2017 Biennial Transmission Expansion Plan

ColumbiaGrid

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Acknowledgements

ColumbiaGrid Members & Participants

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Bonneville Power Administration
Chelan County PUD
Cowlitz County PUD
Douglas County PUD
Grant County PUD
Puget Sound Energy
Seattle City Light
Snohomish County PUD
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Executive Summary

The ColumbiaGrid 2017 Biennial Transmission Expansion Plan (Expansion Plan Update) looks out over a ten-year planning horizon (2017 - 2027) and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve load and meet firm transmission service commitments.

Since the adoption of the 2016 Update to the 2015 Biennial Transmission Expansion Plan, the following information has become available and is incorporated into this Expansion Plan:

1) In August 2016, ColumbiaGrid staff completed its 2016 System Assessment which highlighted areas of the system where there may be deficiencies in meeting reliability standards. Three areas from previous System Assessments, Okanogan, Northern Intertie Transfer, and South of Allston, have been resolved. Fifteen areas of concern were identified that affect ColumbiaGrid Planning Participants and still require resolution. All of these problem areas were identified in previous system assessments. Most of these concerns will be addressed by existing study teams or by the affected member(s).

These fifteen Areas of concern consist of: Pearl-Sherwood, Bend, Yakima/Wanapum, Portland, Centralia, Salem-Eugene, Sandpoint/Idaho, Spokane, SnoKing/Everett, Othello, Headwork/Summer Falls, Puget Sound, Palouse, Orofino, and Olympic Peninsula areas.

2) The 2015 System Assessment also identified the need for the following sensitivity studies which are documented in this report.
a. Denny – Broad Street and Massachusetts – Broad Street inductor Switching Study
b. N-1-1 Outage Study
c. Five-Year Extra Heavy Winter Study
d. Transient Stability Study

3) The ColumbiaGrid Ten Year Plan was updated to reflect the most current thinking of the member utilities.

4) Order 1000 Planning Process. In 2015, ColumbiaGrid started a new planning process which complies with both the PEFA and Order 1000 Functional Agreement. This resulted in additional activities such as the evaluation of Order 1000 Needs and reevaluation of Order 1000 Projects that need to be included in the scope of System Assessment. The new process provides additional opportunity for interested persons to submit written suggestions to be considered as Order 1000 Potential Needs and discussed during a public meeting. It also required ColumbiaGrid to reevaluate the most recent plan to determine if changes in circumstances and other facts may require evaluation of alternative transmission solutions which include Order 1000 projects. This report provides more information regarding this activity.

5) Economic Planning Studies. In this planning cycle, ColumbiaGrid has included Economic Planning Studies as a part of its annual study program. This type of study focuses on evaluating future system performance and trans-

mission usage by simulating hourly system behavior using Production Cost Simulation software. In 2015, ColumbiaGrid completed another study which focuses on 2017 system conditions. A summary of the progress is included.

6) Third-Party Physical Security Risk-Assessment Verifications. Transmission Owners must perform a risk assessment to identify the transmission stations and substations that, if rendered inoperable or damaged could result in instability, uncontrolled separation, or cascading within an Interconnection. ColumbiaGrid has begun performing third-party physical security risk assessment verifications required by NERC for five of its planning parties, all of which are currently members of ColumbiaGrid.

7) Study Team Updates. This report also provides the latest status as well as updates from Study Teams such as Puget Sound, Othello, Mid-Columbia and others.

ColumbiaGrid has documented all of these items in this Expansion Plan which has been reviewed by the various study teams and other interested stakeholders. With the completion of this Expansion Plan, ColumbiaGrid will initiate the 2017 System Assessment which is scheduled for completion in July 2017.

Resolution to adopt the 2017 Biennial Transmission Expansion Plan

WHEREAS, a purpose of ColumbiaGrid is carrying out the ColumbiaGrid Planning and Expansion Functional Agreement ("PEFA"), which is intended to support and facilitate multi-system planning through a coordinated, open, and transparent process and is intended to facilitate transmission expansion based upon such planning; and

WHEREAS, pursuant to Article 2.1 of the PEFA, each Planning Cycle, ColumbiaGrid shall develop and review a Draft Biennial Transmission Expansion Plan and shall adopt, by majority vote of the ColumbiaGrid Board of Directors, a Biennial Transmission Expansion Plan; and

WHEREAS, ColumbiaGrid has prepared a Draft 2017 Biennial Transmission Expansion Plan for the years 2017-2027 ("Draft 2017 BTEP") pursuant to PEFA's planning process and posted the Draft 2017 BTEP for public review and comment on January 13, 2017; and

NOW, THEREFORE, BE IT RESOLVED, that based upon the ColumbiaGrid Board of Directors' review of the Draft 2017 BTEP on its technical merits, the consistency of the Projects listed in the Draft 2017 BTEP with the PEFA, and considering comments and information provided during the review process, the ColumbiaGrid Board of Directors hereby adopts the Draft 2017 BTEP as the 2017 Biennial Transmission Expansion Plan.

Introduction

ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. Eleven parties have signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process.

In addition, starting in 2015, ColumbiaGrid has implemented a single transmission planning process that satisfies the requirements under both PEFA and Order 1000. This leads to a more comprehensive process which includes a wide range of studies with different purposes.

ColumbiaGrid's primary grid planning activity is to develop a biennial transmission expansion plan that looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve load and transmission service commitments. A significant feature of the ColumbiaGrid Biennial Transmission Expansion Plan is its single-utility planning approach.

The Biennial Transmission Expansion Plan is being developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be developed if each transmission owner completed a separate independent analysis.

In the years between biennial plans, ColumbiaGrid may produce an update to the biennial plan, if warranted, based on the results of ColumbiaGrid's annual system assessment, study team results or planning participant studies.

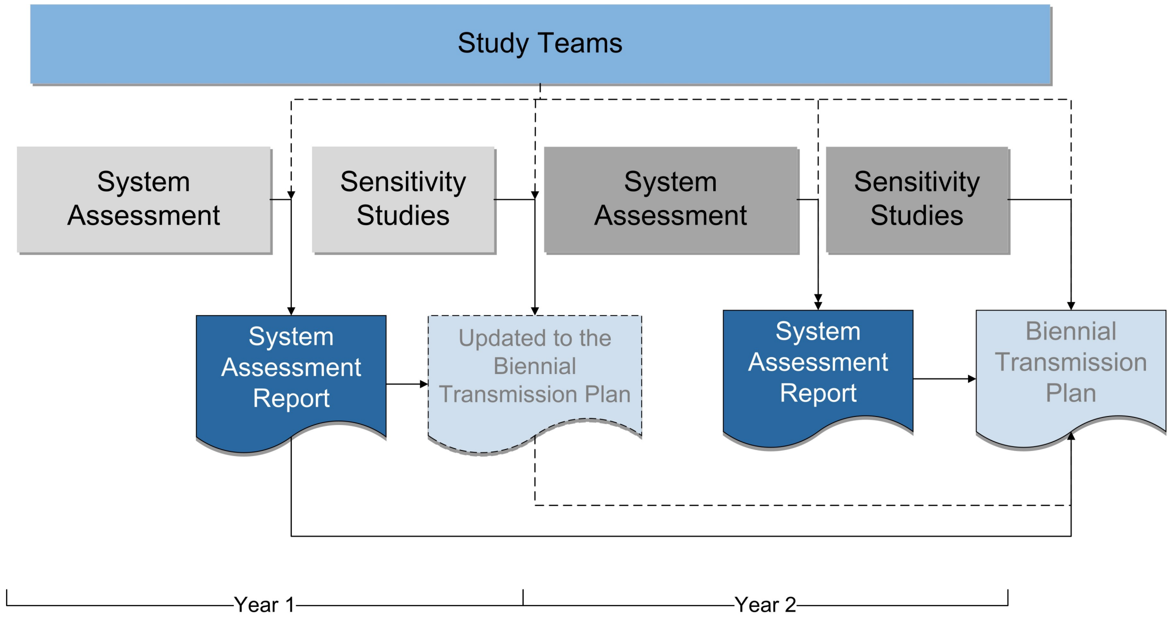


Figure B-1 Process Timeline

Ten Year Plan

The projects in the ten-year plan fill a variety of needs such as serving load, integrating new resources, or facilitating economic transfers. To be included in the plan, the projects are typically committed projects that are in the permitting, design, or construction phases. The projects in the plan may have been generated in a variety of forums such as System Assessments, studies completed by the study teams, or studies completed by individual planning participant studies. Projects from the previous Ten-Year Plan that have since been energized are shown in Table D-1. ColumbiaGrid's current Ten Year Plan is shown in Figure D-1 and Table D-2. More detailed information for each of the projects is provided in Attachment B of this report. Changes in this Plan from the prior plan are also noted along with estimated costs for the ColumbiaGrid member projects. The planning forums that provided review of these projects are also listed.

The ColumbiaGrid ten-year plan has been coordinated directly with neighboring regional planning groups (e.g., the Northern Tier Transmission Group) and with the overall region through the Western Electricity Coordinating Council (WECC). In 2015, WECC developed an overall ten-year plan for the western interconnection (2015 Interconnection-wide Transmission Plan). The current ColumbiaGrid ten-year plan was part of the foundation for the WECC interconnection-wide plan.

The projects in the ColumbiaGrid ten-year plan primarily address issues that occur in the first five years of the ten-year planning horizon. Additional projects will be required to meet the needs in the latter part of the ten-year planning horizon. These additional projects are still being developed as there is sufficient time to study these areas and refine the projects that will address those needs. Several of the long-term needs that may generate additional transmission projects are described in Attachment B.

Joint Areas of Concern

The 2016 System Assessment identified several planning areas with needs that require multiple utility studies during this planning cycle. All of these areas involve load service issues with impacts to ColumbiaGrid participants. Projects that are developed to address these concerns would typically be characterized as Existing Obligation Projects under PEFA. Projects to mitigate these issues are in various stages of development. Some are well defined with firm commitments from the responsible utilities. Others are still in the conceptual stage.

Recurring problem areas from previous System Assessments

The transmission deficiencies identified in the 2016 System Assessment that were also identified in 2015 and prior System Assessments include:

<u>1. Pearl-Sherwood Area</u>

In the heavy summer, heavy winter, and light spring cases, double circuit outage of the BPA Carlton-Sherwood 230 kV and Newberg-Sherwood 115 kV lines overloaded the Forest Grove-Carlton and Sherwood-Springbrook 115 kV lines. These are the same overloads that were identified in last year's assessment. Bonneville and PGE are working on a solution to this double circuit outage problem. These overloads were also identified in the one-year case under heavy summer conditions which will need to be mitigated by operating procedures.

Furthermore, in the heavy summer cases, the five-year and ten-year heavy winter cases, and light spring case, a breaker failure at Carlton 115 kV bus could result in the overload of Dayton-McMinnville Newberg 115 kV line owned by Portland General Electric, which is the same overload that was identified in last year's assessment. Since there is only one ColumbiaGrid member involved, these issues will be the responsibility of the affected parties and no study team is proposed.

<u>2. Bend Area</u>
Several breaker failures that disconnect one of the Pilot Butte 230/69 kV transformers and transmission lines resulted in the overload of the Pilot Butte 230/69 kV transformers in the five-year and ten-year heavy winter cases and all heavy summer cases. PacifiCorp has a procedure to trip all the 69 kV load at Pilot Butte in the event of the loss of two of the three Pilot Butte 69 kV transformers. These facilities are owned by PacifiCorp and Bonneville and these problems were identified in previous system assessments. Since there is only one ColumbiaGrid member involved, these issues will be the responsibility of the affected parties and no study team is proposed.

<u>3. Yakima/Wanapum Area</u>
In the two-year heavy summer case, breaker failures at Wanapum 230 kV bus caused the overload on the Moxee-Hopland 115 kV line. This overload is mitigated by the addition of a third Union Gap 230/115 kV transformer that reduces the power flows on this line to supply load at Union Gap substation. This is the same overload identified in last year's System Assessment.

In the five and ten-year heavy summer cases a breaker failure at the Benton 115 kV bus and in all of the heavy summer cases a double contingency of Benton-Midway #2 230 kV and Benton-Othello 115 kV or a bus outage at Midway #2 could result in the overload of the Bonneville-owned Ashe -White Bluff 230 kV and Sacajawea Tap-Franklin 115 kV lines.

Figure D-2 shows major system configuration in the Yakima/Wanapum area.

<u>4. Portland Area</u>
In the two-year heavy summer case, the Horizon bulk power transformer is overloaded in the base case. The Horizon Phase II project fixes this issue.

In addition, an overload on the Troutdale 230/115 kV transformer in Multnomah County was identified following a breaker failure at the Bonneville Ross 230 kV east bus. However, since there is only one ColumbiaGrid member involved, this issue will be the responsibility of the affected parties and no study team is proposed.

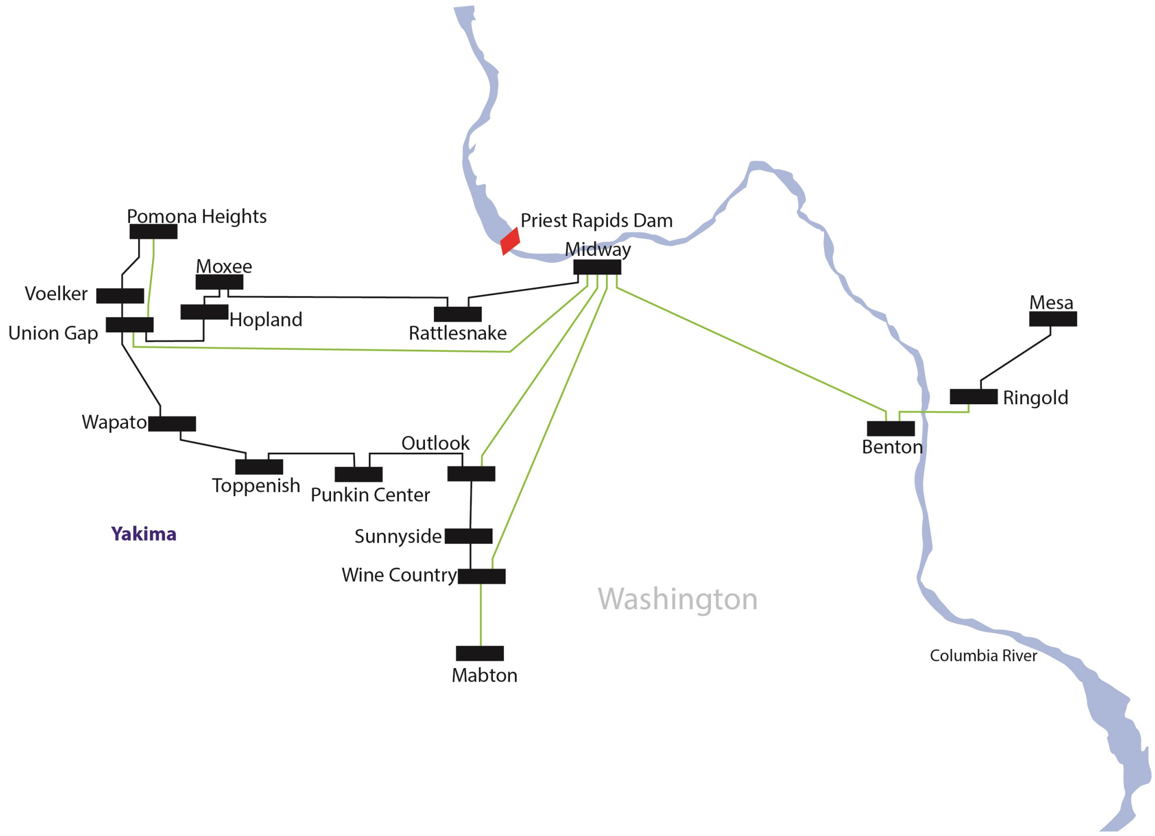


Figure C-1 Yakima/Wanapum Area

5. Centralia Area

In the ten-year winter case, several breaker failures and bus faults in the area of Centralia 500 kV buses did not solve indicating a possible voltage stability issue. Additional analysis indicated that these unsolved cases were caused by both reactive power deficiencies in Olympia and the Olympic Peninsula area, as well as reactive power capability modeling issues. In order to solve this issue, additional reactive support in the Port Angeles area could mitigate these problems. Bonneville is considering load tripping at Port Angeles to correct these potential deficiencies.

6. Salem-Eugene Area

In the heavy summer cases several breaker failures resulting in the loss of the Santiam or Bethel 230 kV buses overloads numerous 115 kV transmission facilities around Oregon City, Fargo, and Chemawa. Since Bonneville is the only ColumbiaGrid member involved in this area, these issues will be the responsibility of the affected parties. No study team is proposed.

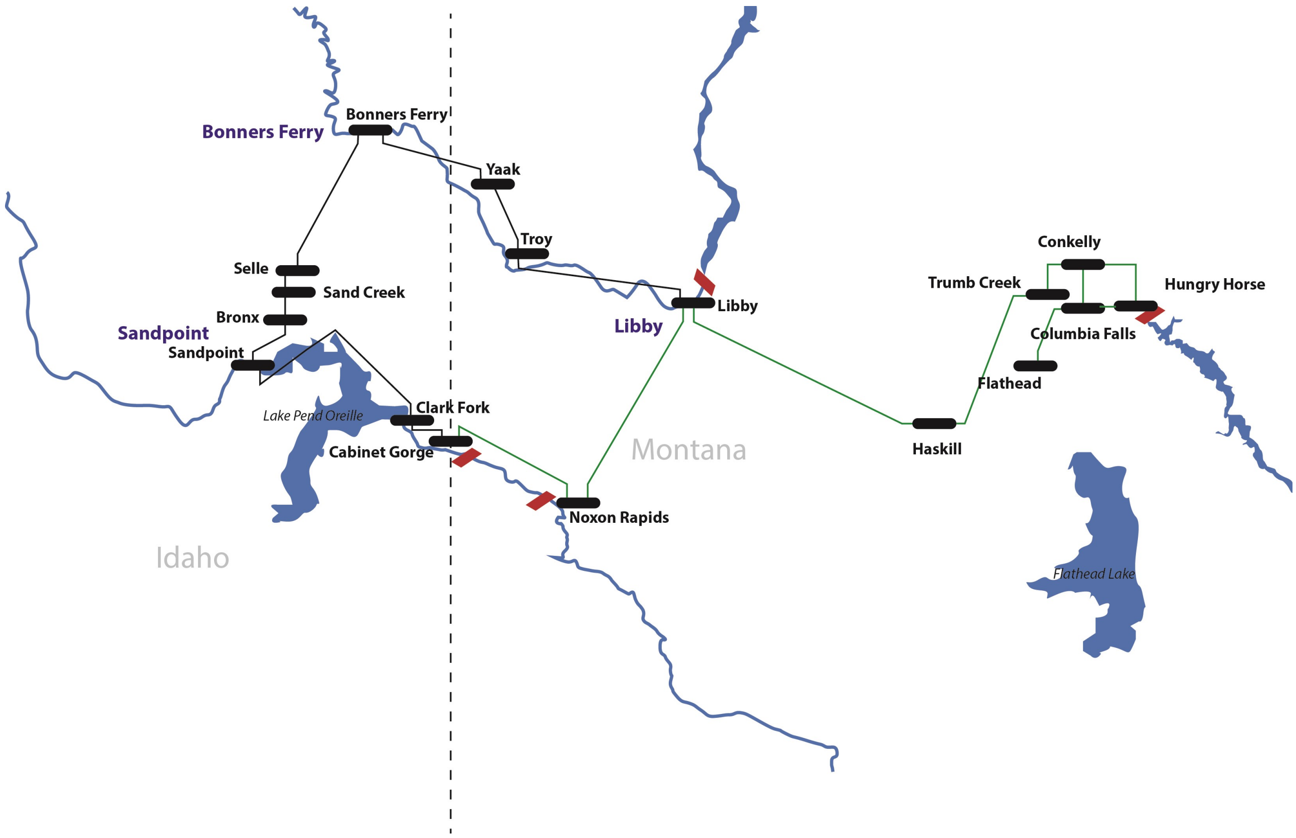


Figure C-2 Sandpoint Area Map

7. Sandpoint, Idaho Area

Similar to last year's study results, several breaker failures, bus outages, single and double contingencies involving the BPA Libby 115 kV bus caused overloads on the Bronx-Sand Point 115 kV line, which is owned by Avista, in the five-year and ten-year summer and winter cases. Similar issues were identified in previous System Assessments for the summer season. Reconductoring the Bronx-Sand Point 115 kV line should mitigate the problem.

Figure D-3 shows major system configuration in the Sandpoint area.

8. Spokane Reliability

A breaker failure at the Beacon 230 kV bus causes overloads on Bell 230/115 kV transformers in the ten-year heavy summer and all winter cases. A breaker failure at the Bell 230 kV bus in the Spokane area resulted in overloads on the Avista owned Westside 230/115 kV transformer in the one-year cases. This problem also showed up in previous years' assessments. The Westside substation upgrade project addresses this issue. These facilities are owned by

Bonneville and Avista and they are working together to address the Bell transformer overload issue. No study team is planned.

Figure D-4 shows major system configuration in the Spokane area.

