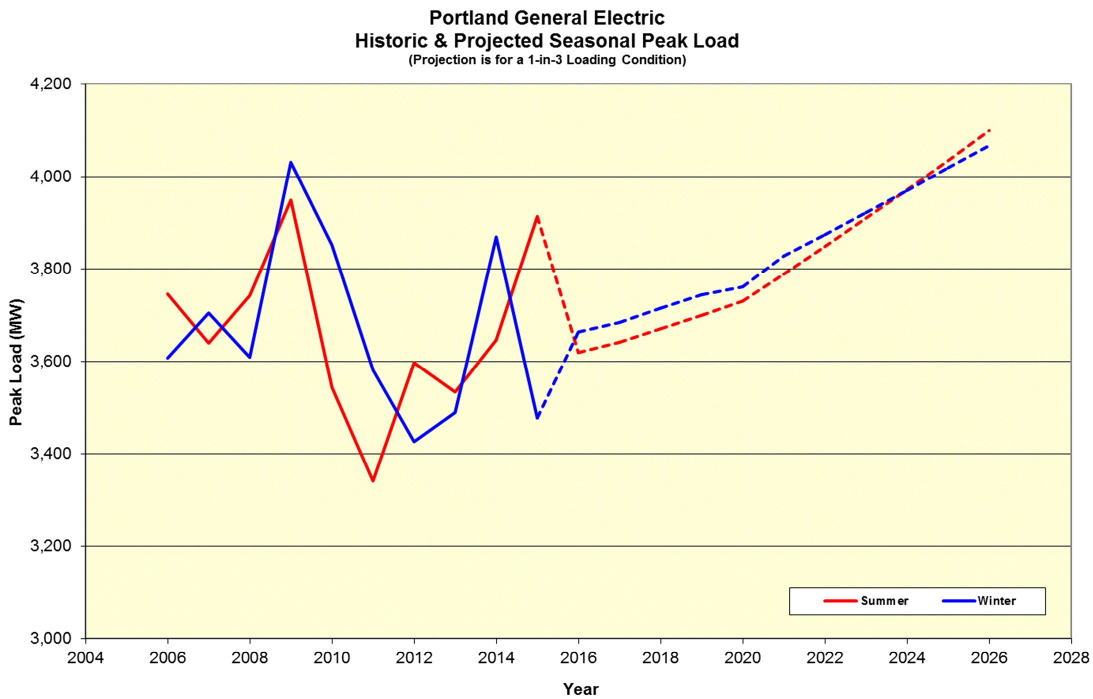
Figure 6: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	79ºF
1-in-3	81ºF
1-in-5	83ºF
1-in-10	85ºF
1-in-20	87ºF

Winter	
1-in-2	28ºF
1-in-3	24ºF
1-in-5	21ºF
1-in-10	18ºF
1-in-20	15ºF

Figure 7: Portland General Electric's Historic & Projected Seasonal Peak Load

(Projection is for a 1-in-3 Loading Condition)



As depicted in Figure 7, PGE's all-time peak load occurred on December 21, 1998, with the Net System Load[4] reaching 4073 MW. PGE's all time summer peak occurred on July 29, 2009 with the Net System Load reaching 3949 MW.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

[4] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2014-2015 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Longer Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2014-2015 planning cycle.

4. Methodology

PGE's transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecasted system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet performance requirements.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-010-0 and MOD-012-0 reliability standards. Electrical facilities modeled in the cases have established normal and emergency ratings, as defined in PGE's Facility Ratings Methodology document. A facility rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-3 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115kV transmission system (primarily auto mode - time-clock; two auto mode - voltage control) and on the 57kV transmission system (auto mode - voltage control).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load model used in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Transmission equipment is assumed to be out of service in the Base Case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for one of the five years

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak system sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 8: Powerflow Base Cases Used in 2015 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Operating Case	2015	2015 HS4-OP	15 HS OPERATING	3657
	Year One/Two Case	2017	2015 HS4-OP	17 HS PLANNING	3642
	Year Five Case	2020	2020 HS2	20 HS PLANNING	3730
	Year One/Two Sensitivity	2017	2015 HS4-OP	17 HS SENSITIVITY	3839
	Year Five Sensitivity	2020	2020 HS2	20 HS SENSITIVITY	3932
	Long Term Case	2025	2024 HS1	25 HS PLANNING	4034
WINTER	Operating Case	2015	2014-15 HW3-OP	14-15 HW OPERATING	3711
	Year One/Two Case	2016-17	2014-15 HW3-OP	16-17 HW PLANNING	3685
	Year Five Case	2020-21	2019-20 HW1	20-21 HW PLANNING	3828
	Year One/Two Sensitivity	2016-17	2014-15 HW3-OP	16-17 HW SENSITIVITY	3923
	Year Five Sensitivity	2020-21	2019-20 HW1	20-21 HW SENSITIVITY	4176
	Long Term Case	2025-26	2023-24 HW1	25-26 HW PLANNING	4068
SPRING	Operating Case	2015	2015 HSP1	15 HSP OPERATING	3041
	Near Term Off Peak Case	2017	2017 LSP1-S	17 LSP PLANNING	2427
	Near Term Off Peak Sensitivity	2017	2017 LSP1-S	17 LSP SENSITIVITY	2427

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P1 events. For P2-P7 events, PGE identifies distribution substations where manual post-contingency "load-shedding" may be required to ensure that the Transmission System remains within the defined operating limits.

4.2. Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500kV and 230kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with Delayed Fault Clearing.

For all 500kV and 230kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500kV and 230kV facilities; and the majority of 115kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated against the performance requirements outlined in the NERC TPL-001-4 reliability standard and against the WECC Disturbance-Performance Table of Allowable Effects on Other Systems (Table I). The simulation durations are run to 20 seconds.