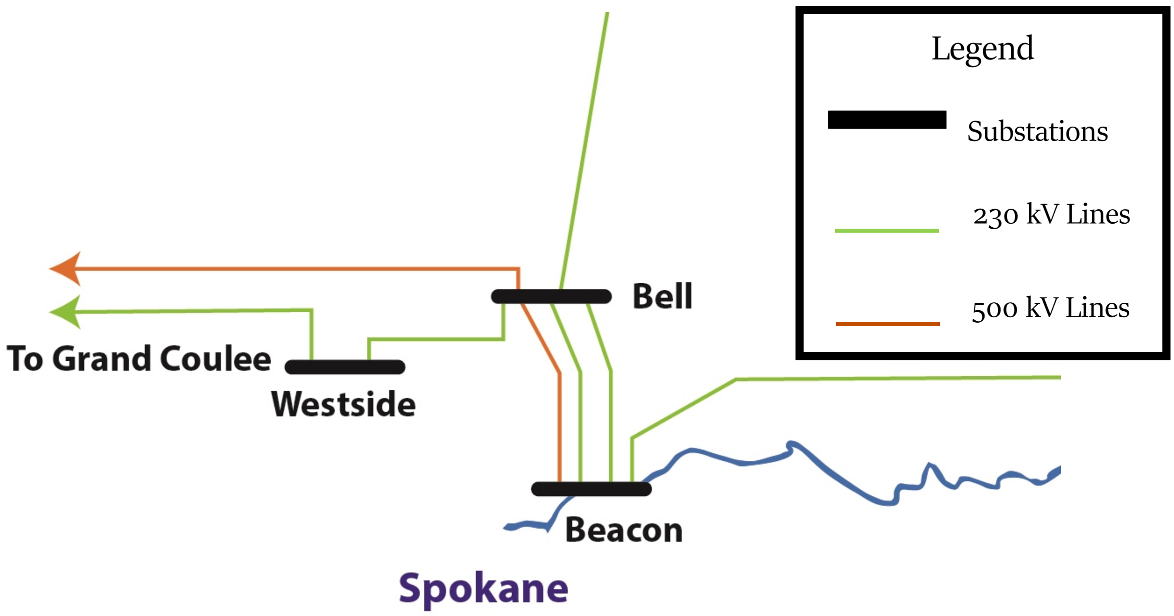


Figure C-3 Spokane Area

9. SnoKing/Everett Area

Several overloads on the Snohomish PUD 115 kV facilities were caused by outages of the SnoKing 115 kV bus in the one-year heavy summer and heavy winter cases. This problem also showed up in previous system assessments. The Swamp Creek Switching Station project in 2018 addresses this issue.

10. Othello

The study results showed that a breaker failure at Grant PUD Sand Dunes 115 kV substation could result in overloads on several Avista owned facilities between Othello and Taunton. These overloads were identified in the one-year and the five-year cases under various heavy summer contingency conditions. However, these problems disappeared in the ten-year case due to the Benton-Taunton-Othello 115 kV line upgrade. Avista and Grant have identified this issue and are exploring a Big Bend area project and study team to resolve these potential overloads.

Figure D-5 shows major system configuration in the Othello area.

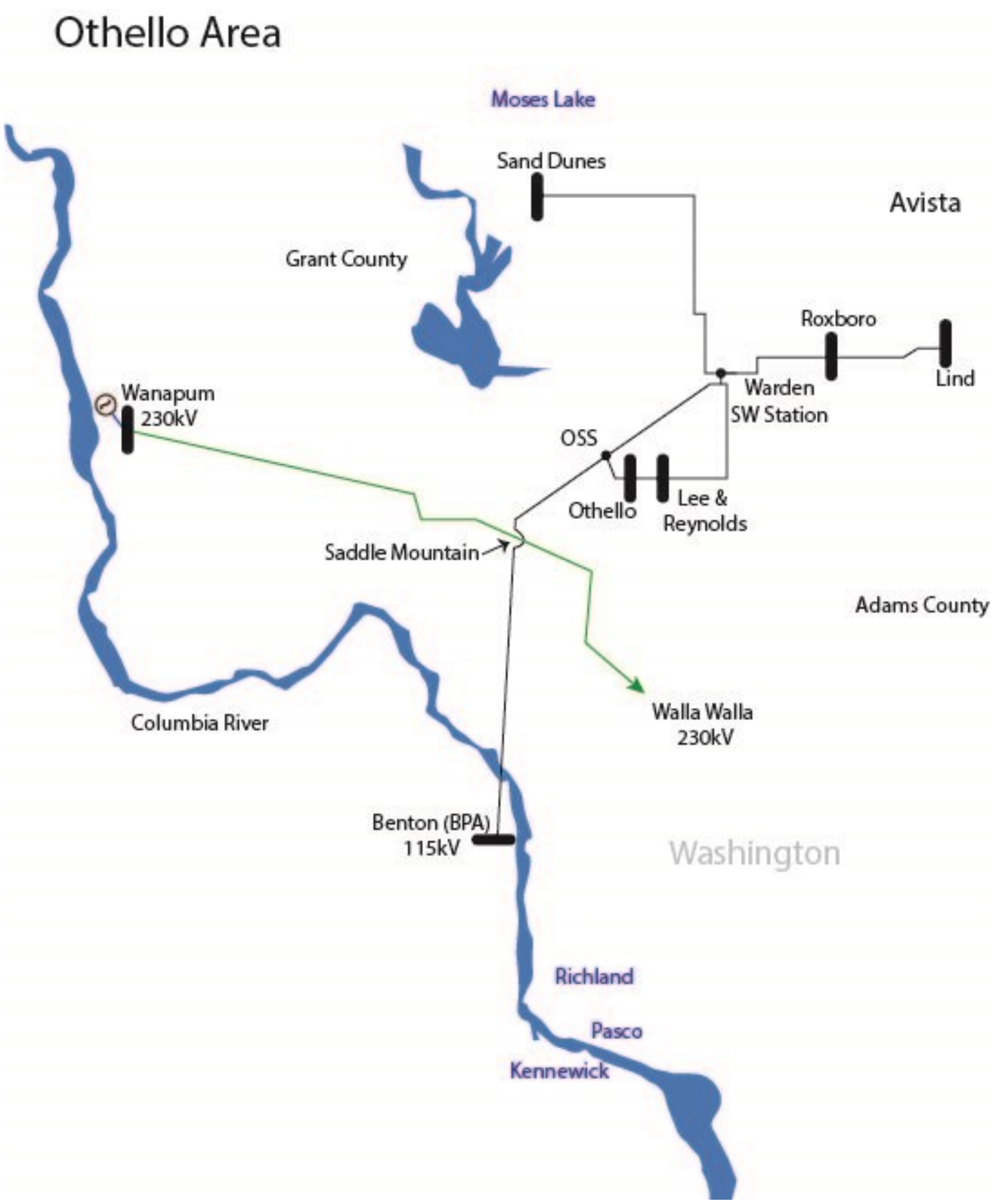


Figure C-4 Othello Area

<u>11. Headwork/Summer Falls Area</u>

In the one-year light spring case, potential overloads on the Avista-owned Headwork-Chelan 115 kV line were identified following various breaker, line and bus outages in Grant PUD's system. These outages disconnect the Larson 230 kV source from the 115 kV network heading into Headwork and Summer Falls. In general, these problems were caused by the combination of low load and high generation during the light summer conditions. In addition, the ratings used in the light summer case are more appropriate to heavy summer conditions. Therefore, it is likely that higher ratings could be applied to this light summer case. Operating procedures which reduce local generation or other operating plans can be used to mitigate these potential overloads.

Figure D-6 shows the system configuration in this area.

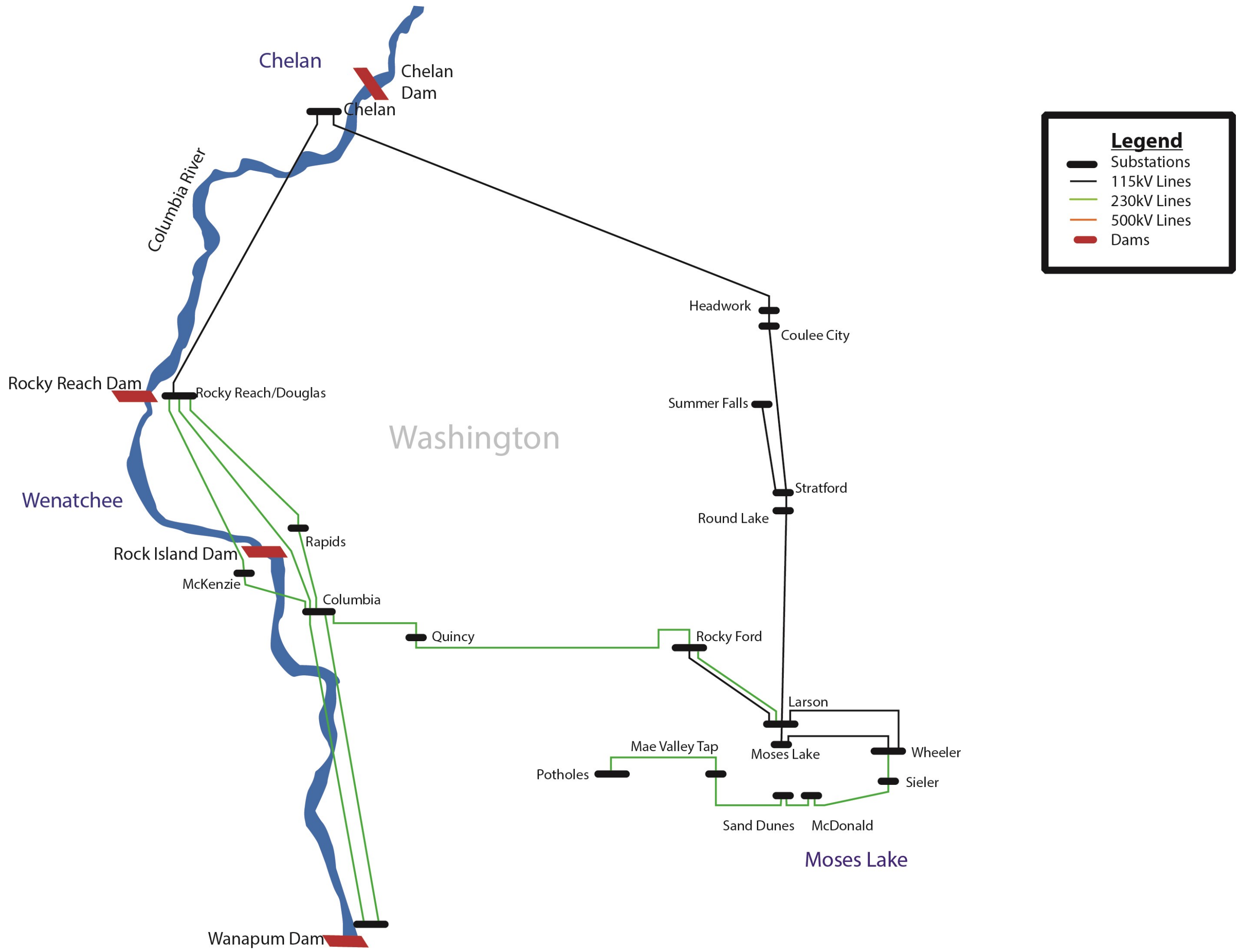


Figure C-5 Headwork/Summer Falls Area Map

<u>12. Puget Sound Area</u>

In the ten-year heavy summer case overloads on Bonneville's Monroe-Novelty 230 kV line and Seattle City Light's North – University and University - Broad 115 kV lines occurred for a 230 kV bus outage at Bonneville's Maple - Valley substation. Several other outages in the heavy summer cases also resulted in an overload to Bonneville's

	Project Name	Sponsor	Date	Change From Last Plan	Cost (Million)	Regional Planning Forum
A1	Bronx-Cabinet 115 kV Rebuild	Avista	2018	Delayed from 2016	$10	ColGrid SA
A2	Benton-Othello 115 kV Line Upgrade	Avista	2018	Delayed from 2016	$10	ColGrid SA
A3	Westside 230 kV Substation rebuild and transformer upgrades	Avista	2018	Delayed from 2016	$15	ColGrid SA
A4	Irvin Project - Spokane Valley Transmission Reinforcements	Avista	2019	Delayed from 2016	$5	ColGrid SA
B1	Paul 500 kV Shunt Reactor	Bonneville Power	2016		$10	ColGrid SA
B2	McNary 500/230 kV Transformer #2	Bonneville Power	2017		$31	ColGrid SA
B3	Big Eddy 230/115 kV Transformer #1 Replacement	Bonneville Power	2017	Delayed from 2015	$10	ColGrid SA
B4	Troutdale 230kV Bus Section Breaker	Bonneville Power	2018		$2	ColGrid SA
B5	Castle Rock - Troutdale 500 kV Line (I-5 Corridor Reinforcement Project)	Bonneville Power	2023	Delayed from 2020	$772	WECC RP
B6	Lower Valley Reinforcement (Hooper Springs)	Bonneville Power	2018	Delayed from 2015	$70	ColGrid SA
B7	Tacoma 230 kV Bus Section Breaker	Bonneville Power	2018		$1	ColGrid SA
B8	Santiam-Chemawa 230 kV Line Upgrade	Bonneville Power	2017		$1	ColGrid SA
B9	Raver 500/230 kV transformer and a 230 kV line to Covington Substation.	Bonneville Power	2018	Delayed from 2017	$60	ColGrid PSAST
B10	Columbia 230 kV Bus Section Breaker	Bonneville Power	2018	Delayed from 2017	$2	ColGrid SA
B11	John Day-Big Eddy 500 kV #1 Line Reconductor	Bonneville Power	2019		$6	ColGrid SA
CO1	Longview-Lexington #2 Upgrade From 69 kV to 115 kV	Cowlitz County PUD	2017		$5	ColGrid SA
CO1	Longview-Lexington-Cardwell Upgrade From 69 kV to 115 kV	Cowlitz County PUD	2017		$10	ColGrid SA
CO2	South Cowlitz County Project	Cowlitz County PUD	2018		$8	ColGrid WST
D1	Rapids-Columbia 230 kV Line and Columbia Terminal	Douglas County PUD	2018		$23	ColGrid NMCST
D2	Lone Pine Substation	Douglas County PUD	2020	New Project	$3	ColGrid SA
D3	Veedol Substation	Douglas County PUD	2017	New Project	$4	ColGrid SA
G1	Rocky Ford - Dover 115 kV Line	Grant County PUD	2017	Delayed from 2016	$5	ColGrid SA
I1	Hemingway - Boardman 500 kV Line	Idaho Power/BPA	2020		$840	WECC RP
P1	Table Mountain 500/230 kV Transformer (On Dixonville - Meridian 500 kV Line)	PacifiCorp	2019			ColGrid SA
P2	Snow Goose 500/230 kV Transformer (On Captain Jack - KFalls Cogen 500 kV Line)	PacifiCorp	2017			ColGrid SA
P3	Vantage-Pomona Heights 230 kV Line (Short Route)	PacifiCorp	2018			ColGrid SA
P4	Union Gap 230/115 kV Transformer #3	PacifiCorp	2017			ColGrid SA
PG1	Troutdale East - Blue Lake - Gresham 230 kV Line (Blue Lake/Gresham 230kV Project)	Portland General Electric	2018			ColGrid SA
PG1	Blue Lake/Gresham Phase II Project	Portland General Electric	2022			ColGrid SA
PG2	Horizon Phase II Project	Portland General Electric	2018			ColGrid SA
PG3	Harborton Reliability Project	Portland General Electric	2021			ColGrid SA
PS1	Alderton 230/115 kV Transformer in Pierce County	Puget Sound Energy	2018		$28	ColGrid SA

Table -1 ColumbiaGrid Ten Year Plan

	Project Name	Sponsor	Date	Change From Last Plan	Cost (Million)	Regional Planning Forum
PS2	Woodland-Gravelly Lake 115 kV Line	Puget Sound Energy	2025		$13	ColGrid SA
PS3	Eastside Project: Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot Line Rebuilt to 230 kV	Puget Sound Energy	2018		$80	ColGrid PSAST
SC1	Bothell-Snoking 230 kV Double Circuit Line Reconductor	Seattle City Light	2018		$4	ColGrid PSAST
SC2	Denny Substation (Phase 1)	Seattle City Light	2018		$209	ColGrid PSAST
SC2	Upgrade Denny Substation Transmission	Seattle City Light	2021		$66	ColGrid PSAST
SC2	Denny - Broad and Massachusetts - Union - Broad 115 kV Series Inductors	Seattle City Light	2018		$22	ColGrid PSAST
SC3	Delridge-Duwamish 230 kV Line Reconductor	Seattle City Light	2018		$6	ColGrid PSAST
SN1	Beverly Park 230/115 kV Transformer	Snohomish County PUD	2018		$25	ColGrid PSAST
SN2	Swamp Creek 115 kV Switching Station	Snohomish County PUD	2018		$6	ColGrid PSAST
SN3	Reconfigure Navy-Everett-Scott	Snohomish County PUD	2021		$7	ColGrid SA
SN4	Turner-Woods Creek 115 kV Line	Snohomish County PUD	2020		$25	ColGrid SA
T1	Potlatch System New Ring Bus Switchyard	Tacoma Power	2018		$5	ColGrid SA
T2	Pearl Cushman Upgrade	Tacoma Power	2018		$6	ColGrid SA
				Total of all ColumbiaGrid	$2,405	

Table C-1 ColumbiaGrid Ten Year Plan Cont...

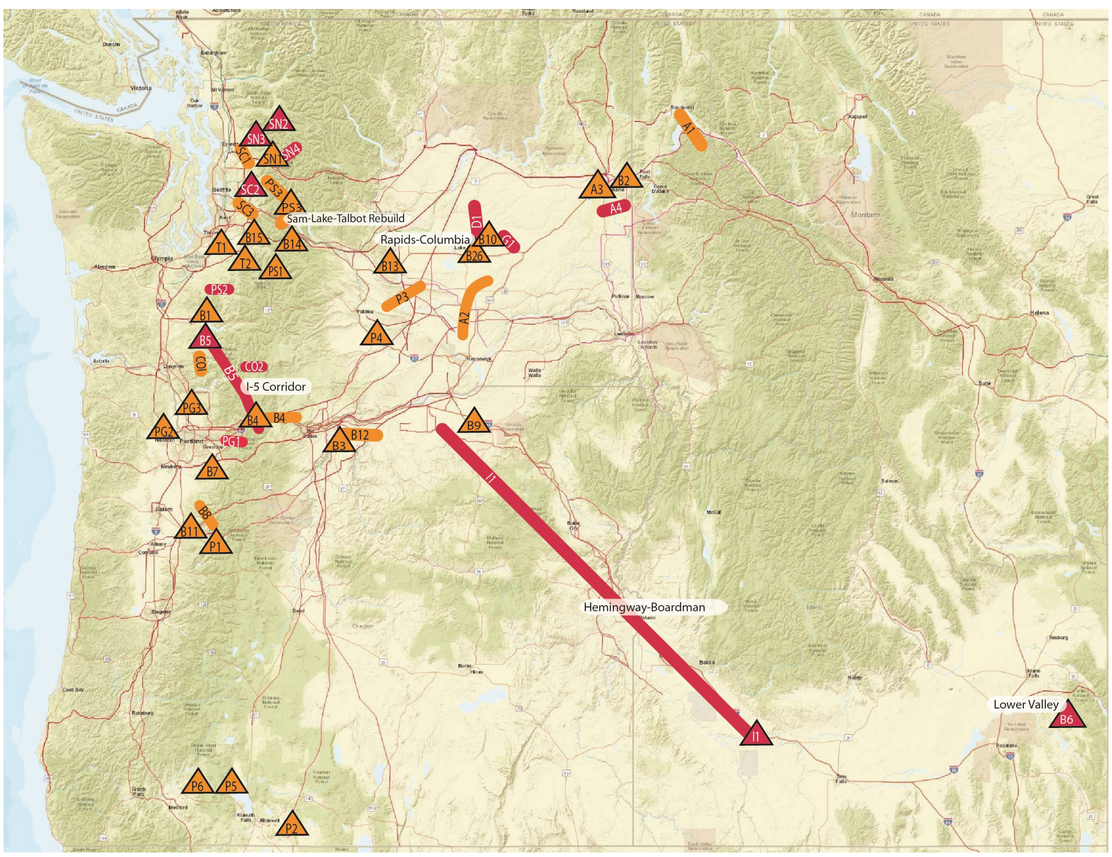


Figure C-6 Ten Year Projects

230 kV Monroe-Novelty line. Overloads are also occurring to the Puget Sound Energy's Alderton – Shaw 115 kV line in the ten-year heavy summer case for an outage of the Raver – Paul 500 kV line. A project is being developed to upgrade both of these lines and should be included in future assessments. Furthermore, overloads on the 115 kV lines near Snohomish PUD's Navy substation could occur in the five-year and ten-year heavy winter cases for a 115 kV bus outage at BPA's Murray substation. Snohomish PUD and BPA are working together to reinforce this area of the network. These issues will be studied and reviewed by the Puget Sound Area Study Team.

<u>13. Palouse/Walla Walla Area</u>

In the ten-year summer case, several breaker failures around the PacifiCorp Walla Walla 230 kV bus involving PacifiCorp and Avista facilities result in overloads on the 115/69 kV Dry Gulch transformer and 230/69 kV Walla Walla transformer. Sectionalizing can mitigate these overloads. Furthermore, since there is only one ColumbiaGrid member involved, these issues will be the responsibility of the affected parties and no study team is proposed.

<u>14. Olympic Peninsula Area</u>

Bonneville's Holcomb – Oxbow 115 kV line overloads for numerous outages in the two-year and five-year heavy summer cases. This is caused by a recent reduction of the line rating. A project to upgrade the line is in the ten-year heavy summer case and protective relaying is in place to open the line prior to the project completion. It is expected that the upgrade project will be done sooner due to the rating reduction.

<u>15. Orofino Area</u>

Outages of the Dworshak - Hatwai 500 kV line and the Hatwai 500/230 kV transformer in the heavy summer cases cause low voltages and overloads in the Orofino area. An existing RAS for these outages resolves these overloads.

New issues from the System Assessment

There are no new issues identified in the System Assessment.

Planning Process under PEFA/Order 1000

Functional Agreements

ColumbiaGrid's planning process, resulting in the development of a Biennial Transmission Expansion Plan, combines activities which comply with both the PEFA and Order 1000 Functional Agreement. This planning process includes additional Order 1000 activities that need to be included within the scope of ColumbiaGrid's annual System Assessment such as the identification and evaluation of Order 1000 Needs for transmission facilities driven by reliability requirements, economic considerations or public policy requirements. ColumbiaGrid's planning process also provides additional opportunity for interested persons to submit written suggestions to be considered as Order 1000 Potential Needs and discussed during a public meeting. In addition, Order 1000 requires ColumbiaGrid to re-evaluate, in each System Assessment, the most recent prior Biennial Transmission Expansion Plan to determine if changes in circumstances or other facts require evaluation of alternative transmission solutions which may include Order 1000 Projects in the Plan.

In this planning cycle, ColumbiaGrid hosted an Order 1000 Needs Meeting on February 11, 2016. This meeting was open to the public with an objective to discuss Order 1000 Potential Needs that should be included in the upcoming system assessment. Prior to this meeting, a meeting notice was sent to interested persons for collecting any suggestions on Order 1000 Potential Needs. Presentation materials and other documents for this meeting can be found on the ColumbiaGrid website at: https://www.columbiagrid.org/event-details.cfm?EventID=1047&fromcalendar=1.

In ColumbiaGrid's Planning Process, following the completion of the Order 1000 Needs Meeting, Order 1000 Potential Needs are vetted during the System Assessment to identify Order 1000 Needs. As part of the System Assessment, ColumbiaGrid performs applicable screening studies of the ColumbiaGrid Planning Region using the Order 1000 Planning Criteria and Needs Factors to identify Order 1000 Needs from the Order 1000 Potential Needs. The results of this evaluation process are documented in the 2016 System Assessment Report and Needs Statement documents that are developed as part of the ColumbiaGrid Planning Process. Figure C-1 outlines high-level components of ColumbiaGrid PEFA/Order 1000 Planning Process.

Order 1000 Potential Needs

In 2016, after the announcement of a new planning cycle and the opportunity to participate in ColumbiaGrid's Planning Process, several entities expressed their interests and submitted two study requests as Order 1000 Potential Needs. One of these Order 1000 Potential Need submittals requested ColumbiaGrid to assess a possible 600 MW capacity upgrade of the Pacific DC Intertie. The other submittal requested ColumbiaGrid to study the impacts associated with the replacement of certain generation assets (*i.e.,* Colstrip Units 1, 2, and 3) with a combination of intermittent renewable resource and/or gas turbine generation alternatives located in Montana.
Primarily, these submissions were intended to address the public policy requirements and potential transmission impacts associated with state compliance options under the U.S. Environmental Protection Agency's Clean Power Plan and California's 50% Renewable Portfolio Standards. However, ColumbiaGrid determined that neither of the

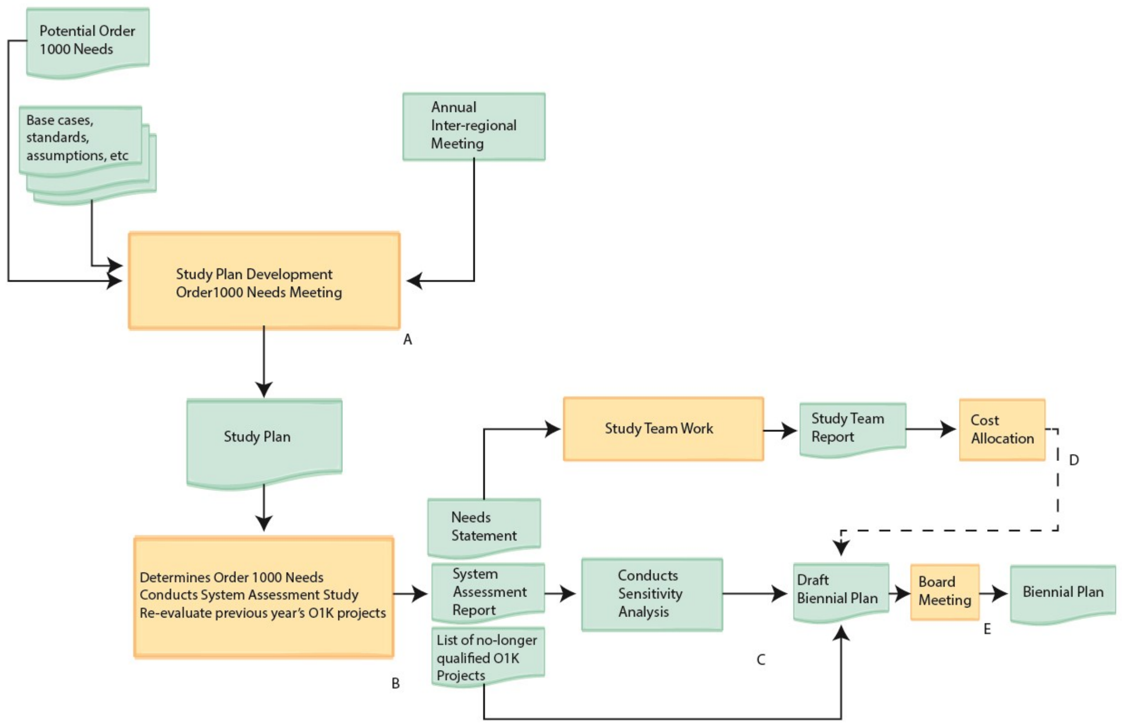


Figure D-1 Overview of ColumbiaGrid's Planning Process

two study requests described an Order 1000 Potential Need, which is an item that is proposed or considered for possible identification as a need for transmission facilities in the ColumbiaGrid Order 1000 Planning Region that are driven by reliability requirements, economic considerations or public policy requirements. Specifically, neither study request: (i) addressed any identified regional transmission reliability concerns in the ColumbiaGrid Planning Region; (ii) identified an economic concern relevant to a transmission need of any ColumbiaGrid Order 1000 Parties; or (iii) identified a potential transmission need driven by a Public Policy Requirement obligation of any ColumbiaGrid Order 1000 Parties. Currently, no ColumbiaGrid Order 1000 Parties are subject to the California 50% RPS or would have significant transmission reliability impacts resulting from replacement of coal-fired generation in Montana with similarly sighted renewable energy or gas-fired projects.

Consequently, no new Order 1000 Potential Needs were identified by ColumbiaGrid in this planning cycle so there was no need to perform any subsequent evaluation to identify Order 1000 Needs or issue Order 1000 Need Statements.

Interregional Transmission Projects

A proponent of an Interregional Transmission Project (ITP) may seek to have its ITP jointly evaluated by the Relevant Western Planning Regions by submitting the ITP into the regional transmission planning process of each Relevant Planning Region. ColumbiaGrid's Order 1000 Planning Process includes a submission window in which proponents may submit a proposed ITP into the ColumbiaGrid regional transmission planning process no later than March 31st of any even-numbered calendar year.

For each ITP that meets the submission requirements of the Order 1000 Common Tariff Language, ColumbiaGrid (if it is a Relevant Planning Region) will participate in a joint evaluation by the Relevant Planning Regions beginning in the calendar year of the ITP's submittal or the immediately following calendar year. In the ITP Joint Evaluation Process, ColumbiaGrid will confer with the other Relevant Planning Region(s) regarding ITP data and projected ITP costs, study assumptions and methodologies that will be used in evaluating the ITP through its regional transmission planning process.

This year, four proposed ITPs were submitted for joint evaluation by the Western Planning Regions. ColumbiaGrid was not identified as a Relevant Planning Region and did not receive any of these proposed ITP submittals into its regional transmission planning process. Therefore, ColumbiaGrid is not actively participating in the joint evaluation of any proposed ITP during the current 2016-2017 ITP evaluation cycle.

Reevaluation of Order 1000 Projects

ColumbiaGrid includes the re-evaluation of Order 1000 Projects from the most recent prior Plan within the scope of its annual System Assessment under the PEFA/Order 1000 Functional Agreements. This task requires ColumbiaGrid to re-evaluate the most recent Biennial Plan to determine if changes in circumstances require evaluation of alternative transmission solutions. Since there were no Order 1000 Projects included in the 2015 Biennial Plan or the 2016 Update to the 2015 Biennial Plan, there were no Order 1000 Projects from a prior Plan to be re-evaluated in this planning cycle.

Annual Interregional Coordination Meeting

ColumbiaGrid participates in an Annual Interregional Coordination Meeting with the other Western Planning Regions. The purpose of this stakeholder meeting is to discuss interregional topics which may include the following: Each Planning Region's most recent Annual Interregional Information, identification and preliminary discussion of interregional solutions, including conceptual solutions, that may meet regional transmission needs in each of two or more Planning Regions more efficiently or cost effectively; and updates of the status of ITPs being evaluated or previously included in ColumbiaGrid's regional transmission expansion plan.

ColumbiaGrid hosts the Annual Interregional Coordination Meeting in turn with the other Planning Regions, and will hold the next meeting on February 23, 2017 in Portland Oregon. Prior to the meeting, ColumbiaGrid will notify stakeholders by email regarding details of the upcoming Annual Interregional Coordination Meeting. ColumbiaGrid will also post details and agenda for the Annual Interregional Coordination Meeting on its web site at: https://www.columbiagrid.org/O1000Inter-overview.cfm

Study Team Updates

The following study teams have been active over the last year:

1. Puget Sound Area Study Team
2. Sensitivity Study for Long-term Alcoa Shutdown Study Team

In addition, interested parties also discussed potential reliability issues in Northern Mid-Columbia area which may result in a formation of new Study Team in the future. More details of these Study Teams and potential issues are provided below:

1. Puget Sound Area Study Team

Over the past decade, the transmission owners in the Puget Sound Area have been concerned about the ability of their transmission systems to economically and reliably serve area load, while simultaneously supporting power transfer commitments between the Northwest and British Columbia. The primary focus for the Puget Sound Area Study Team has been to address these concerns by developing a long-term transmission expansion plan for the Puget Sound Area.

Planning the transmission system in the Puget Sound Area is a complex undertaking. There are a large number of transmission facilities which means a high possibility of multiple outages of service transmission facilities for scheduled maintenance or for forced outages in actual system operation. As a result, the traditional transmission planning approach by assuming that all facilities are in service may not be reflective of such system operations. To address this concern, the study considered not only system performance following N-1 and N-2 contingencies with all lines in service, but also the system performance with a prior single element out of service. Many generators in the north Puget Sound Area affect the transmission capacity and flows in the Area. The study also used historical generation levels to approximate generation patterns. The study included the effects of ambient air temperature variations on thermal facility ratings. The information was gathered from studying the system response during multiple outage conditions. Such information provided valuable insight into system performance. It was used to determine transmission facility additions that would be required to minimize operating actions such as curtailing firm transfers or adjusting area generation when a facility is out of service. In October 2010, the Puget Sound Area Study Team issued a report on these results entitled, “Transmission Expansion Plan for the Puget Sound Area.” The portion of that report that addressed south-to-north transfer limitations was updated in October 2011.

The following six projects were identified as the most effective ways for correcting the major limitations of south-to-north transfers. They can significantly reduce the risk of curtailing firm transfers. These facilities are shown in Figure E-1.

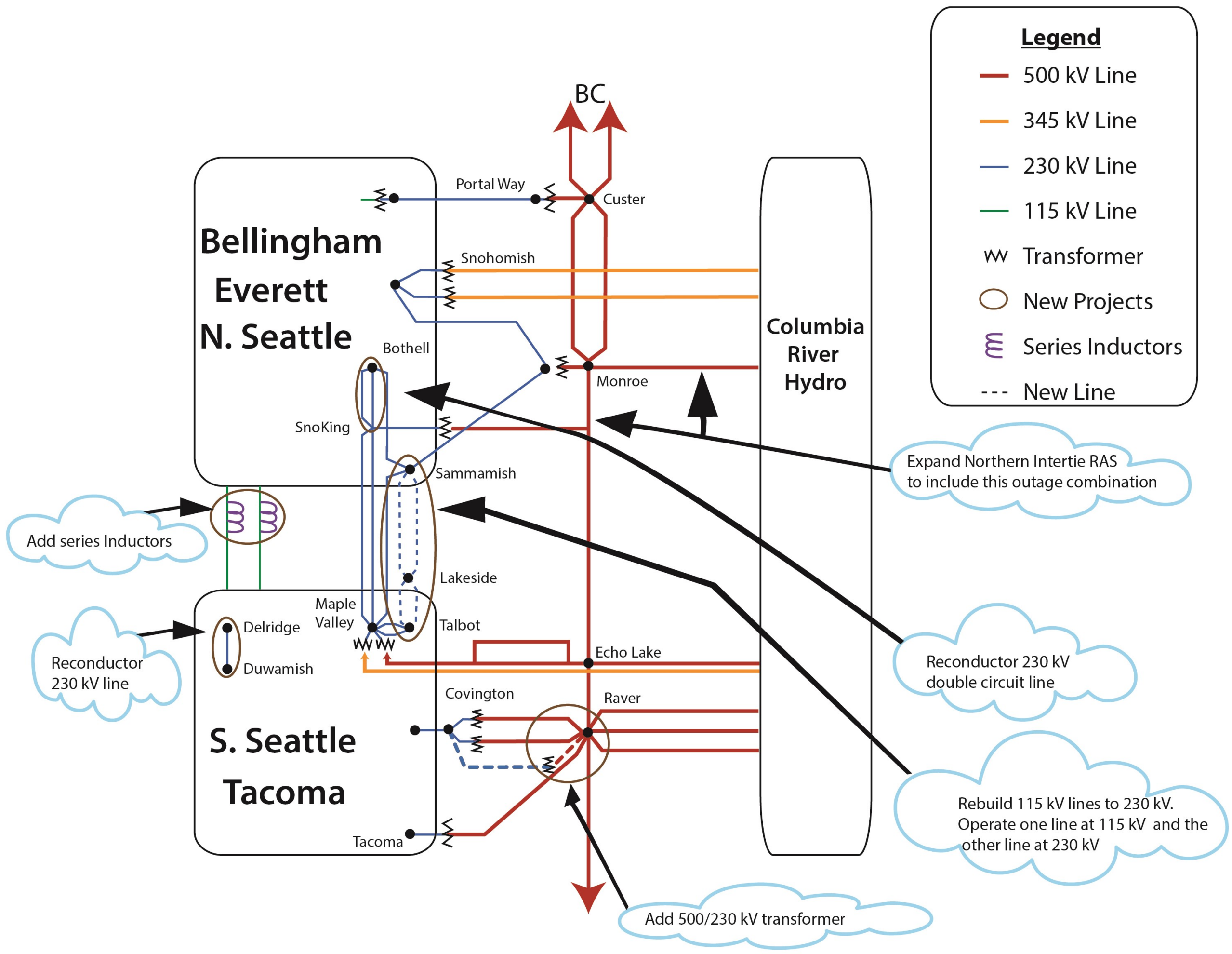


Figure E-1 Puget Sound Area

1. Reconductor the Bothell-SnoKing 230 kV double circuit line.
2. Add series inductors to the Massachusetts-Union-Broad and Broad-East Pine 115 kV underground cables.
3. Extend the Northern Intertie Remedial Action Scheme (RAS) for the combined loss of Monroe-SnoKing-Echo Lake and Chief Joseph-Monroe 500 kV lines.
4. Add a Raver 500/230 kV transformer and a 230 kV Raver–Covington line.

5. Upgrade both Sammamish-Lakeside-Talbot 115 kV lines to 230 kV. Energize one line at 230 kV and the other at 115 kV

6. Reconductor the Duwamish - Delridge 230 kV line.

The update to the north-to-south portion of the "Transmission Expansion Plan for the Puget Sound Area" completed in 2013. The following two projects were identified as the most effective way for correcting the major limitations found for north-to-south transfers.

1. Add a second Portal Way 230/115 kV transformer.

2. Upgrade Monroe –Novelty 230 kV line to operate at 80 degrees Celsius.

The Puget Sound Area Study Team continues to support the analysis of these projects by supporting deficiencies identified in System Assessments and a sensitivity to look at the switching of the series inductor project. All of the reports can be found on the ColumbiaGrid website http://www.columbiagrid.org/PSAST-overview.cfm.

2. Sensitivity Study for Long-term Alcoa Shutdown Study Team

In 2015, Alcoa curtailed production at its Alcoa Wenatchee Works plant due to unfavorable market conditions for some of Alcoa's aluminum products. At that time and presently, Alcoa has forecast its Wenatchee Works to return to operation in spring 2017.

The loss of the Alcoa load has impacted electrical transmission and generation operations in the immediate area, including operations at Chelan PUD's Rock Island hydroelectric project and McKenzie switchyard and BPA's Valhalla substation, which includes a tie to the Douglas PUD system.

To mitigate the impact from Alcoa plant shutdown, temporary procedures have been developed to separate Chelan PUD's McKenzie switchyard from BPA's Valhalla substation during these impacting conditions. Chelan PUD has also developed emergency ratings for its outgoing facilities from McKenzie.

At the same time of implementing the above temporary mitigation procedure, Chelan PUD is proposing that a long term plan should be developed to address potential issues from system operation and planning point of view in case that the Alcoa plant will not come back in 2017 as predicted. Such a long term plan needs to be discussed and evaluated with joint study efforts from neighboring systems.

ColumbiaGrid created a study team for sensitivity study for Long-term Alcoa shutdown in December 2016. The study team includes representatives from Chelan PUD, BPA, Douglas PUD, Grant PUD and Avista. The purpose of this study team is to evaluate potential alternatives to these temporary mitigation procedures. These alternatives could potentially include additional emergency ratings, re-conductoring existing facilities, construction of new facilities, or the use of special protection schemes. The kickoff meeting was held at ColumbiaGrid's office on December 9th, 2016.

Information on this study team is located on the Team page at http://columbiagrid.org/planning-expansion-overview.cfm .

Potential reliability issues on Northern Mid-Columbia

In 2015, Grant County PUD observed that the generating units at Wanapum Dam were consistently absorbing reactive power during most loading conditions. To solve the issue, Grant PUD requested a joint study effort to investigate the operating voltage schedule for the automatic voltage regulation at both Wanapum and Priest Rapids dams as well as coordinating local system conditions with BPA.

On May 1st, 2015, representatives from Grant PUD, Chelan PUD, BPA, Puget Sound Energy, PacifiCorp and Douglas PUD had a meeting in Puget Sound Energy's offices in Bellevue, WA. Grant PUD presented the discovery and team members discussed about the possible scenarios and phenomena associated with the generation operating conditions in this area. Participants believed that more data needed to be collected and evaluated to verify the potential causes of the problem.

In November 2015 an announcement was made to idle the Intalco and Wenatchee primary aluminum smelters plants in the area. This resulted in a significant change in system conditions, in particular, the loading condition in Mid-Columbia area. With a substantial drop of load due to the smelter retirements, the reactive generation pattern is expected to be changed for Wanapum units, as well. The joint study efforts are therefore put on hold for further data collection.

Sensitivity Studies for 2016

The following sensitivities that were proposed for analysis in 2016 are described below:

1. N-1-1 Outage Study

In previous years' System Assessments, N-1-1 outage studies (loss of the first element, followed by system readjustment and then compounded by loss of the second element) have been done for all branches with voltage level above 100 kV. There was interest in expanding the study to include non-branch combinations described in NERC standards. This sensitivity study is intended to support the NERC standards that require N-1-1 contingencies (TPL-003-0b and TPL-001-4 category P3 & P6) and also simulation of N-1-1 scenarios without manual system adjustments between contingencies (PRC-023).

Present analysis tools are not capable of processing the extremely large number of N-1-1 contingency scenarios. This sensitivity studied pared down the list of contingencies using two different methods to create a manageable list. The first method was to use a tool to evaluate the severity of the N-1-1 contingencies, based on branch flow relationships indicated by the utilization of linear analysis such as distribution factors. A branch flow relationship tool was developed to essentially exclude N-1-1 branch contingency combinations that do not result in a more severe outage condition than the outage of either single branch by itself. This tool was designed to work for a large subset of the branch contingencies but does not work with some of the branch contingencies and none of the non-branch contingencies. In order to pare down the remaining contingency list the second method was used. This method only created an N-1-1 combination if the first contingency resulted in increasing the loading on another element to 80% of its limit. These methods were used to reduce the list of N-1-1 contingencies to approximately 2.6 million contingencies per studied case.

Two cases, the 2026 heavy summer and the 2027 heavy winter, were studied. Each contingency list was run and processed to identify N-1-1 combinations that resulted in 1) a more severe overload than the N-1 outages by themselves or 2) if both N-1 outages solved on their own and the combination of the two outages did not. At this stage, voltage issues are not tracked by assuming adequate voltage support adjustments after the first contingency. A breakdown of the results can be found in Table F-1 below.

	New Unsolved Contingencies	New and Increased Overloads
2025 Heavy Summer	535	78,490
2026 Heavy Winter	14,181	22,197

Table F-1 N-1-1Outage Results Summary

The detailed outage results were made available to all planning participants.

2. Five-Year Extra Heavy Winter Study

NERC Reliability Standards require that the transmission system is planned for expected peak load conditions. The cases studied in the System Assessment have loads based on a probability of 50 percent not to exceed the target load. To account for the possibility that this level is exceeded due to accelerated growth or extreme conditions, this sensitivity developed and studied an extra heavy winter case.

The five-year heavy winter case was selected for the study and the loads classified as adjustable in the Northwest area of the case were scaled up to achieve a 10% increase of load for the entire area. Transfers to California were adjusted to account for the increase. This new case was studied with the same assumptions and methodology used for the System Assessment. The contingency results were compared to quantify the effect of the load increase and the detailed outage results were made available to all planning participants but it is up to each member to decide how to use this information. A summary of the study results can be found in the table F-2 below.

	New Overloads	**Increased Overloads**	**New Unsolved Contingencies**
2022 Heavy Winter	90	58	28

Table F-2 Extra Heavy Winter Outage Results Summary

3. Credible Multiple Contingency Evaluation

Operational and planning study work is usually done independently. There is a concern that there may be gaps between what both groups are looking at. This sensitivity was intended to evaluate the contingencies performed in operational studies to identify any credible multiple contingencies that are not captured in the planning study work. These contingencies would be applied to the near term heavy summer and winter cases and the results would be provided to the members. The goal was to provide information to facilitate a discussion on if a gap exists and if there should be any changes to the planning process.

During the process of developing a study plan for this sensitivity, several changes to the operational planning process were being looked at. It was determined that the proposed changes could have a large impact on the results of this sensitivity. In order to avoid the possibility of performing invalid study work it was determined that this sensitivity should be postponed and reevaluated after the changes to the operational planning process are implemented. This is likely to occur in 2017.

4. High Renewable Study

Future renewable generation requirements will lead to large increases of renewable generation across the west and lower usage of fuel based generation. This sensitivity evaluates the long term system impacts in the Northwest due to high renewable generation across the west.

This study started with an evaluation of high renewable production data in the Northwest to determine desired system conditions. It was determined that a spring day at approximately 4:00 p.m. with minimal exports to California was the most likely scenario for high renewable production in the Northwest with non-peaking load levels. This system condition was compared to the economic planning study output to find an ideal system condition for this sensitivity study. The selected system profile was exported from the economic planning study model and incorporated into the long term heavy summer case to create the base for the study work. There was some difficulty in managing the bus voltages in the case due to the number of fixed output reactive devices near the wind generation. The System Assessment contingency list was run to evaluate the system performance.

Overall fewer overloads and unsolved outages were found which is primarily attributed to the reduced stress from the load profile. Some new overloads and unsolved outages were found in the area of wind generating units and are being looked at to determine if the voltage control issues attributed to the new issues.