Figure 9: WECC Disturbance-Performance Table of Allowable Effects on Other Systems[5]

WECC and NERC Categories	Outage Frequency Associated with the Performance Category	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
A (P0)	Not Applicable	Nothing in addition to NERC		
B (P1)	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C (P2-P7)	0.033-0.33	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D (Extreme)	< 0.033	Nothing in addition to NERC		

Contingency analyses simulate the removal of all elements that the Protection System and other automatic controls expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models
- Automatic controls simulated include generator exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

5 The WECC TPL-001-WECC-CRT Regional Criterion is currently undergoing a revision to adapt the new categories (P0-P7) in the NERC TPL-001-4 reliability standard.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Steady State Results – Longer Term Evaluation

There are no contingency loading or voltage concerns on PGE's system in the Longer Term Planning Horizon for NERC TPL-001-4 Categories P1, P2, P3, P4, and P5. NERC TPL-001-4 Category P6 and P7 contingency overloads and voltage concerns are addressed with load shedding, as permitted, on PGE's local distribution system. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2. Longer Term Transient Stability

The Longer Term transient stability studies indicate that PGE's Transmission System exhibits adequate transient stability throughout the 500kV and 230kV transmission systems. The minimum transient frequency response recorded did not dip below 59.6 Hz for any of the contingency events studied on PGE's Transmission System. Underfrequency Load Shedding ("UFLS") relays are not affected because the set point for UFLS relays is 59.3 Hz. The transient voltage dip did not exceed 25% at any load bus or 30% at any non-load bus for any of the contingency events studied on PGE's Transmission System. 5.3. Projects Currently Included in the Longer Term Plan

There are five projects currently planned for implementation in the Longer Term Planning Horizon.

Projects described in this Longer Term Plan are subject to modification and/or withdrawal.

Potential projects are described in detail in Appendix A.

Appendix A: 10 Year Project List

Potential projects currently included in the Longer Term Plan are:

- Blue Lake/Gresham Phase II Project
- Carver-McLoughlin Phase II Project
- Harborton Reliability Project
- Northern 115kV Conversion Project
- Pearl-Sherwood 230kV Project

These projects are described in more detail on the following pages.

Blue Lake/Gresham Phase II Project

- **Project Purpose**
  - Address transmission operations flexibility and aging asset concerns by installing a second bulk power transformer at Blue Lake substation, which facilitates future decommissioning of Linneman substation.

- **Project Scope**
  - Install a second bulk power transformer at Blue Lake substation.
  - Construct a new 115kV circuit to McGill substation.
  - Construct a new 115kV circuit to Tabor substation.

- **Project Status**
  - Preliminary planning

- **Project Requirement Date**
  - No date established; TBD

Carver-McLoughlin Phase II Project

- **Project Purpose**
    - Address loading concerns on the Carver-Sellwood 115kV circuit by reconfiguring the system to create a Carver-McLoughlin #3 115kV line.

- **Project Scope**
    - Install a new 115kV circuit on the vacant side of the existing Carver-McLoughlin #2 230kV circuit tower line.
    - The existing 115kV which currently routes through Clackamas substation will become a Carver-McLoughlin #3 115kV line.
    - The new 115kV line will become the new Canemah-Carver 115kV line.

- **Project Status**
    - Preliminary planning

- **Project Requirement Date**
    - No date established; TBD

Harborton Reliability Project

- **Project Purpose**
  - Address transmission operations flexibility for the loss of the Rivergate bulk power transformer.
  - Reconfigure the system to reduce exposure and provide a stronger source to the Northwest Portland 115kV system.

- **Project Scope**
  - Rebuild the Harborton 115kV yard to a breaker and one half configuration.
  - Build a new 230kV breaker and one half yard at Harborton substation.
  - Route five 230kV lines to Harborton.
  - Install a new bulk power transformer at Harborton.
  - Reconductor the 115kV lines from Harborton to Canyon.
  - Reconfigure the 115kV system to provide a source to Northwest Portland from Harborton substation.

- **Project Status**
  - Project planning is complete; this project was submitted for inclusion in the 2016 capital budget and was recommended for approval.

- **Project Requirement Date**
  - The project is currently projected for completion in 2021.

Northern 115kV Conversion Project

- **Project Purpose**
  - Convert Northern substation from 57kV to 115kV.
  - Facilitates future construction of an Albina PACW-Knott PACW-St Johns BPA 115kV circuit to address contingency loading and voltage concerns in the North Portland area.

- **Project Scope**
  - Convert Northern substation to a 115kV breaker station.
  - Loop Northern substation into the Curtis-Rivergate #2 115kV circuit, creating a Curtis-Northern 115kV circuit and a Northern-Rivergate 115kV circuit.

- **Project Status**
  - Preliminary planning; joint project with PACW

- **Project Requirement Date**
  - No date established; TBD

Pearl-Sherwood 230kV Project

- **Project Purpose**
  - Provide transmission operations flexibility in the Pearl BPA-Sherwood area.

- **Project Scope**
  - Install two new 230kV breakers at BPA's Pearl substation.
  - Install two new 230kV breakers at Sherwood substation.
  - Split the Pearl BPA-Sherwood 230kV paralleled circuit and terminate each circuit on separate breakers at BPA's Pearl substation and Sherwood substation.
  - Split the paralleled section of the three-terminal McLoughlin-Pearl BPA-Sherwood 230kV circuit and terminate each circuit on separate breakers at BPA's Pearl substation and Sherwood substation.

- **Project Status**
  - Preliminary planning; joint project with BPA

- **Project Requirement Date**
  - No date established; TBD