The detailed outage results were made available to all planning participants for their review at:

http://www.columbiagrid.org/SAsensitivities-overview.cfm

5. Case Error Evaluation

Three errors were discovered in the System Assessment cases that the members determined may affect the results of the System Assessment. The first error was a topology error in the 2017 HW at Wanapum substation caused by a bug in the software, the second was a missing bus tie breaker on the 230 kV bus at Covington substation in the 1018 light spring, both five year heavy, and the long term heavy summer cases, and the third error was an incorrect generation dropping model in all of the cases.

These corrections were made and the cases were restudied. The contingency results were compared to quantify the effect of the corrections and the detailed outage results were made available to all planning participants. The long term results were further evaluated to identify reportable changes from the System Assessment. None of the newly identified or corrected issues were reportable as multi member issues.

As a result of the case errors identified changes to the case development and study process are being implemented in the next study cycle to avoid similar issues. A summary of the study results can be found in the table F-3 on the next page.

	New Overloads	Corrected Overloads	Increased Overloads	Reduced Overloads
2026 Heavy Summer	7	11	0	13
2026 Heavy Winter	1	6	11	0

Table F-3 Case Error Evaluation Summary

The detailed outage results were made available to all planning participants at:

http://www.columbiagrid.org/SAsensitivities-overview.cfm

Transient Stability Study

Transient stability study evaluates system dynamics for a short period of time, normally within 60 seconds, to ascertain whether a system can return back to a steady state condition following the clearance of the disturbance. The major contributor to the transient dynamics is generators' acceleration or deceleration force at their rotor shaft due to a sudden change, with a disturbance added or cleared, to power system demand and supply in the system. Many other factors can also contribute to the transient dynamics of a disturbed power system. These factors include the switching (in or out) of shunt devices, set points controlling the HVDC power controller, aerodynamics impact to wind turbine generation, ramping up and down of loads, switching action from protection relays, etc.. Various types of dynamic behaviors from equipment may affect and respond to each other simultaneously as they are all interconnected through a transmission network. Therefore, a transient stability study will need to evaluate the system performance with all transmission network and power system devices modeled. Upon the clearance of a disturbance, the system may evolve into a transient process finally becoming stable and well damped or becoming unstable and poorly damped. The NERC TPL-001-4 standard classifies the type (P0-P7) of normal faults based on the involvement of different types of equipment and consequential actions. It also specifies their stable performance requirements. Performing dynamic simulation is the most widely adopted way to check and verify whether a fault event satisfies the compliance requirements outlined in NERC standard.

Transient stability studies require detailed dynamic modeling of all types of power system devices, including generators, speed governors, excitation systems, power system stabilizers, wind turbines, solar panels, loads, HVDC's, FACTS, switching devices, relays, etc. Each dynamic model was designed to reflect the mechanical or electrical characteristics of the physical devices and their control logic. Efforts have been taken to accurately develop models and validate their performance. Those efforts include standard manufacturer tests before commissioning, parameter tuning when commissioned, and later stage model validation and calibration when they are in production. Every year, utilities provide updates of their device models to WECC, and WECC uses this information to compile transient stability base cases for the western interconnection system.

Since 2015, transient stability study has been performed by ColumbiaGrid as a part of system assessment for all members and participants. In general, the scope of this study included; 1) Base case Development, 2)Data Validation, 3) Contingency Submission, 4) Performing Transient Stability Study, and 5) Interpreting Study results.

In 2015, 44 contingencies submitted by all 8 ColumbiaGrid members, PacifiCorp and Portland General Electric were studied using a 2016-2017 heavy winter case initially prepared by WECC. Base case data was reviewed and adjusted to fix model errors that would have prevent transient stability simulations from producing accurate results. ColumbiaGrid adopted PowerWorld as the primary tool for transient stability simulation.

In 2016, the scope of the transient stability study has been significantly expanded. It includes 6,394 contingencies submitted by 11 utilities (8 ColumbiaGrid members, PacifiCorp, Portland General Electric and BC Hydro). The majority of the utilities provided a complete list of their transient stability contingencies covering both TPL and severe fault events on all their major substations, equipment and voltage levels. Moreover, the transient stability base cases were developed by ColumbiaGrid independently by incorporating the latest model information from WECC and members. These two base cases are 2021-2022 heavy summer case and 2017-2018 heavy winter case. The base case data was created, reviewed and adjusted to fix modeling errors and provided to all members on the ColumbiaGrid website.

ColumbiaGrid Transient Stability Study Process

The 2016 transient stability study process was started with the April 2016 planning meeting. During the meeting, ColumbiaGrid members and participants discussed the study assumptions including; base case selection, contingency submission, time line etc. It was decided that in this year and years after, ColumbiaGrid should independently develop transient stability base case using the power flow base case used in system assessment and latest dynamic models from WECC base case library. Also in 2016, all utilities and participants could submit any amount of contingencies for the study. In the August and October planning meetings, study results for both 2021-2022 heavy summer case and 2017-2018 heavy winter case were discussed respectively. Transient stability issues have been discussed in details in a closed session for members only.

Study Methodology

For this year's assessment, 6,394 contingencies were submitted by all ColumbiaGrid members and 3 participants (PacifiCorp, Portland General Electric and BC Hydro). Among all the submissions, Avista, Puget Sound Energy, Snohomish County PUD, Grant PUD, Tacoma Power and Portland General Electric provided their complete list of contingencies. All other utilities provided a selected list of contingencies. All contingencies submitted cover a variety of disturbance types such as normal and extreme contingencies; TPL and CIP-14 contingencies; 3 phase fault and single line to ground fault; normal clearing, delayed clearing or reclosing on each utility's 115kV, 230kV and 500kV system.

For each of the 6,394 contingency simulations 23 major generation facilities in both the Northwest region and neighboring systems, and 16 major 230kV and 500kV buses were monitored for instability. The generation facilities included major nuclear, coal, gas and hydro units with rated capabilities greater than 100 MW and during each simulation the real power output, reactive power output, mechanical power, rotor speed, rotor angle, terminal voltage, field voltage, and field current were monitored. The buses were used to monitor for issues with voltages, frequency and interface MW flows. A detailed list of the contingencies used and the monitored elements can be found in Attachment C.

In order to prepare both base cases for transient stability simulations, the base cased was reviewed and tested with a sequence of standard simulations. The base case preparation process is performed in several teps. In each step, modeling issues identified as potential errors were verified and erroneous parameters were fixed.

The first several steps of data review and correction was performed with the master dynamic data library from WECC. The master dynamic data library is the collection of the most up-to-date transient stability models submitted by all WECC utilities. This library is under constant change when utilities perform model validations and update the model. Newly added devices will also be included to reflect most up to date system conditions. Due to the fact of the large amount of renewable resources being added to California and other regions, the WECC dynamic data library has expanded quickly in recent years and a lot of data errors have been introduced. Moreover, several utilities using different software platforms for transient stability simulation, often submit data in incompatible formats. Correction to the library model data is the first step to make sure the data used is accurate.
The second step is the initial power flow and stability data review. It is a review process based on the understanding of the system operating condition and with the help of the embedded validation tool of PowerWorld. In this stage, PowerWorld automatically checked the values of some model parameters against their commonly known limits. It also automatically alters time constants of model internal blocks to avoid potential numerical problems caused by the integration algorithm the software used. Such an automatic validation tool provides a first layer of model parameter verification against some apparent errors.

The third step of data review was based on the limit violation report generated during the initialization of the simulation. When the dynamic simulation is initialized, internal variables to each stability model will be calculated backwards from the terminal power flow conditions. During the process of initialization, these internal variables will be checked against their limits enforced by the model parameters. A violation of the limits may imply either errors of model parameters, or the mismatch between dynamic and power flow setups. Each of these violations is reviewed and verified against the common mechanical or electrical characteristics of the devices. Potential errors are identified and further simulation and model tests are performed to help to correct these errors.

As the fourth step of data correction, several standard tests including no fault flat run, Chief Joseph braking test and Double Palo Verde fault are simulated. Each simulation results were carefully reviewed to identify potential data issues, which were fixed based on the discussion with modeling engineers in owner utilities and common knowledge of the devices or their control logics.

The last step of data correction is based on the screening simulation of key contingencies based on previous experience. Several contingencies resulting in unexpected dynamic behaviors were reviewed. Discussion between ColumbiaGrid and related utility members to address these concerns were documented, and if there was any correction of parameters, they are added back to the data base and simulation was re-run based on the new information.

Simulation results

The simulated results have been included in the Attachment C. The amount of contingency in each type is listed in the following table:

Member	P1	P2	P3	P4	P5	P6	P7	Extreme	BUS	Load	Total
Chelan	5							3			**8**
Avista	333	61		314	41		22	334	128		**1233**
PSE	571			90			7		108		**776**
SCL	1			4			2	11			**18**
Snohomish	173	86	109	41	67		29				**505**
Tacoma	83	11	1470	82	13	1974	12				**3645**
Grant	55	20		45	13		1			4	**138**
BPA				2				7			**9**
PGE	15	16				18	2	5			**56**
PacifiCorp	3										**3**
BC Hydro	3										**3**
	1242	**194**	**1579**	**578**	**134**	**1992**	**75**	**360**	**236**	**4**	**6394**

Table G-1 Wind and Solar Installation in WECC

Among all 6,394 contingencies, both 2021-2022 heavy summer case and 2017-2018 heavy winter case showed similar stability or instability results, with only two exceptions. There is one P1 contingency was not stable in 2021 heavy summer case. After identifying the issues, ColumbiaGrid contact the utilities and it was confirmed to be caused by an error modeling of a retired generator. Also, in 2021 heavy summer case an extreme (3 phase fault P4) contingency become stable due to the system enhancement in that area. Other than these two contingencies, all contingencies that are stable (or not stable) maintain their status in both cases.

For both cases, ColumbiaGrid study shows that there were 2 P1, 3 P4 and 43 Extreme Contingencies becoming unstable (inducing oscillation without positive damping). With the confirmation of the utilities, the unstable P1 and P4 contingencies were due to the missing modeling of associated RAS or protection devices. With the protection devices or RAS incorporated in the simulation, the generators that induced oscillation will be tripped by out of step relay shortly after the fault events, and the rest of the system will restore stability. Under NERC TPL-001-4 requirements, after adding the protection model, these contingencies meet the NERC compliance.

In summary, ColumbiaGrid confirmed that all simulated contingencies submitted by members and participants satisfy the NERC TPL-001-4 requirement for both cases we studied.

Colstrip Tripping due to ATR

Similar to the observation in 2015, more than 20 contingencies simulated resulted in generation tripping at Colstrip units in Montana due to the protection from an Acceleration Trend Relay (ATR), confirmed by Northwestern Energy. The tripping was mainly caused by two types of fault events:

1. Fault at load center with long clearing time.

2. Fault at the main transmission path serving west coast load center.

In the first type, faults was normally applied during peaking condition at the load center, for example, Seattle area. During the fault, load has been drastically reduced due to the low voltage in the surrounding area. This creates an excessive amount of unbalance between the supply and demand. Even though the load center can be far away from the Colstrip units, a long clearing time guarantees the supply/demand unbalance has enough time to propagate to the Montana area and stretch the generator acceleration relays, leading to the eventual tripping of the unit. It has been observed, as load is the key factor for tripping in this type of event, composite load models are sensitive to the tripping action. It is therefore worth evaluating in further depth, the accuracy of the composite load model in the Northwest region and its relationship with generation protections.

In the second type, the clearing of a fault of a primary 230kV or 500kV transmission path will suddenly interrupt a significant amount of power being sent from Montana to west coast in a peaking condition. This sudden drop of load will rapidly increase the acceleration of Colstrip units and lead to tripping. Unlike the first type, such a scenario will normally happen in a relatively short period of time (normally less than 10 cycles) and independent of load models.

In 2022, two smaller units at the Colstrip plant are proposed to be retired. It is important that we continue investigate the scenarios of Colstrip tripping as many contributing factors will be changed thereafter. These factors include: Generation during peak conditions, interface flow, plant inertia, and new replacement generation sources.

Economic Planning Study

Economic Planning Study (EPS) has been part of ColumbiaGrid's study program since 2013. This type of study focuses on evaluating potential future system performance with the ability to simulate hourly market behavior using Production Cost Software. This type of analysis is intended to simulate the operation of Day-ahead or hour-ahead markets. This section summarizes this study that was conducted by ColumbiaGrid in 2016.

Understanding a Production Cost Model:

Utilities commit and dispatch their supply to economically serve their load and contractual obligations. A production cost model attempts to mimic this behavior by economically committing and dispatching supply to serve the entire modeled load. This is equivalent to a single owner dispatch which is different from how the market is operated in the real world. For example, when modeling the entire Western Interconnection (WECC) which consists of thirty-eight Balancing Areas, the models will try to serve all areas with the objective to minimize the costs for the entire WECC footprint. However, in reality, each individual Balancing Area (BA) will attempt to re-balance its supply and demand in order to minimize its net costs. With this apparent difference, modeling constraints need to be applied such that the model could mimic historic operating behavior.

Data Set for ColumbiaGrid study:

For the 2016 EPS study, ColumbiaGrid's production cost data set was based on the WECC 2026 Common Case v1.30 as the starting point. Generally, the study process begins with the review of the data set to then follow by conducting a backcast study to ensure that simulation results can reasonably mimic historical data. However, time constraints did not allow ColumbiaGrid to perform a full backcast this year. Rather, the lessons learned from previous backcast study results were applied to the WECC 2026 Common Case. Below are some observations or key changes made to the starting data set to create the ColumbiaGrid data set.

By comparing the WECC 2026 Common Case with the previous data set (WECC 2024 Common Case), the following are key differences:

- Additional coal retirement at Centralia 2, Colstrip 1 and 2.
- Behind The Meter (BTM) PV in California has increased from 7,642 MW to 12,120 MW. This accounts for 86% of the increase in solar in California.
- Behind The Meter PV outside of California has increased from 1,240 MW to 4,063 MW.
- Net modeled wind/solar in the California Balancing Area changed to 8,240/24,710 MW (32,950 MW total).
- Net modeled wind/solar in WECC changed to 29,590/33,600 MW (63,190 MW total).

- Net amount of wind/solar increased by 11,185 MW with 79% of it located in California.
- California load forecast is lower in 2026 Common Case

In addition, the following major changes were applied to the WECC 2026 Common Case:

- Applied updates developed by NTTG for WECC 2026 Common Case v1.30. This is part of the coordination efforts with the other western planning regions to share and exchange planning data.
- Corrected unusual monthly peak demand and/or load shapes to align with historic shapes.
- Corrected annual California peak demand and load to properly account for behind the meter PV. The CEC load forecast includes the impact of BTM-PV. BTM-PV is modeled as an independent supply therefore its impact on the annual forecast is added to the CEC forecast to create the modeled loads.
- The dataset over states BTM-PV in California by 1,700 MW. This was correct with values provided by the CEC.
- A production cost model uses net generation for power plants. The imported power flow data that represents the transmission system includes station service load. To align the modeled net generation in the PCM, station service load was deleted in the PCM.
- Dispatchable Hydro in California historically peaks during the daily load peak. However, currently most of the dispatchable Hydro in California is modeled as a fixed hourly shape. The daily summer peak load typically occurs mid-day. Taking into account the 24,710 MW of solar in the California Balancing Area the net load minus solar shifts the peak to late afternoon/evening. The modeling of dispatchable Hydro in California was changed from an hourly shape to proportional load following (PLF). PLF was changed to look at native load minus solar generation. This change results in a more appropriate Hydro dispatch in California and reduces the need to cycle thermal units mid-day.
- Non-Dispatchable Supply: Non-dispatchable supply is not limited to only wind and solar. There are other types of supplies (geothermal, cogeneration, and biomass) for which commit and dispatch behavior is not dependent on the wholesale electric market. The model for these types of supply was changed from dispatchable to non-dispatchable based on historic average operation by month.
- Modeling of combined cycle units was changed from net plant to an equivalent 1x1 configuration, (i.e. by gas turbine plus proportional share of steam turbine). This allows additional operational flexibility in meeting daily loads considering combined cycle has a high minimum loading.

- Commitment order: Initial runs resulted with combined cycles outside of California cycling daily in response to the net California load (load minus solar). They would turn off mid-morning and start late afternoon. The modeling of combined cycles was changed to lower this behavior for units not dedicated to California market.

- California AB32 created a default CO_2 import fee equivalent to an 8.06 heat rate burning NG. It also allows low emission suppliers to register with the State to receive a lower CO_2 cost when importing power into California. This is called Asset Controlled Supply (ACS), currently three entities are registered as ACS: Bonneville Power Administration, Powerex, and Tacoma Power. To represent this potential sale to California the modeling was changed from a flat monthly profile to an hourly profile based on select BPA Hydro projects plus Columbia Generating Station minus BPA load.

- California entities have approximately 3,000 MW of contracted wind supply in the Northwest. These projects are exempt from the California CO_2 cost and can be imported without a CO_2 cost. Due to the high CO_2 cost, it is assumed 50% of the contracted wind is scheduled to California without an import fee.

- Modeling of the Hydro projects on the Columbia River was changed to Proportional Load Following only. Hydro-Thermal Coordination was previously used on select plants but the resulting daily operation did not conform to historic daily shapes.

  ⇒ Note: Additional work is needed to understand the operational flexibility of the projects on the Columbia River and its ability to respond to a changing Western market.

- Hydro generation on the Columbia River is based on 2008.

- Set maintenance schedules for Northwest supply to correspond to the spring run-off

- Set maintenance schedules for select supply outside of the Northwest to correspond to regional needs. For example: Maintenance for select California supply was changed to correspond to peak renewable generation in California (Mar, Apr, and May)

- Corrected definitions for several WECC Paths

Impact of Energy Imbalance Market (EIM)

This issue of potential impacts from EIM in the day-ahead market was discussed multiple times during the course of this study. From the study results, participants in the Energy Imbalance Market (EIM) currently have no impact on a day-ahead production cost model run. EIM rules require each participant to supply a day-ahead forecast of contracted supply to meet hourly load. This is the same for all Balancing Areas. The value of an EIM is in optimizing intra-hour operation which is outside the scope of this analysis.

Sensitivity Run

The Northwest Power & Conservation Council has identified a resource need in the Northwest after the retirement of three coal units. This evaluation retires five coal units with three scenarios containing different assumptions on replacement capacity. Given renewable supply is primarily an energy source and the WECC dataset currently meets state RPS standards, the focus shifts to needed dispatchable supply, Therefore, this analysis assumed the replacement capacity to be Combined Cycle technology. However, it is critical to note that this assumption is based on pure speculation regarding locations and types of additional resources and it does not represent ColumbiaGrid's position or prediction regarding future resources in the Northwest. There are a variety of dispatchable supply options available and it is up to local utility resource planning and applicable regulatory agencies to determine the type, capacity and location of supply to be procured. This analysis focused on three sensitivity cases with various amounts of new dispatchable supply at locations that did not impact the current transmission system.

The cases that were used in this year study is shown below:

- Case R0: Replacement Capacity zero: Assumes no replacement capacity is installed in the Northwest (Retire 2,540 MW with the addition of no new supply).

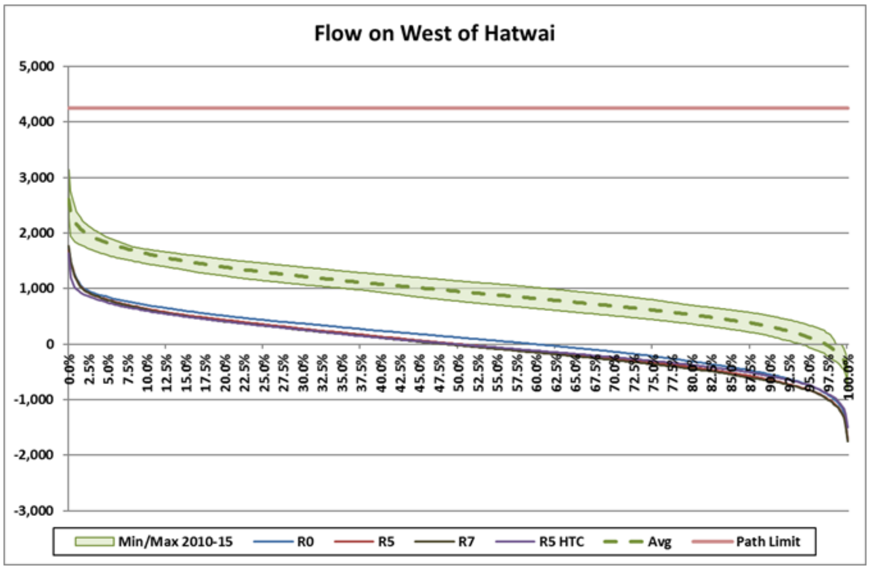
- Case R5: Replacement Capacity from five new combined cycle units with duct firing: Assumes five 1x1 combined cycle units are installed in the Northwest: Carty II plus four combined cycles located at Centralia (Retire 2,540 MW with the addition of 1,940 MW new supply).

- Case R7: Replacement Capacity from seven new combined cycles with duct firing: Assumes seven 1x1 combined cycles are installed in the Northwest: Carty II plus three combined cycles located at Centralia, one north of Seattle and two at McNary (Retire 2,540 MW with the addition of 2,660 MW new supply).

Study Results

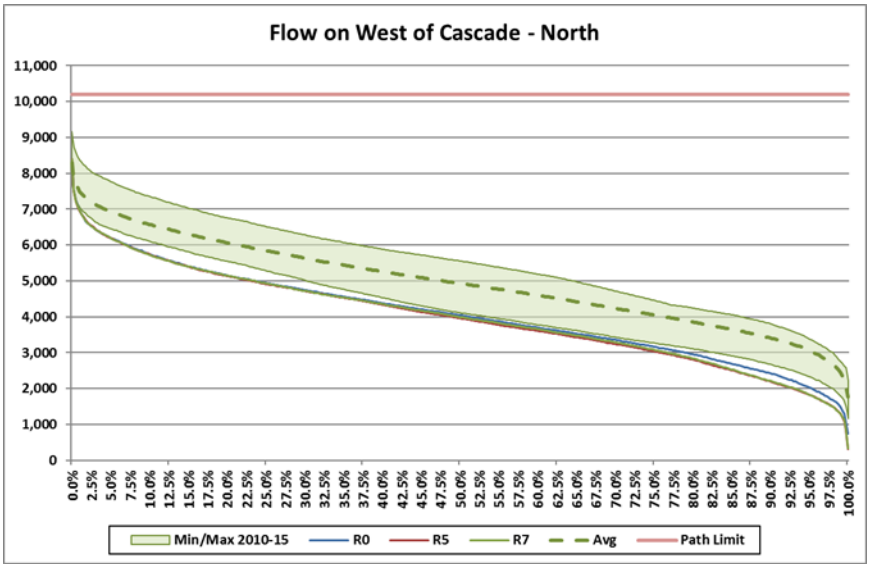
Resulting Impact on Northwest Flows

Figure H-1 Flowgate: West of Hatwai



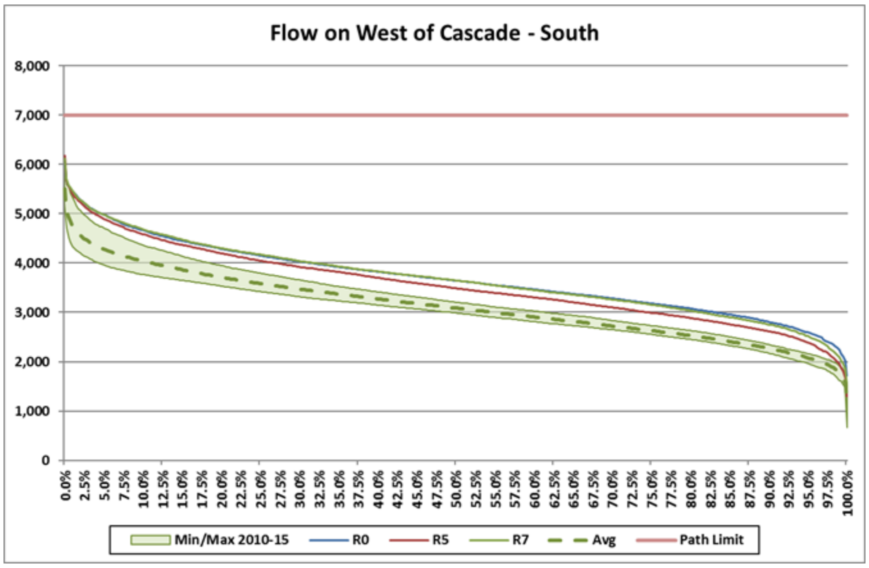
The retirement of Colstrip 1 and 2, 614 MW of Steam Coal results in Figure H-2

Figure H-2 Flowgate: West of Cascades – North



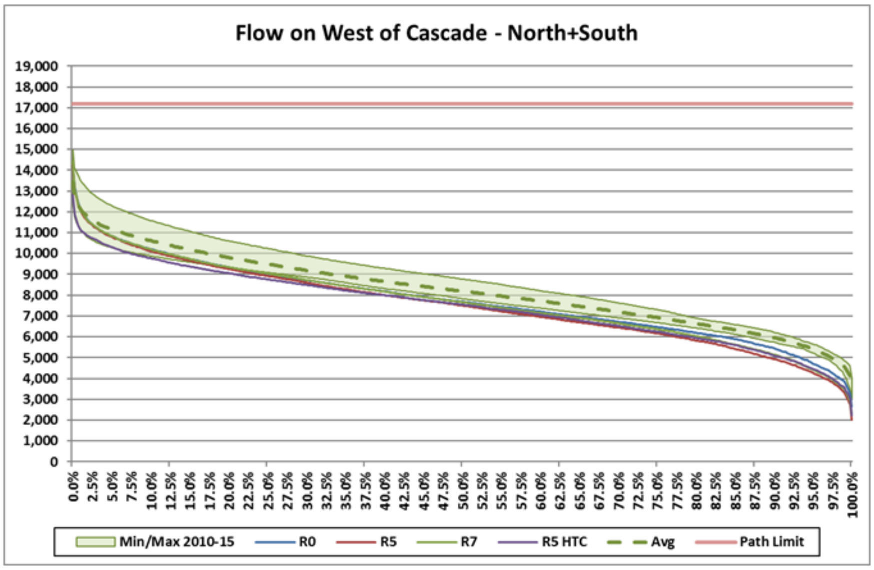
Flow on West of Cascades North drops an average -940 MW which is on the low side of historic operation. Peak flow is 70 MW higher than average historic peak flow but within the historic operating range.

Figure H-3 Flowgate: West of Cascades - South



Flow on West of Cascades South is up an average of 515 MW which is above historic operating range. Peak flow is 610 MW higher than the average historic peak flow and above the historic operating range.

Figure H-4 Flowgate: Net West of Cascades – North and South

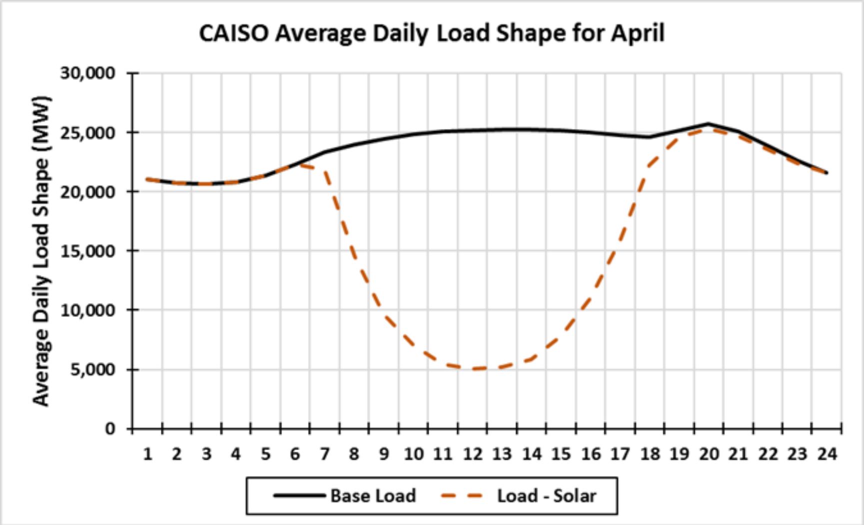


Net flow on West of Cascades North and South is down an average of 570 MW placing flow on the low side of historic operation. This is a little higher than historic generation from Colstrip 1 and 2 (455 MW). Peak flow is 880 MW higher than average historic peak flow but within the historic range.

California Duck Curve

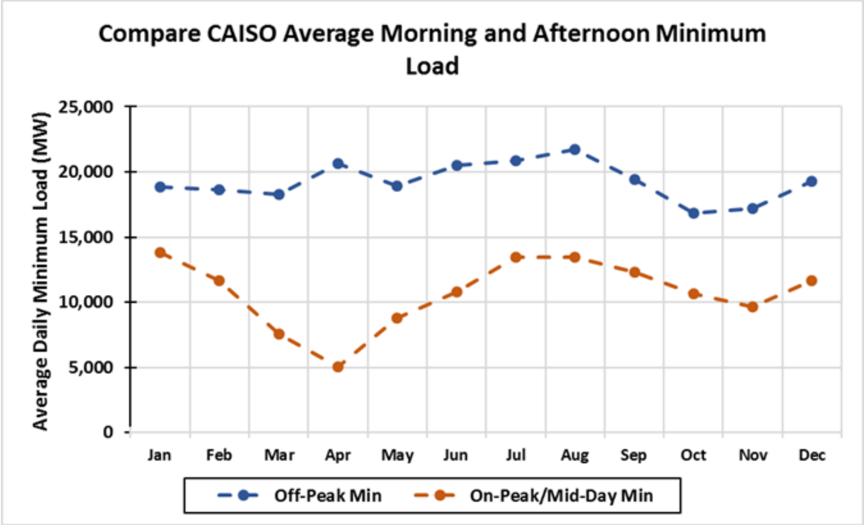
To understand flows on the interties to California, an understanding of the impact that solar PV resources have on observed CAISO load is necessary. This is commonly called the duck curve. The duck curve shows how the observed California load is changing by switching the daily minimum load from traditional Off-Peak hours to On-Peak as seen in the following chart.

Figure H-5 California Duck Curve for April



The following chart shows the average monthly minimum load for both Off-Peak and On-Peak.

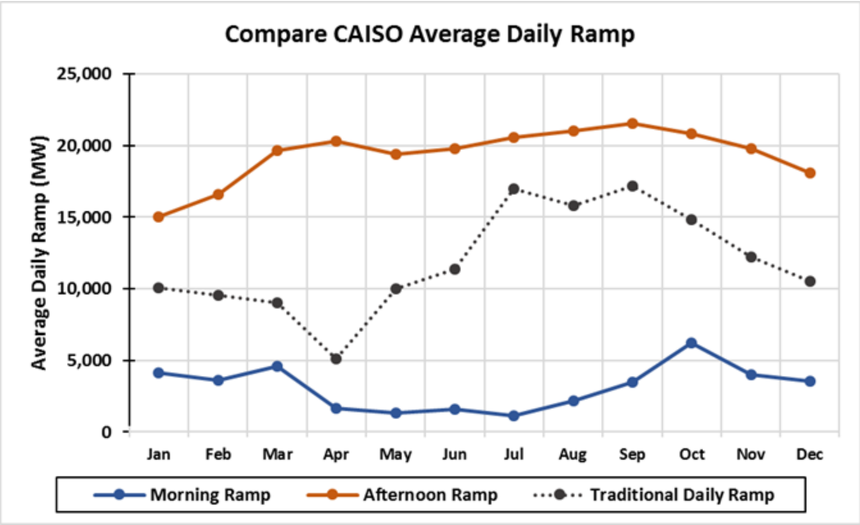
Figure H-6 Average Morning & Afternoon Minimum Load



The Mid-Day minimum is typically 55% of the traditional Off-Peak minimum. Given low load and high solar during April the On-Peak minimum is 25% of the Off-Peak minimum.

The winter peak remains unchanged but the summer peak shifts from mid-day to late afternoon/evening. A mid-day minimum followed by the daily peak results in a significant increase in daily ramp as seen in the following chart:

Figure H-7 Average Daily Ramp Comparison

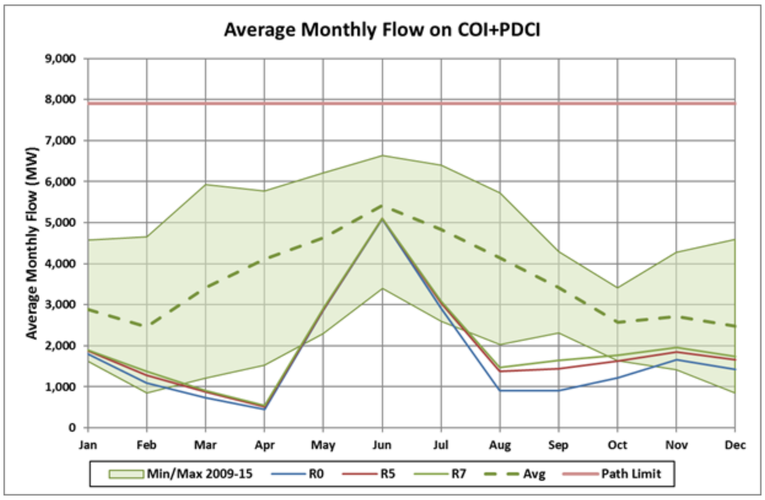


Flow to California

The average reduction in flow from historical values to the scenario cases is 1,675 MW. Assuming solar is at a 20% load factor (LF) is equivalent to 8,400 MW of new solar which is on par to the increase in modeled solar in California. Net modeled solar in California is 24,711 MW

In normal Hydro Case R5 and R7 show a slight increase in flow to California over R0 byr 12% and 16%.

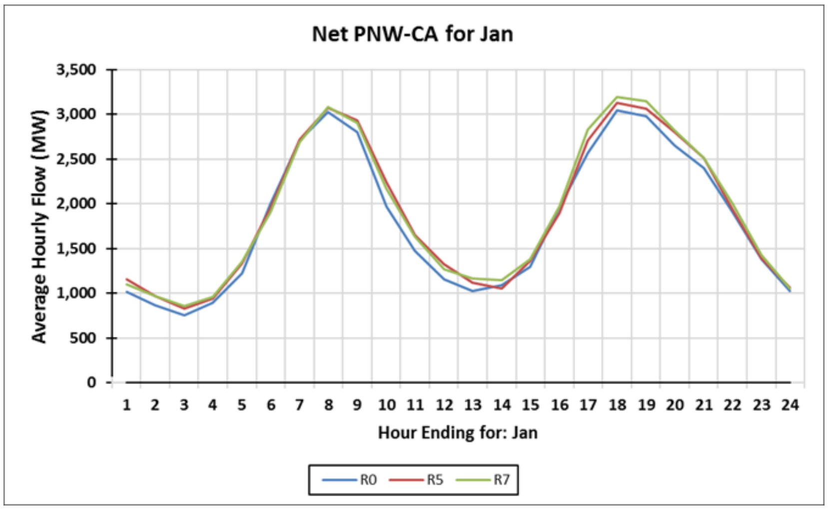
Figure H-8 Average Monthly Flow on COI+PDCI



Switching to average monthly flow to California, on COI+PDCI, is on the low side are below historic operating range except for peak flow during the spring run-off (June).

The increased Northwest supply in Cases R5 and R7 results in a minor increase in flows to California, the average by quarter is: 160, 40, 435 and 325 MW.

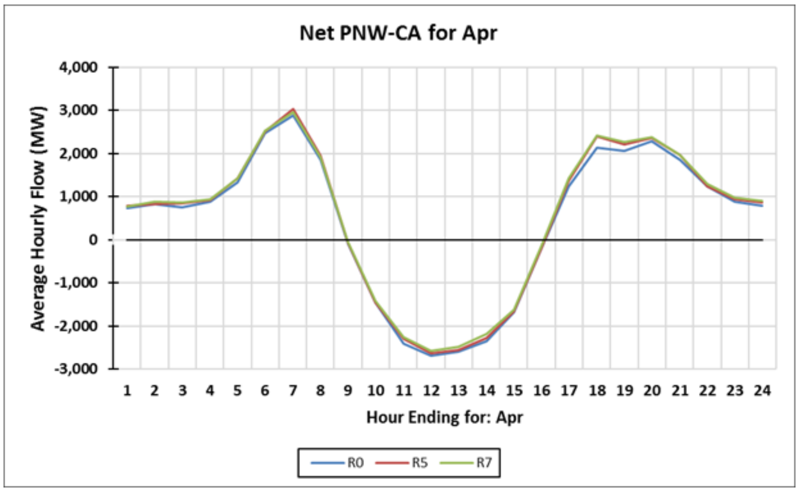
Figure H-9 Compare Average Hourly flows for January



The 24,710 MW of forecasted solar in California resulted in a net load with a significate mid-day dip in load, i.e. the Duck Curve. This translates into a mid-day dip in export to California. In January, the the mid-day flow is on par with the off-peak flow.

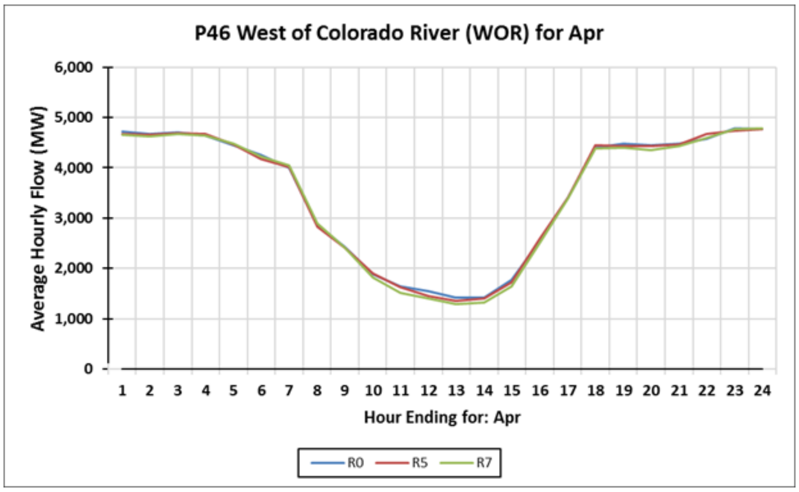
The study results showed a morning ramp of 2,250 MW and an afternoon ramp of 2,050 MW. This is a significant shift from a historical 16 hour On-Peak block sale.

Figure H-10 Compare hourly flows for April



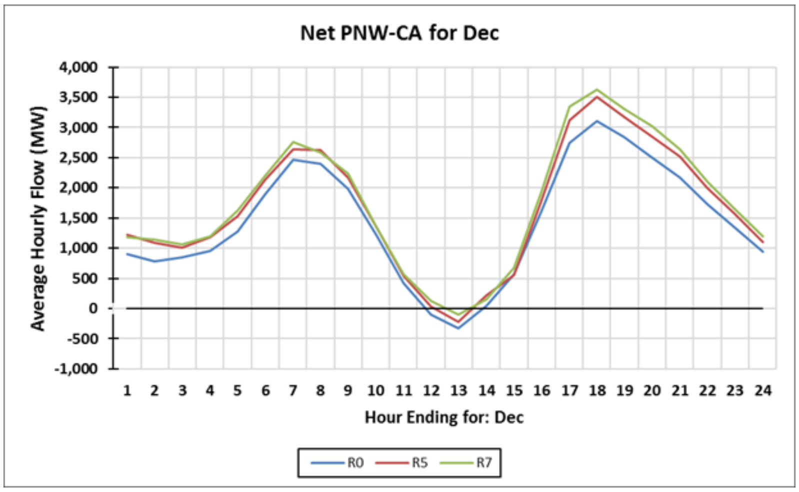
Some months we may expect Intra-day bi-directional flows. In April, there is little spread between the three sensitivity cases. You can also expect low loads and high solar generation in California resulting in minimum observed load for the year. This causes a large intra-day evening ramp of 4,760 MW.

Figure H-11 P46 West of Colorado River for April



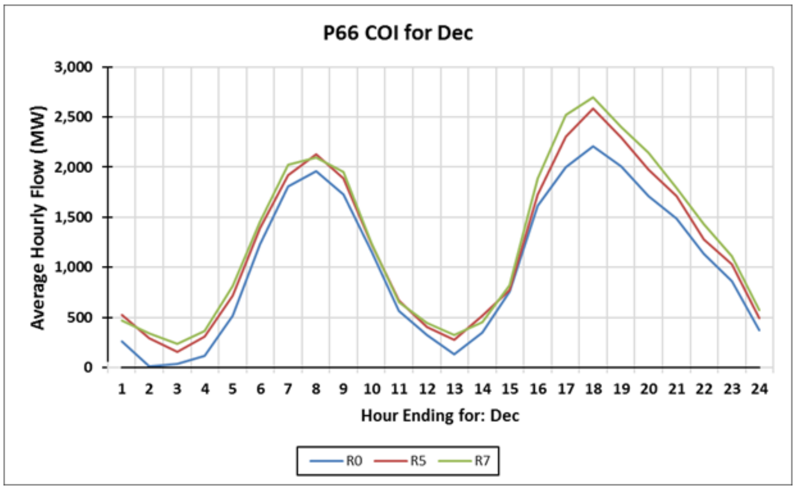
This swing in flow to California can be seen on Path 46 West of River into California with an evening ramp of 3,060 MW. Note the intra-day change in flow where the average Off-Peak flow is greater than On-Peak flow.

Figure H-12 Compare hourly flows for December



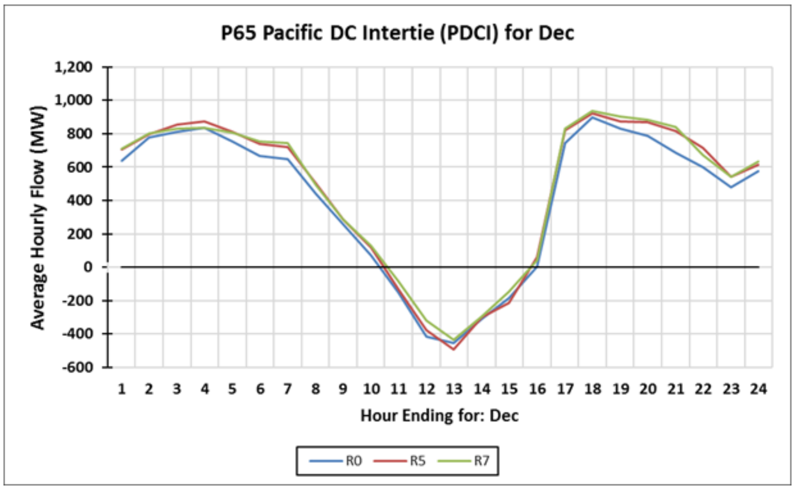
In December, the net flow to California is slightly negative mid-day at HE 13. Note that the off-peak flow is lower than the mid-day flow. Cases R5 and R7 have a minor impact on increasing flow.

Figure H-13 P66 COI for December



What is interesting is the flow on the individual paths. On COI, the average flow is positive with a clear morning and evening ramp. Off-Peak flow is slightly lower than Mid-Day flow and the evening ramp is higher than the morning ramp.

Figure H-14 P65 Pacific DC Interties (PDCI) for December

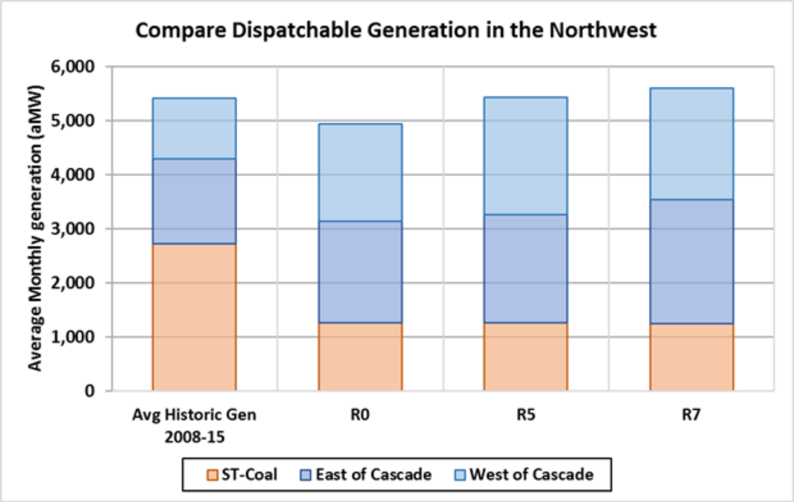


The pattern change on PDCI intertie with a mono dip in flow. At the apex of the dip we see 5 hours of imports with relative stable flows during the off-peak and shoulder hours.

These study results predict a new pattern of intertie flows where we see simultaneous imports on the PDCI and exports on the COI during the same hour.

Northwest Dispatchable Generation
A significant reduction in flow to California is observed but Northwest dispatchable generation remains constant. This can be seen in the following chart.

Figure H-15 Dispatchable Generation in Northwest Comparison



In Case R0, existing supply increases generation by 1,000 MW to replace the 1,460 MW lost coal generation. This increase in natural gas generation in Case R0 reduces the Northwest's flexibility in meeting a dry or critical water year.

Running the cases with dry and critical water year hydro assumptions would yield insights into how the different scenario cases support Northwest resource needs.

Conclusions

As a result of state RPS goals in California, high levels of solar PV penetration at both the household (BTM) and utility scale levels will change how the Western energy market works. The EPS study results showed the observed minimum load in California shifts from traditional Off-Peak to On-Peak (Mid-Day). This results in significant increase in the daily ramp which occurs during the On-Peak time period. The traditional time period will likely change from two to four (o'clock?), the On-Peak will be split into three products: Morning Ramp, Mid-Day, and Evening Ramp. Traditional on-peak/off-peak flow will no longer exist.

This change in California will impact intra-day flow in the rest of WECC. For example, the results show that 3,000 MW of exports from California mid-day would likely be followed by 3,000 MW of imports during the evening is plausible. This significant flow fluctuation would likely impact power flow patterns for the entire WECC.

Uncertainty surrounding the flexibility of Columbia River generation to respond to the changing western market still exists. Traditional operation of the Columbia is set up for a sixteen hour on-peak block which may not provide sufficient flexibility to respond to the predicted power swings.

Traditional wholesale power markets currently do not support daily unit commitment except during peak time in summer. To support the interregional power swings predicted by this study, either the clearing price goes up to support daily cycling of units or California will have to contract with supply to meet this need.

Additional modeling work is needed to reduce the the cycling of units outside of California. This will likely reduce the daily swing of power to California.

System Assessment Study Assumptions

The Northwest transmission grid is interconnected and, as a result, it was necessary for all major transmission system operators and planners in the Northwest to participate in the development of this Expansion Plan, whether or not they are parties to the ColumbiaGrid PEFA. Major transmission owners in the Northwest were notified individually and encouraged to participate in the planning process. All participants who provided input to the study or helped to screen results had access to the same information whether or not they were parties to PEFA.

The major assumptions that form the basis of the System Assessment are loads, generation, external path flows, and planned transmission additions. These assumptions were used to develop the cases that were studied in the System Assessment. The approach used for developing each of these assumptions is summarized below.

Load Modeling Assumptions

As required in the NERC Reliability Standards, the transmission system is planned for expected peak load conditions. Normal summer and winter peak loads were based on a probability of 50 percent not to exceed the target load. The loads in light load cases were to reflect typical loads in the target timeframe.

As modeled in the base cases, the total winter peak load for the Northwest system is forecasted to be 30,613 MW in the two-year case (this is down from the 30,855 MW modeled in last year's case), 31,462 MW in the five-year case (this is down from the 32,973 MW in the five-year case in last year's System Assessment), and 32,572 MW in the ten-year case (this is down from the 33,066 MW in the ten-year case in last year's System Assessment). The forecasted summer peak load is 25,011 MW in the two-year case (this is down from the 25,120 MW modeled in last year's case),, 25,835 MW in the five-year case (this is down from the 25,892 MW modeled in last year's case), and 27,115 MW in the ten-year case (this is down from the 27,390 MW modeled in last year's case). The two-year light spring case includes 17,907 MW of load in the Northwest.

Although the Northwest system as a whole peaks in the winter, summer peak conditions require similar attention. The capacity of electrical equipment is often limited by high temperatures, which means the equipment has lower capacity in summer than in winter. As a result, a lower summer load could be more limiting than a higher winter load due to the impact of ambient temperature differences on equipment ratings.

Resource Modeling Assumptions

Resource additions ten years into the future are much more difficult to forecast than loads. Although numerous potential generating projects have been planned and developed in various stages, uncertainty that comes from a variety of reasons can eventually prevent them from going into service. Resource assumptions are particularly important due to the fact that, depending upon their location, resources can either conceal existing transmission problems or create new ones.

Similar to last year's System Assessment, this year's Assessment modeled the firm transfer commitments from area generators. A variety of feasible dispatches within these firm commitment levels could impact the transmission system. The WECC base cases do not model these firm commitments. To study the cases with feasible dispatches, the planning participants agreed that the System Assessment base cases would be built from the generation dispatch modeled in each WECC base case. Changes were made to selected external paths to obtain desired firm commitment levels, serve expected load forecasts, and reflect known generation retirements.

While the existing Northwest resources are adequate to meet summer loads, they are insufficient to meet projected winter peak loads and firm transfer commitments. Northwest utilities rely on seasonal diversity with other regions to meet winter load obligations by importing from California and the Southwest. For this reason, imports into the Northwest from California were used to meet the shortfall of new resource additions in the Northwest for the winter cases. However, there are many indicators, such as the number of requests for interconnection that transmission providers have received, to suggest if other resources will be developed in the region during this ten-year planning horizon. The addition of proposed generation projects, especially thermal projects on the west side of the Cascades, could have a significant impact on the performance of the transmission system and reduce the reliance on California imports. Planned transmission projects will be reviewed periodically to determine whether changes in resource additions will impact the need for, or scope of, these projects.

Two generation retirements were included in this assessment. First, the state of Washington has come to an agreement with the owner of the Centralia Power Plant that a 700 MW coal-fired unit will be retired in 2020 and will be followed by the retirement of the second unit in 2025. In order to match the system conditions, the five-year base cases were studied with one unit on and the ten-year cases were studied with both units off (the transmission impacts of the retirement of both units were studied in 2011 and this study report is posted on the ColumbiaGrid website). Second, the state of Oregon has reached an agreement with Portland General Electric to retire the Boardman Coal Power Plant in 2020. Portland General Electric plans to replace a portion of the coal generation with a 325 MW gas-fired Carty generation project adjacent to Boardman. The Boardman retirement was modeled in the ten-year cases and the Carty generation project was modeled in all of the cases.

There are several thousand MWs of wind generation capacity in the Northwest, however, none of these resources are dispatched during peak load conditions in the System Assessment. Historical operation has shown that there is often little wind generation during either winter or summer peak load conditions, and it is not relied on to meet firm load obligations. Operation without wind generation results in increased reliance on local gas generation and/or increased imports from California and the Southwest. However, it is also important to note that fast development of intermittent (variable) resources and policies in California and the Southwest may impact this assumption since they could significantly affect how the system is planned and operated.

The two–year light spring base case used this year was modeled to represent the condition with significant wind generation in operation. Each wind generator was modeled to represent 35% of capacity. This is a typical operational scenario since the output from wind generation is usually at the highest level during off peak conditions and it could pose some reliability issues. This case will be used to investigate transmission problems that may occur for this type of condition.
A list of all the resources used in the base cases is included in Attachment A.

Transmission Modeling Assumptions

As required by the NERC Reliability Standards and PEFA, it was necessary to model firm transmission service commitments in the System Assessment. PEFA requires that plans be developed to address any projected inability of the PEFA planning parties' systems to serve the existing long term firm transmission service commitments during the planning horizon, consistent with the planning criteria. The NERC Reliability Standards do not allow any loss of demand or curtailed firm transfers for single element contingencies that are not radial, and allow only planned and controlled loss of demand or curtailment of firm transfers for multiple element contingencies.

The ColumbiaGrid planning process assumes that all ColumbiaGrid members' transmission service and native load customer obligations represented in WECC and ColumbiaGrid base cases are firm, unless specifically identified otherwise (such as interruptible loads).

Of the external paths, the British Columbia-Northwest and the two California Interties are most crucial during peak load conditions. These paths are bi-directional and are often stressed differently during winter and summer conditions. The flow patterns on Montana-Northwest and Idaho-Northwest paths are also different since they are typically stressed more during off-peak load conditions and are less critical during peak load conditions.

Conversely, the transmission paths internal to the Northwest are not scheduled. The flows on internal paths depend on factors such as flows on the external paths, internal resource dispatch, internal load level, and the transmission facilities that are in service.

During the winter, returning the firm Canadian Entitlement to British Columbia is the predominant stress on the Puget Sound area and the British Columbia-Northwest path. The California interties were used to balance the load and generation modeled in the studies. This resulted in moderate imports in the five-year and ten-year heavy winter cases which are not uncommon in reality.

In the summer, transfers on the British Columbia-Northwest and California interties are typically in the opposite direction. Surplus power from Canada and the Northwest are often sent south to California and the Southwest.

The path flows in the assessment were controlled within their limits. The West of Hatwai flows are quite low in this case as expected, given the fact that this path typically experiences stress only during off-peak conditions.

The loads, generation and path flows in the System Assessment are shown in Table H-1. The background for the specific existing firm transmission service commitments on members' paths that were modeled in the Transmission Expansion Plan are as follows:

	18HS	17-18HW	18LSP	21HS	21-22HW	26HS	26-27HW
Northwest Load	25,011	30,613	17,907	25,835	31,462	27,115	32,572
Northwest Generation	29,702	35,283	25,260	31,033	35,984	30,317	34,953
Northwest - BC Hydro Flow	-2,297	1,502	1,248	-2,298	1,503	-2,301	1,500
Idaho - Northwest Flow	-459	103	580	62	277	-16	396
Montana - Northwest Flow	618	1,160	1,127	670	950	756	909
PDCI Flow	2,000	1,230	3,102	2,711	1140	1,240	193
COI Flow	3,953	2,032	3,728	3,557	1497	3,247	428
North of John Day Flow	4,785	2,686	4,715	5,245	2,673	6,992	3,735
South of Allston Flow	2,135	1,112	1,033	1,508	702	1,289	498
West of Cascades North Flow	3,295	8,367	4715	4,389	8,810	4,968	8,999
West of Cascades South Flow	4,172	5,660	3,303	4,089	5,854	4,904	6,604
West of Hatwai Flow	173	460	1,924	457	571	588	319

Table I-1 Base Case Summary

Base Case Summary

1. Canada to Northwest Path

The capacity of this path in the north to south direction is 2,850 MW on the west side and 400 MW on the east side. The combined total transfer capability cannot exceed 3,150 MW. The total capacity of the path in the south to north direction is 3,000 MW, with a limit of 400 MW on the east side and a limit of 2750 MW on the westside. Both of these directional flows can impact the system ability to serve loads in the Puget Sound area.

The Canadian Entitlement return is the predominant south to north commitment on this path and is critical during winter conditions. Although the total amount of commitment varies, 1,350 MW of firm transmission service commitments are projected for the ten-year studies. Puget Sound Energy also has a 200 MW share at full transfer capability into British Columbia, which translates to a 130 MW allocation at the 1,350 MW level. Bonneville has committed to maintaining this pro-rata share of the Northern Intertie above its firm transmission service commitments. Both of these firm transmission service commitments are on the west side of the path, thus 1,500 MW of transfers are modeled in the south to north direction in heavy winter cases.

With reduced loads in the Puget Sound area in the summer, the return of the Canadian Entitlement is typically not a problem. The most significant stressed condition in the summer is north to south flows of Canadian resources to meet loads south of the border.

Powerex has long term firm rights for 242 MW for their Skagit contract, plus 193 MW to Big Eddy and 450 MW to John Day, for a total of 885 MW in the north to south direction. Powerex also owns 200 MW of transmission rights for the Cherry Point Project which is just south of the Canadian border and can be reassigned to the border. Puget Sound Energy has long term firm contracts for 150 MW and Snohomish has firm contracts for 100 MW. The total of all of these contracts is 1,335 MW.

The Puget Sound Area Study Team has been planning the system in the Puget Sound area to maintain 1,500 MW in the north to south direction to cover these firm transfers. Bonneville is making commitments to increase the firm transactions to 2,300 MW through the Network Open Season that will show up in the five-year time frame. 200 MW of this new commitment is planned to be scheduled on the east side of the Northern Intertie at Nelway. Therefore, the heavy summer cases will model 2,300 MW to cover the additional commitments that are being made on the Northern Intertie including the 200 MW on the east side at Nelway.

2. Montana to Northwest Path

This path is rated at 2,200 MW east to west and 1,350 MW west to east. The predominant flow direction is east to west. The path can only reach its east to west rating during light load conditions. Imports into Montana usually only occur when the Colstrip Power Plant facilities are out of service.

The firm commitments on this path exceed 1,400 MW east to west. There are also some counter-schedules that reduce the actual flows on the system. For the two-year studies, flow was modeled as 1,160 MW in winter and 618 MW in summer. The five–year studies modeled the flow at 950 MW in winter and 670 in summer. The ten–year studies modeled the flow at 909 MW in winter and 756 in summer.

3. Northwest to California/Nevada Path

The combined California Oregon Intertie (COI) and Pacific DC Intertie (PDCI) are rated at 7,900 MW in the north to south direction, although the combined operating limit can be lower due to the North of John Day nomogram. The COI is individually rated at 4,800 MW and the PDCI is rated at 3,100 MW. The ability to use COI up to its maximum rating is dependent upon remedial action schemes (RAS) both in the Northwest and California. The 300 MW Alturas tie from Southern Oregon into Nevada utilizes a portion of the 4,800 MW COI capacity. In the south to north direction, the COI is rated at 3,675 MW and the PDCI is rated at 3,100 MW.

Bonneville has upgraded these paths to potentially use these paths at their full capability. With the upgrades, the long term firm transmission service commitments on these paths are increasing to total about 7,700 MW. To investigate the stress that results from these commitments, these two interties were loaded close to their combined limit of 7,900 MW in the summer cases for System Assessment.

Bonneville is also planning a major equipment replacement at the Celilo terminal of the PDCI to replace aging equipment. These replacements are planned for 2017, at which time the rating of the PDCI will increase from 3,100 MW to 3,220 MW.

There are some firm transmission service commitments on this path in the south to north direction but not a significant amount. Non-firm sales are relied on by many parties in the winter, especially during very cold weather, when there are insufficient resources within the Northwest to meet the load level. For the base cases, Northwest resources were dispatched first, and firm transmission service commitments were modeled on external paths. Additional resources needed to meet the remaining load obligations in the Northwest were imported from the south, split between the COI and PDCI.

In the two-year heavy winter base case, the exports into California totaled 6,262 MW with 2,032 MW on the COI and 1,230 MW on the PDCI. Conditions with exports to California during peak Northwest winter load are typical of late winter conditions when more hydro is available in the northwest. The five-year peak winter case has a total of 2,637 MW export on the combined COI and PDCI paths while the ten-year heavy case has 621 MW export on the combined interties. The combined exports in the peak summer cases were modeled at about 5,953 MW in the two-year case, 6,268 in the five-year case, and 4,487 in the ten-year case. The two-year light load case has 6,830 MW export on the two interties.

4. Idaho to Northwest Path

The Idaho to Northwest path is rated at 2,400 MW east to west and 1,200 MW west to east. This path has about 350 MW of firm schedules into Idaho to meet firm transfer loads, in addition to a 100 MW point-to-point service contract. Summer conditions with flows at these levels are typical as there are few surplus resources to export from the east. In the winter, these transfer loads are reduced and PacifiCorp typically exports its east side resources into the Northwest to meet its west side load obligations. Due to the nature of the flows from Idaho, they are not expected to cause significant system problems in the Northwest during peak load periods. With the addition of the Hemingway-Boardman project, the rating of this path will increase by 1000 MW in the east to west direction and 1,050 MW west to east.

For the two-year cases, power is flowing at 103 MW into the Northwest in the winter and 459 MW into Idaho in the summer. The five-year winter case has 277 MW flowing into the Northwest. In summer, 62 MW was modeled flowing into the Northwest. The ten-year summer case had 16 MW flowing into Idaho and 396 MW into the Northwest in the winter case. The two-year light load case had 580 MW flowing into the Northwest from Idaho.

5. West of Hatwai Path

The West of Hatwai path is rated at 4,277 MW in the east to west direction but it is not a scheduled path. This path is stressed most during light load conditions when eastern loads are down and the excess resources from the east flow into Washington. This path is loaded to 460 MW in the summer and 173 MW in winter in the two-year cases. In the five-year cases, the path is loaded to 457 MW in the summer and 571 MW in winter. In the ten-year cases, the path is loaded to 588 MW in the summer and 319 MW in winter. The two-year light load case had 1,924 MW flowing on the path.

6. West of Cascades North and South Paths

The West of Cascades North path is rated at 10,200 MW and the West of Cascades South path is rated at 7,200 MW, both in the east to west direction. These paths are not scheduled paths but transfer east side resources to the west side loads. These paths are most stressed during winter load conditions, especially when west side generation is low. The north path summer loading was 3,295 MW in the two-year case, 4,389 MW in the five-year, and 4,968 MW in the ten-year cases. The winter loading was 8,367 MW in the two-year, 8,810 MW in the five-year, and 8,999 MW in the ten-year cases. The south path summer loading was 4,172 MW in the two-year case, 4,089 MW in the five-year, and 4,904 MW in the ten-year cases. The winter loading was 5,660 MW in the two-year, 5,854 MW in the five-year, and 6,604 MW in the ten-year cases. In the two-year light load case, the north path is loaded to

4,715 MW and the south path is loaded to 3,303 MW.

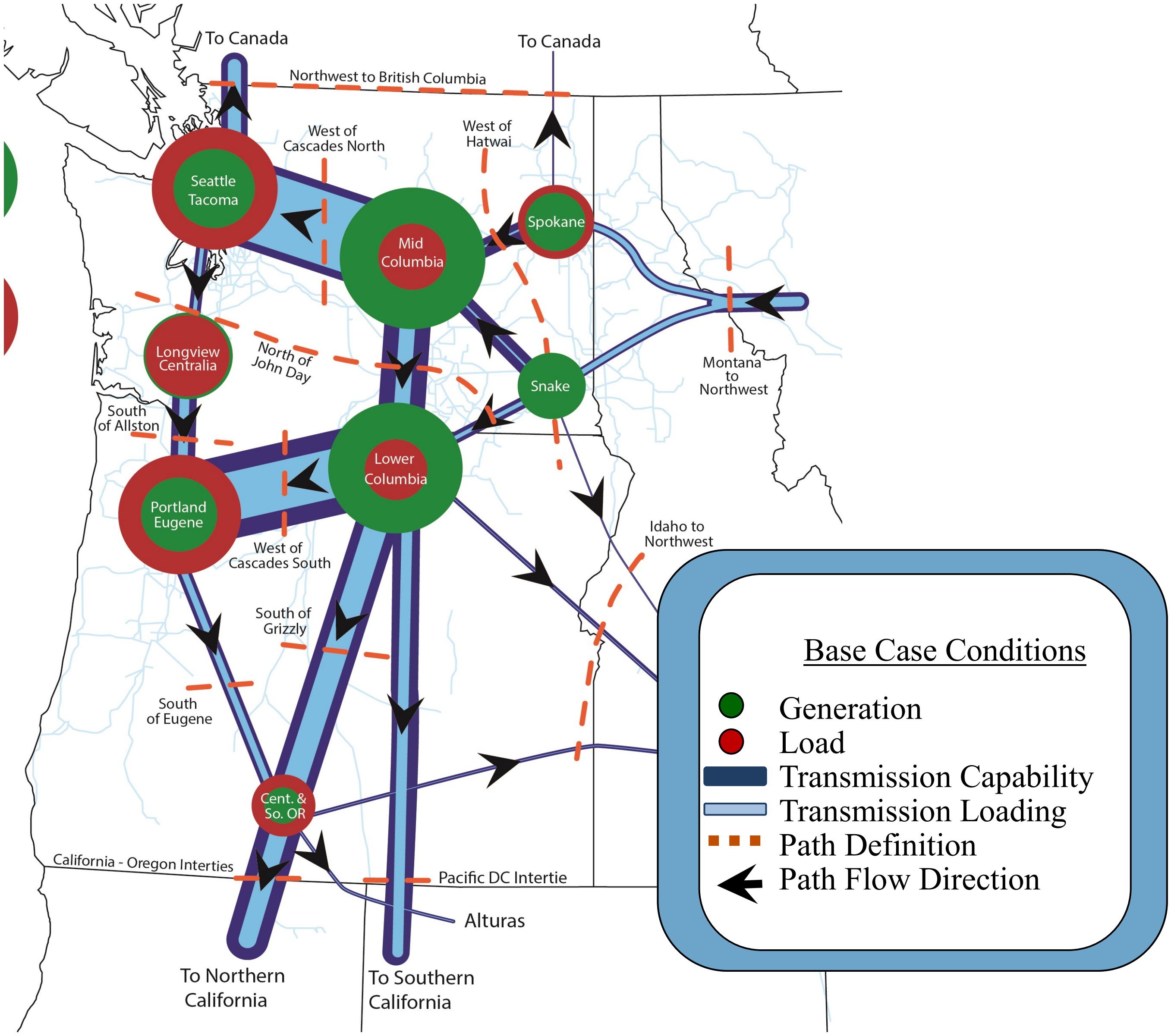


Figure I-1 Flows Modeled for One-Year Heavy Winter Peak Conditions

Flow Diagrams

The loads, generation and flows modeled in the base cases are shown in Figures I-1 through I-7. The Seattle-Tacoma area includes the area west of the cascades from the Canadian border south through Tacoma. The

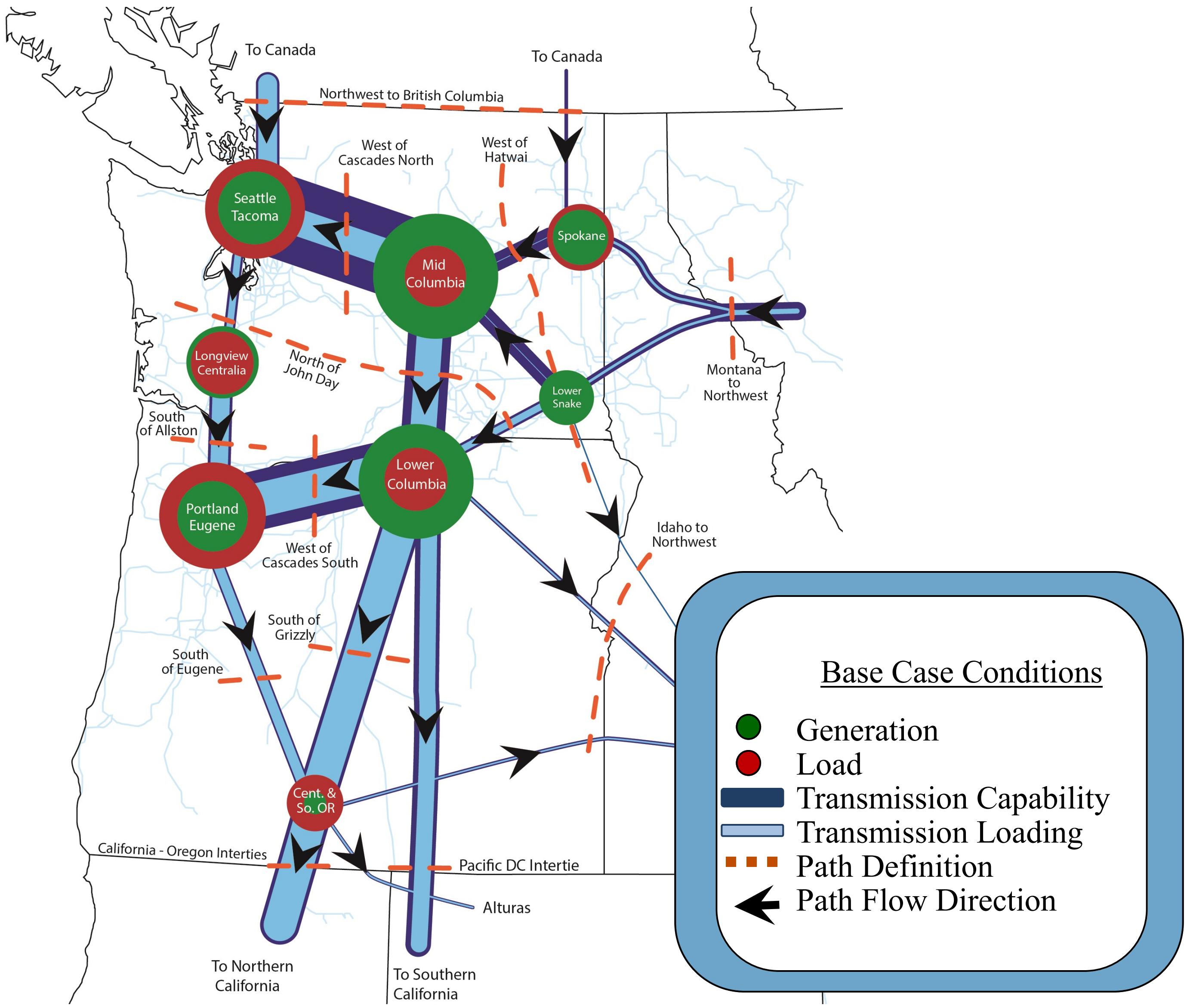


Figure I-2 Flows Modeled for One-Year Heavy Summer Peak Conditions

Longview/Centralia bubble includes the areas south of Tacoma through Longview and west to include the Olympic Peninsula. The Portland/Eugene area includes the Willamette Valley and Vancouver, Washington area. The Southern/Central Oregon bubble includes the Roseburg area down to the California border and east to the Bend-Redmond area. The Mid-Columbia area includes load in the Washington area east of the Cascades, west of Spokane, south of the Canadian border and north of the Columbia River. The Lower Columbia bubble includes loads to the south of Mid-Columbia to Central Oregon. The Spokane area includes loads to the east in Western Montana, north to the Canadian border and south to the Oregon border. The Lower Snake bubble includes the major generation in the area.

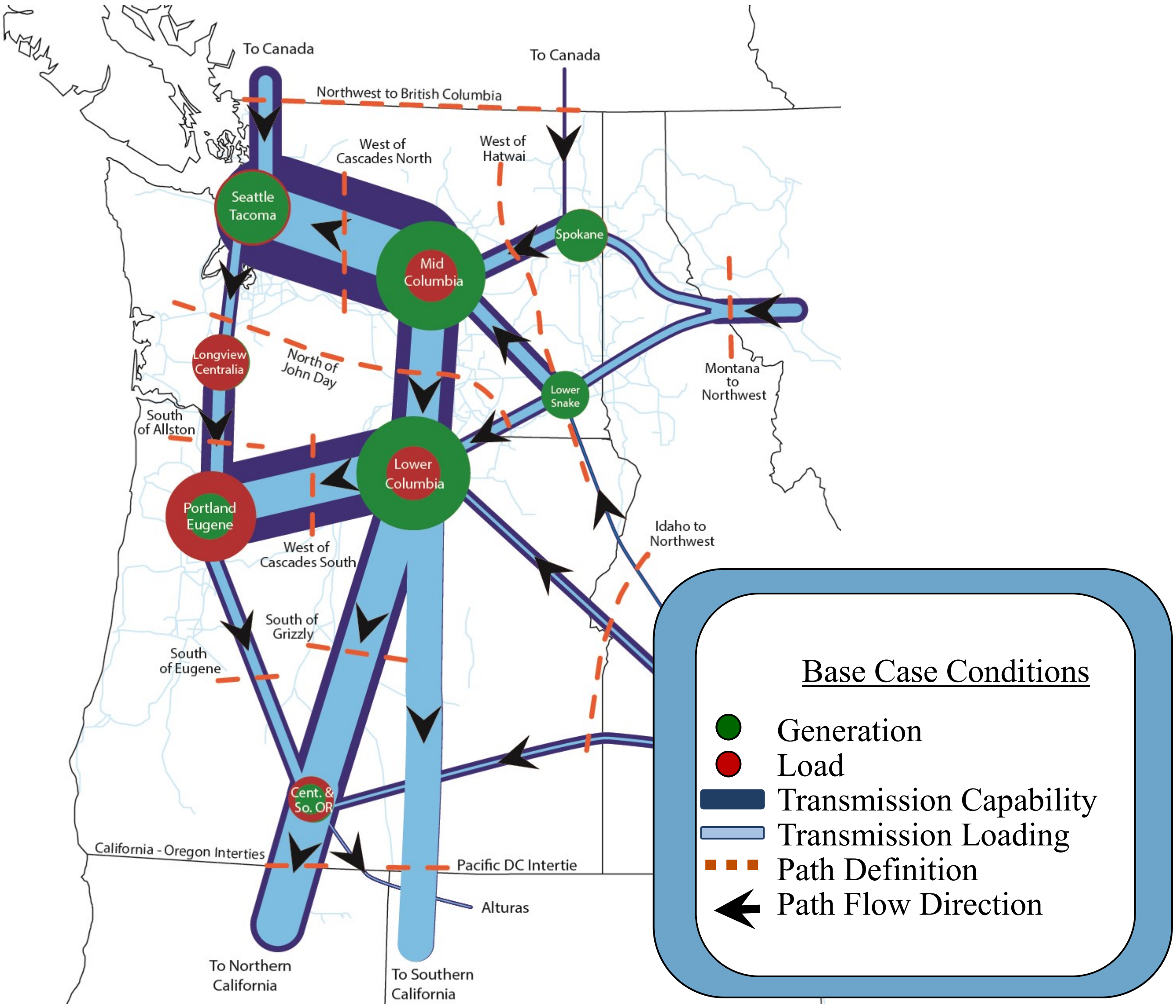


Figure I-3 Flows Modeled for One-Year Light Summer Peak Conditions

Figures I-1 and H-2 show the one-year peak winter and summer peak conditions.

Figures I-4 and I-5 show the five-year peak winter and summer peak conditions. Figures I-6 and I-7 show the ten-year peak winter and summer peak conditions. Figure I-3 shows the one-year light load condition.

The red circles in the figures represent the load levels in the identified areas; the load level is proportional to the area of the circle. The two major west side load areas, Seattle/Tacoma and Portland/Eugene, each have approximately 9,000 MW of load in the ten-year peak winter case as shown in Figure I-6.

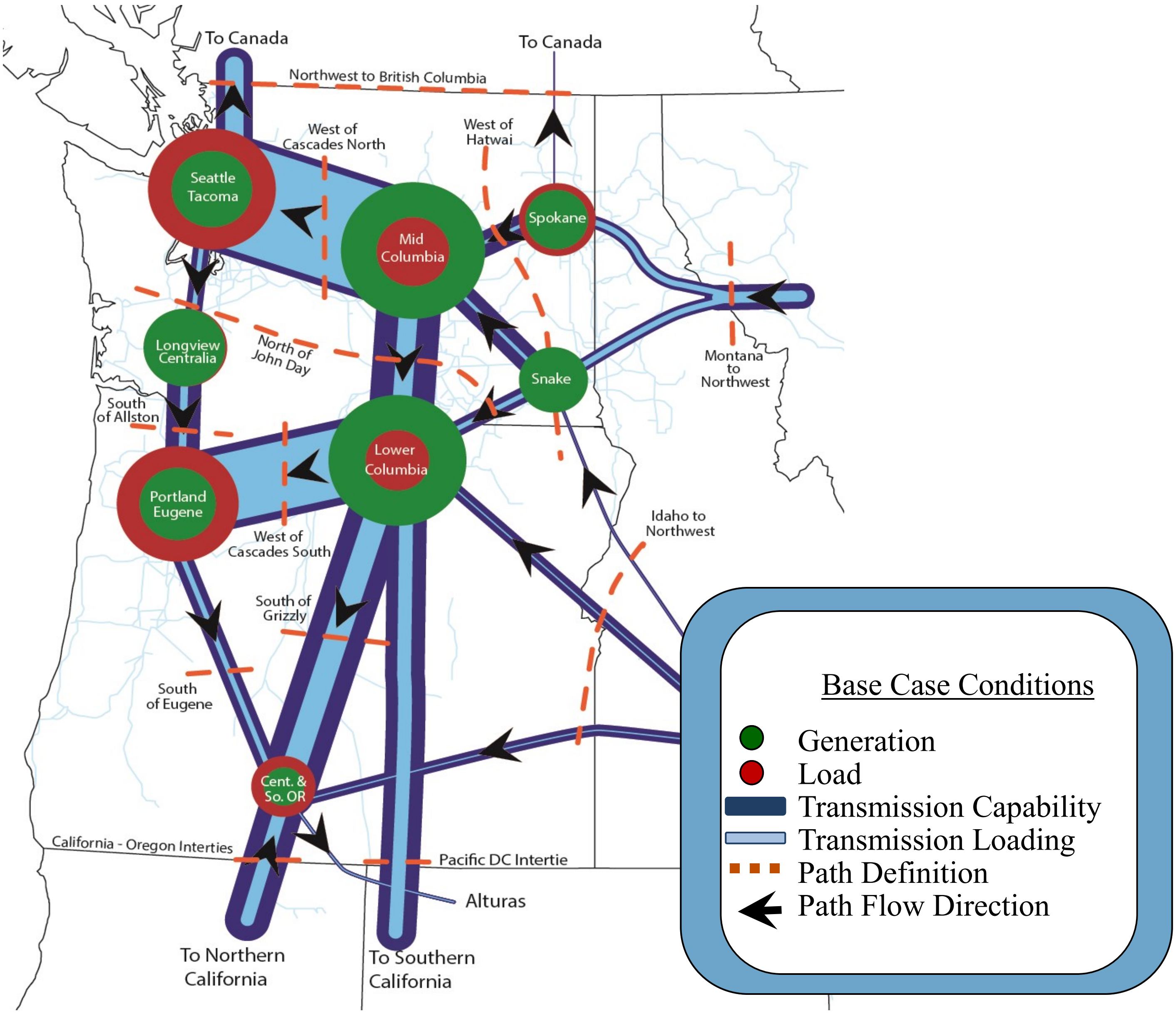


Figure I-4 Flows Modeled for Five-Year Heavy Winter Peak Conditions

The area of the green circles represents the amount of generation in that area. The Seattle/Tacoma and Portland/Eugene load areas have more load than generation and rely on other areas to supply the load resource balance. The Mid-Columbia, Lower Columbia, and Lower Snake areas have surplus generation that is used in other areas. The Mid-Columbia area has about 10,000 to 12,000 MW of generation represented in the peak load cases. The load/resource ratios in the Spokane, Central/Southern Oregon, and Longview/Centralia areas have greater balance.

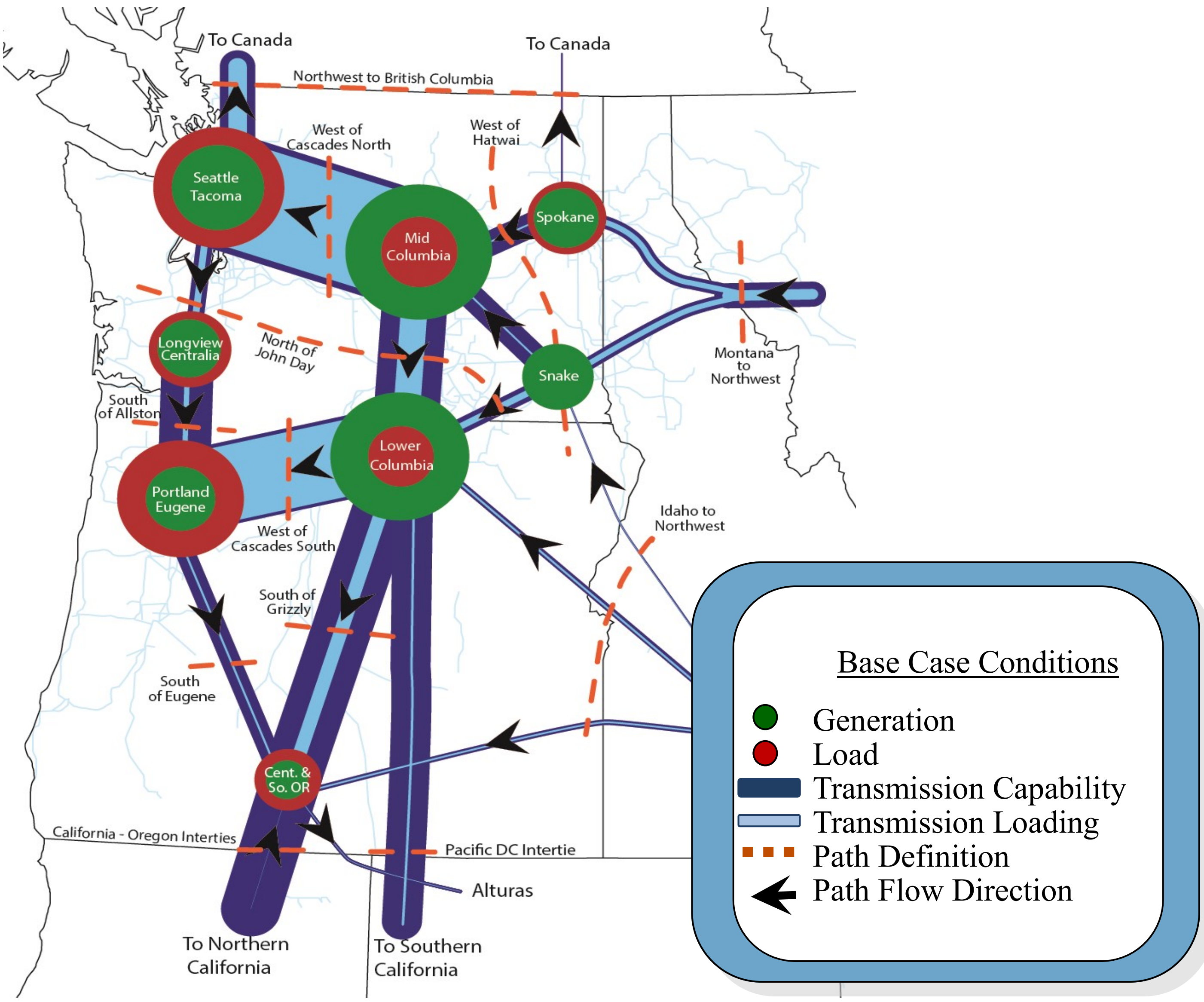


Figure I-6 Flows Modeled for Ten-Year Heavy Summer Peak Conditions

The dark blue lines between the areas represent the major transmission paths that connect the areas. The width of the dark blue lines represents the relative capacity of the paths. For example, the West of Cascades North path is rated at 10,200 MW. The light blue lines within these paths represent the capacity that is used in the studies. In the winter cases, the West of Cascades paths are heavily used to meet the load levels in the west side areas while the North of John Day and West of Hatwai paths are lightly loaded. The external path to Canada is loaded with the firm obligations on the path as discussed earlier which is mostly the downstream benefit return. Power is exchanged with California to balance overall load resource in the Northwest in the winter.

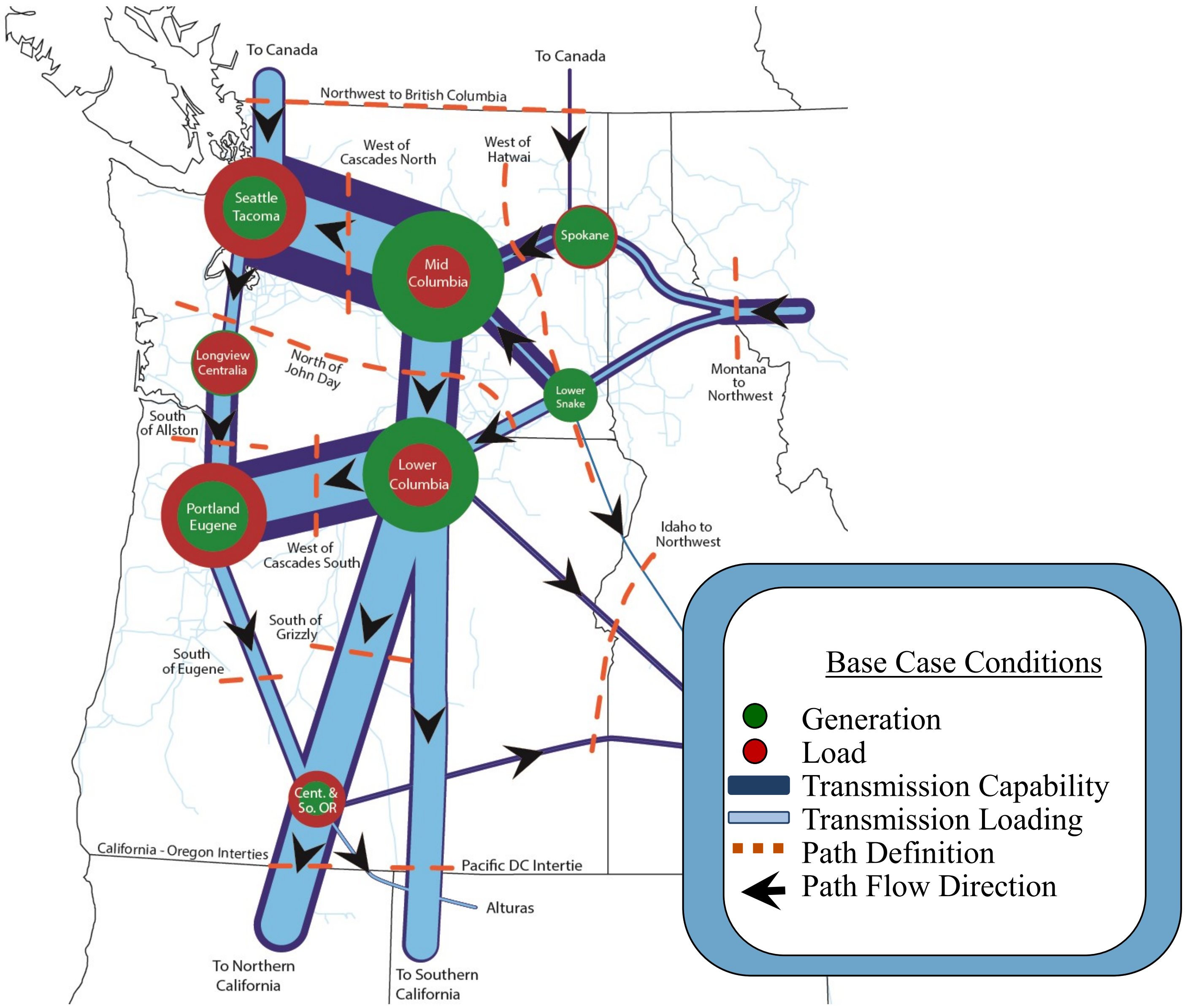


Figure I-5 Flows Modeled for Five-Year Heavy Winter Peak Conditions

The five-year peak summer conditions modeled in the base cases are shown in Figure I-5. The load levels are typically lower in summer than in winter in the west side areas and are shown here with proportionally smaller bubbles. Also note that the Portland/Eugene area load level is greater than Seattle/Tacoma in the summer. These two areas had similar load levels in the winter case. This difference is due to a greater use of air conditioning.

The path usage levels change significantly between summer and winter. In the summer, Canadian hydro generation capacity exceeds the internal loads in British Columbia. Excess energy is exported to the Northwest and California.

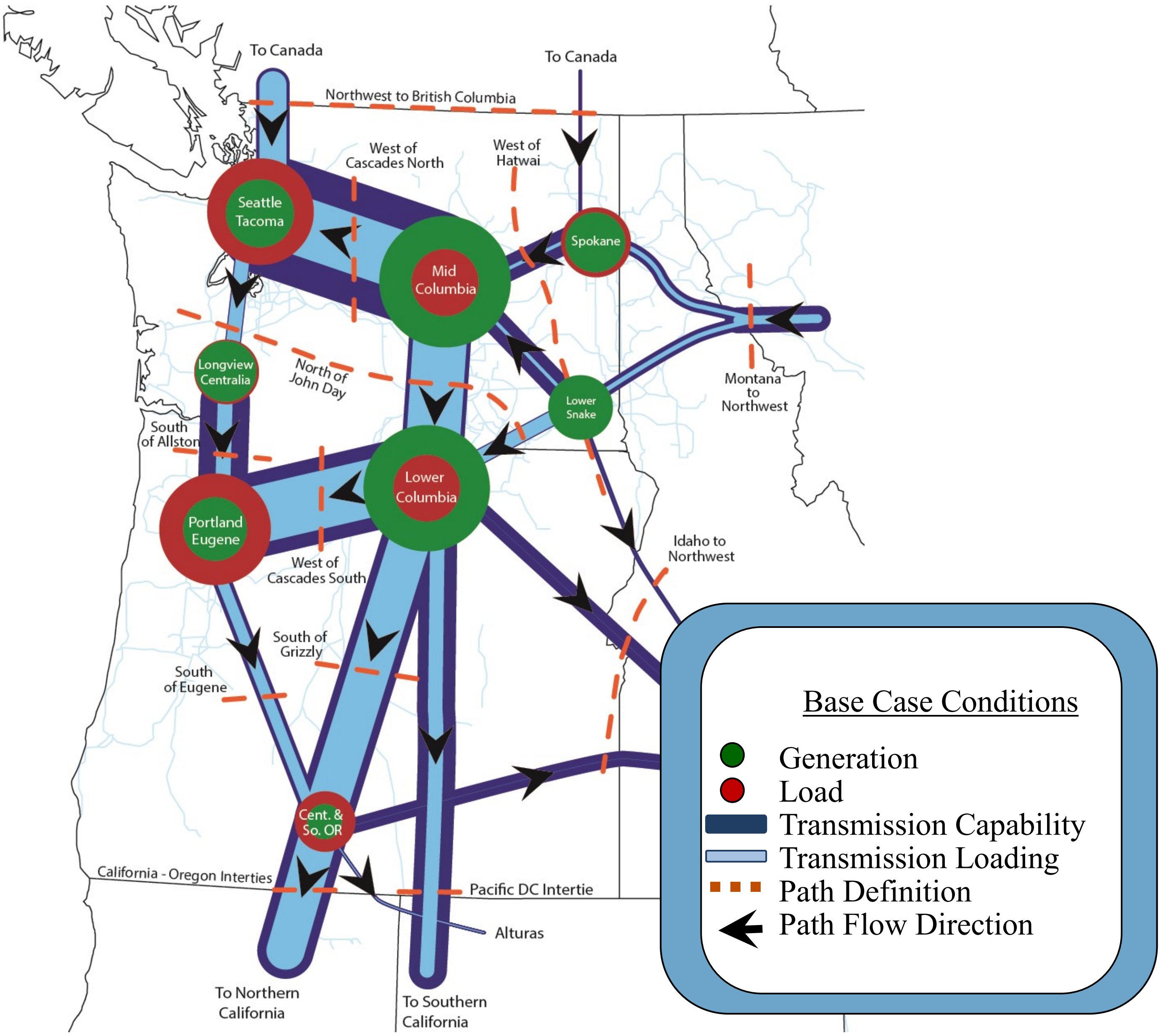


Figure I-7 Flows Modeled for Ten-Year Heavy Summer Peak Conditions

The lower Northwest load levels in summer also provide additional resources to export to the south. All of the north-to-south paths load much heavier in the summer due to these transfers. The loading on the west of Cascades paths is reduced in summer due to the reduced load level in the west side. The ties to Idaho are mostly floating with little power moving on that path.

Special Protection System Assumptions

At the transfer levels modeled in the base cases, existing Special Protection Systems (SPS) are required for reliable operation of the transmission system. Some of these SPS will trigger tripping or ramping of generation (some of which have firm transmission rights) for specified single and double line outages. SPS generation dropping systems rely on the use of operating reserves to meet firm transfer requirements (no schedule adjustments are made until the next scheduling period and no firm transfers are curtailed). If the outages are permanent, firm transfers might then need to be curtailed during the next scheduling period to meet the new operating conditions. Firm transmission service commitments are met with this use of SPS consistent with NERC and WECC standards.

Transmission Additions Modeled

Since the last System Assessment, the following projects have been placed in service:

1. Big Eddy - Knight 500 kV line and Knight Substation
2. Central Ferry - Lower Monumental 500 kV Line Project
3. Monroe 500 kV Capacitors
4. Sappho 69kV Shunt Capacitor Addition
5. Rocky Reach-Columbia #2 230 kV Line Upgrade
6. Rocky Reach-Chelan #1 115 kV Line Upgrade
7. Rocky Reach 230/115 kV Autotransformer #2
8. Whetstone 230/115 kV Transformer

These transmission additions and the future committed projects listed in Table K-1 were modeled in the base cases used in this System Assessment. These projects are fully described in Attachment B, entitled, Transmission Expansion Projects.

Committed Projects Included in All Cases	Sponsor	Date
Bronx - Cabinet 115 kV Line Rebuild	Avista	2016
Benton-Othello 115 kV Line Upgrade	Avista	2016
Westside 230 kV Rebuild and Transformer Upgrades	Avista	2016
Irvin Project - Spokane Valley Transmission Reinforcements	Avista	2016
Bell 230 kV Bus Section Breaker	Bonneville Power	2016
Pearl 500 kV Breaker Addition	Bonneville Power	2016
Columbia 230 kV Bus Section Breaker	Bonneville Power	2017
Alvey 500 kV Shunt Reactor	Bonneville Power	2016
Raver 500/230 kV Transformer, 230 kV line to Covington Substation	Bonneville Power	2017
Big Eddy 230/115 kV Transformer #1 Replacement	Bonneville Power	2017
North Bonneville - Troutdale 230 kV #2 Line Retermination	Bonneville Power	2016
Rapids - Columbia 230 kV line and Columbia Terminal	Douglas County PUD	2017
Rocky Ford - Dover 115 kV line	Grant County PUD	2016
Fry 115 kV Capacitors - 100 MVARs (2x20 MVARs, 2x30 MVARs)	PacifiCorp	2015
Snow Goose 500/230 kV Transformer (on Captain Jack - KFalls Cogen 500 kV line)	PacifiCorp	2017
Union Gap 230/115 kV Transformer #3	PacifiCorp	2017
Whetstone 230/115 kV Transformer	PacifiCorp	2015
Southwest Substation 230 kV Bus Reliability Improvement Project	Tacoma Power	2013-14
Longview - Lexington #2 upgrade from 69 kV to 115 kV	Cowlitz County PUD	2017
Longview - Lexington - Cardwell upgrade from 69 kV to 115 kV	Cowlitz County PUD	2017
South Cowlitz County Project	Cowlitz County PUD	2018

Table K-1 Committed Projects Included in all Cases

Committed Projects in 5 Year & 10 Year Cases		
Castle Rock - Troutdale 500 kV line (I-5 Corridor Reinforcement Project)	Bonneville Power	2020
McNary 500/230 kV Transfomer #2	Bonneville Power	2018
Salem - Chemawa 230 kV Line Upgrade	Bonneville Power	2018
Troutdale 230 kV Bus Section Breaker	Bonneville Power	2018
Lower Valley Reinforcement - Hooper Springs	Bonneville Power	2019
John Day - Big Eddy 500 kV #1 line reconductor	Bonneville Power	2019
Celilo Terminal Replacement (PDCI upgrade 3220 MW)	Bonneville Power	2019
Paul 500 kV Shunt Reactor	Bonneville Power	2018
Tacoma 230 kV Bus Section Breaker	Bonneville Power	2018
Hemingway - Boardman 500 kV line	Idaho Power/BPA	2020
Vantage - Pomona Heights 230 kV Line (short route)	PacifiCorp	2018
Table Mountain 500/230 kV Transformer (on Dixonville - Meridian 500 kV line)	PacifiCorp	2019
Troutdale East - Blue Lake - Gresham 230 kV line	Portland General Electric	2018
Horizon Phase II Project	Portland General Electric	2018
Harborton Reliability Project	Portland General Electric	2021
Eastside Project: Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot line rebuild to 230 kV	Puget Sound Energy	2018
Alderton 230/115 kV transformer in Pierce County	Puget Sound Energy	2018
Bothell - SnoKing 230 kV Double Circuit Line Reconductor	Seattle City Light/BPA	2018
Denny - Broad and Massachusetts - Union - Broad 115 kV Series Inductors	Seattle City Light	2018
Denny Substation - Phase 1	Seattle City Light	2018
Upgrade Denny Substation Transmission - Phase 2	Seattle City Light	2021
Delridge - Duwamish 230 kV Line Reconductor	Seattle City Light	2018
Swamp Creek 115 kV Switching Station	Snohomish County PUD	2018
Turner - Woods Creek 115 kV Line	Snohomish County PUD	2020
Berverly Park 230/115 kV Transformer	Snohomish County PUD	2018
Re-configureNavy - Everett -Kimberly Clark	Snohomish County PUD	2021
Cowlitz 230 kV Substation Reliability Improvement Project	Tacoma Power	2018
Potlatch System New Ring Bus Switchyard	Tacoma Power	2018
Pearl Cushman Upgrade	Tacoma Power	2018

Table K-2 Committed Projects Included 5 Year and 10 Year Cases

Committed Projects in 10 Year Cases Only		
Schultz - Raver 500 kV Series Capacitors	Bonneville Power	2025
Blue Lake/Gresham Phase II Project	Portland General Electric	2022
Woodland - Gravelly Lake 115 kV Line	Puget Sound Energy	2025

Table K-3 Committed Projects in 10 Year Cases Only

Transmission Projects included in the Base Cases

Major Additions in the Two-Year Case

The following projects were included in all of the two-year, five-year, and ten-year System Assessment base cases.

Mid-Columbia Area Reinforcements

The plan for the Northern Mid-C area that has been developed in the ColumbiaGrid Northern Mid-C Study Team was included. It includes Grant County PUD's Columbia-Larson 230 kV line; Douglas PUD's Douglas-Rapids-Columbia 230 kV line, Rapids Substation, including a 230/115 kV transformer; and Chelan County PUD's Rocky Reach-McKenzie 115 kV line upgrade, line re-terminations at Chelan's Andrew York Substation, and re-rates on the McKenzie-Andrew York #1 and #2 115 kV lines and Wenatchee-McKenzie 115 kV line. All of these projects are energized except for the Rapids-Columbia portion of the Douglas-Rapids-Columbia 230 kV line project which is expected to be energized in 2017.

Snow Goose 500/230 kV Transformer

The PacifiCorp Snow Goose transformer project on Captain Jack-Klamath Falls Cogen 500 kV line is planned for 2017 in the Klamath Falls area and provides another 500/230 kV source to the area.

Benton-Othello Line Upgrade

Avista is planning to upgrade the Benton-Othello 115 kV line. This project will be the focus of the Big Bend Study Team when it is organized.

Westside Transformer

Avista is planning to upgrade their Westside 230 kV substation and replace the 230/115 kV transformers.

Major Additions in the Five-Year Case

The following projects were included in all of the five-year and ten-year System Assessment base cases.

Puget Sound Area Transmission Expansion Plan Reinforcements

Six projects were recommended in the expansion plan developed by the Puget Sound Area Study Team. These projects include reconductoring the Bothell-SnoKing 230 kV double circuit line, reconductoring the Delridge-Duwamish 230 kV line, installing a Raver 500/230 kV transformer, a Lakeside Substation 230/115 kV transformer, Northern Intertie RAS extension to include the combined loss of Monroe-SnoKing-Echo Lake and Chief Joseph-Monroe 500 kV lines, and adding series inductors to the Massachusetts-Union-Broad and Denny-Broad 115 kV underground cables. The Raver 500/230 kV transformer project would add a new 500/230 kV transformer at Raver substation and would utilize an existing transmission line to create a new Raver-Covington 230 kV line. The Eastside Project would add a 230/115 kV transformer at Lakeside Substation and rebuild both Sammamish-Lakeside-Talbot 115 kV lines to 230 kV. Only one line will be initially operated at 230 kV and the other line will remain operated at 115 kV. Alternatives are currently being considered for the northern intertie RAS extension project so this was not modeled in the base cases. These projects support south to north transfer capability on the Northern Intertie and load service reliability in the Puget Sound area. The Puget Sound Area Study Team reevaluated the need for the Delridge-Duwamish 230 kV line reconductor, determined that the load changes in the projected system conditions have alleviated the limitations identified to originally justify the project, and recommended that the project should be delayed. Cost allocation for these projects has been agreed to by the affected parties. These projects are planned to be energized by 2018.

Denny Substation Phase 1 Project

Phase 1 of the Denny Substation project creates a new 115/13 kV Denny substation looped into the East Pine-Broad 115 kV underground cable. Some load would be transferred to this substation from Broad Street substation. This project is planned to be in service in 2018.

Troutdale-Blue Lake-Gresham Project

The Portland General Electric (PGE) Blue Lake-Gresham project is planned for 2018 in east Portland and consists of a new six mile 230 kV line between PGE's Blue Lake and Gresham substations, and a second 1.5 mile 230 kV line between PGE's Blue Lake substation and Bonneville Power Administration (BPA)'s Troutdale substation.

Vantage-Pomona Heights 230 kV Line

PacifiCorp is planning to add a 230 kV line in central Washington between Vantage and Pomona Heights. The line is planned to be completed in 2018 and will provide increased transmission capability in the area.

Hemingway - Boardman 500 kV Project

This Idaho Power project includes a 300-mile 500 kV line from the Boise Idaho area to Boardman substation. This project is intended to provide 1,050 MW of capacity in the west to east directions and 1,000 MW in the east to west direction. This project is planned to be completed by 2020.

I-5 Corridor Reinforcement Project

This Bonneville project consists of a 70-90 mile 500 kV line from a new Castle Rock substation north of Longview to Troutdale substation east of Portland. The project is scheduled to be energized in the 2020 timeframe and is planned to remove the most limiting bottleneck along the I-5 corridor, the South of Allston Cutplane.

Denny Substation Phase 2 Project

Seattle City Light is planning the second phase of the Denny Substation project for 2021. This project expands on Phase 1 of the Denny Substation project by adding a new 115 kV transmission line from Massachusetts Street substation to Denny substation.

Celilo/PDCI Replacement/Upgrade Project

This Bonneville project will replace the aging equipment at the northern Celilo terminal of the PDCI (the southern terminal at Sylmar has already been replaced). This project is planned to be completed in 2019 and will increase the capacity of the PDCI from 3,100 MW to 3,220 MW.

Pearl-Cushman Upgrade Project

This Tacoma Power project is expected to be completed in 2018 and will reconfigure a portion of the transmission system in Tacoma's north end. The project will decommission Cushman substation, rebuild the Pearl-Cushman line with two circuits rather than the single circuit presently operating.

Major Additions in the Ten-year cases

The ten-year System Assessment cases also included some additional projects beyond those in the five-year cases. There were a few projects that utilities have committed to build, however, due to significant lead times they are not expected to be completed until the latter part of the ten-year planning horizon. These additional projects were only included in the ten-year cases and are listed below:

Raver-Schultz 500 kV Series Capacitors

Bonneville is planning on adding additional series capacitors to the Raver-Schultz 500 kV lines. Adding the capacitors will enhance the transmission capability to move resources from the east side of the Cascades to the west side load centers. The project is scheduled to be completed in 2025.

All transmission facility ratings included in this study were determined by the owner of the facility.

Base Cases

Seven base cases modeling differently stressed system conditions encompassing the ten year planning horizon were developed and used for this System Assessment. These include three (3) two-year, two (2) of five-year, and two (2) ten-year term base cases for winter peak load, summer peak load and light load conditions. The two-year cases used were based on the heavy summer operations case 2015HS4-OP, heavy winter operations case 2014-15HW3-OP, and light spring case 2017LSP1-S. The five-year cases used were based on the heavy winter case 2019-20HW1 and heavy summer case 2020HS2. The ten-year cases were based on the heavy winter case 2023-24HW1 and heavy summer case 2024HS1. These cases were originally updated for last year's System Assessment. The final System Assessment cases from last year were updated this year with new load and generation profiles, topology corrections, and project changes to account for changes in planning in-service dates. More detail on each of the cases which includes the modifications made to the starting base case is provided below:

Two-year cases

•Two-year heavy summer: Starting with 2015HS4-OP case with loads increased to model 2018 heavy summer and a new 325 MW Carty generator added. Hydro generation levels in the Columbia Basin were adjusted to make up for the changes made in load and generation.

•Two-year heavy winter: Starting with 2014-15HW3-OP case with loads increased to model 2017-18 heavy winter and a new 325 MW Carty generator added. Transfers from California were adjusted to make up for the changes in load and generation.

•Two-year light load: Starting with 2017LSP case with loads increased to model 2018 light spring and wind generation increased to 35% of capacity. Hydro generation levels in the Columbia Basin were adjusted to make up for the changes made in generation.

Five-year cases

•Five-year heavy summer: Starting with 2020HS2 case with loads increased to model 2021 heavy summer and one Centralia unit removed from service. Hydro generation levels in the Columbia Basin were adjusted to make up for the changes in generation.

•Five-year heavy winter: Starting with 2019-20HW1 case with loads increased to model 2021-221 heavy winter, one Centralia unit removed from service, and a new 325 MW Carty generator. Transfers from California were adjusted to make up for the changes in load, generation, and transfers.

Ten-year cases

•Ten-year heavy summer: Starting with 2024HS1 case with loads increased to model 2026 heavy summer, both Centralia units removed from service and a correction to the 325 MW Carty generator model. Hydro generation levels in the Columbia Basin were adjusted to make up for the changes in generation and load.

•Ten-year heavy winter: Starting with 2023-24HW1 case with loads increased to model 2025-26 heavy winter, both Centralia units removed from service, and a correction to the 325 MW Carty generator model. Transfers from California were adjusted to make up for the changes in load, generation, and transfers.

The transmission configuration in each of the cases was updated to include the committed projects listed in Table K-2.

All of the base case assumptions, such as the load levels and the transmission projects, were selected by the ColumbiaGrid Planning participants during open meetings. Corrections and updates to the transmission system were made to all of the cases to ensure their consistency. Each case was analyzed under pre-outage and outage conditions, and any deficient areas were noted and corrections or updates were made as appropriate.

Study Methodology

The system was analyzed for all base cases without outages (N-0 conditions) and tuned to be within required voltage limits. Any voltage violations or facility overloads that could not be resolved through this tuning were noted.

All single element (N-1, defined as NERC Category P1 and P2 events) outages down to 115 kV were studied on each base case. Participants in the System Assessment provided ColumbiaGrid information on multiple contingencies that they wanted studied. These included common-mode outages, which are plausible outages of multiple facilities caused by a single event, also called Category P3, P4, P5, P6 and P7 events. These common-mode outages are listed in Attachment C (CEII protected and available upon request). Included in this System Assessment were inadvertent breaker openings, which are especially important on multi-terminal lines. The System Assessment also included known automatic and manual actions associated with each contingency. Facility loadings greater than 98% were identified in the results along with voltage violations.

On April 1, 2012, the WECC Planning Criteria for adjacent circuits was changed to include only circuits within 250 feet of each other if both circuits are greater than 300 kV. The previous criteria which did not specify a voltage level and the minimum circuit spacing was based on the maximum span length between towers typically on the order of 1000 feet or more.

In identifying voltage violations, the WECC criteria of no more than 5% voltage drop following a Category P1 or P2 contingency or 10% voltage drop following a credible Category P3-P7 contingency was used. Outages that did not solve were noted for further exploration.

Participants were not only asked to review outages of their facilities that caused problems, but also to review any violation of limits on their facilities that were caused by any other owner's outage. ColumbiaGrid staff also reviewed the results. Participants were also encouraged to provide a peer review of all results regardless of ownership.

Although the focus of this System Assessment is the facilities of the PEFA planning parties, the interconnected nature of the system requires that neighboring facilities are also modeled to determine if there are any interactions between systems. As mentioned earlier, ColumbiaGrid invited the owners of systems neighboring PEFA parties to participate in the System Assessment.

All study results were available to the planning participants. Single system issues (events where the outage facility and the overloaded facilities were owned by the same utility) were assumed to be the responsibility of that utility only. This report focused on joint issues where the outages and associated overloads were owned by multiple utilities, and joint transmission planning efforts may be needed.

Study Results and Need Statements

In this section, potential reliability issues that were identified from this year's System Assessment are discussed. These issues include voltage problems, voltage stability issues, unsolved outages, and facility overloads. The joint areas of concern include the parts of the system that will require additional analysis.

Voltage Problems

Voltage problems were addressed with the practices that were conducted in the previous System Assessment. In general, when potential reactive issues were identified, interim corrective action was proposed by assuming capacitor additions will be used. These capacitor additions are just one way that transmission operators might choose to resolve these voltage issues. In order to identify locations where additional reactive power might be needed, WECC criteria which require no more than 5% voltage drop following a credible category P1/P2 contingency or 10% voltage drop following credible category P3-P7 (multiple) contingency were used. The reactive support to prevent voltage violations were assumed to be installed at the 230 and 500 kV buses. For this assessment, the total reactive additions necessary to mitigate voltage problems for the ten-year planning horizon totaled 125 MVARs of shunt capacitors in 4 locations, all at the 230 kV level. This year's reactive additions are listed in table J-1.

Substation	MVARs	Owner
Cascade Steel	90	Bonneville
Chiloquin	10	PacifiCorp
Nickel Mountain	15	PacifiCorp
Pilot Butte	10	PacifiCorp

Table L-1 Potential Reactive Mitigation Projects

Substation	MVAR's	Owner
Tahkenitch	80	Bonneville
DeMoss	6	Bonneville

Table L-2 Potential Reactive Mitigation Projects for Stability Issues & Unsolved Outages

Voltage Stability Issues and Unsolved Outages

The unsolved outages listed in Attachment C of the 2016 System Assessment (CEII protected) required further investigation to determine the cause and mitigation of the failed solutions. Outages involving several areas of the system were investigated:

- Olympic Peninsula area in western Washington
- Kitsap Peninsula area in western Washington
- Sandpoint-Libby area in northwestern Montana/northern Idaho
- Santiam, Willamette Valley
- LaPine, central Oregon area
- Alturas, California area
- The Southern Oregon Coast
- Dworshak, Western Idaho
- The Wasco area in north central Oregon
- Redmond-Bend area in central Oregon
- Medford area in southern Oregon

All unsolved outages were tested with the WECC post transient power flow solution methodology, which eliminated simulation of manual and slow automatic actions. Failed solutions are often caused by either modeling issues, modeled conditions exceeding voltage stability, or angular stability solution limits. As a screening tool to obtain solved power flow solutions, the voltage threshold for voltage sensitive loads was set to 0.90 per unit voltage. During the power flow solution iterations, if the voltage at a load is below 0.90 per unit, the load is no longer constant power and it decreases with voltage. The decrease is nonlinear to facilitate the solution. The sections below provide more details on unsolved cases and potential mitigation plans in each geographical area. The required MVAR levels are summarized in table L-2 and total 86 MVARs.

In the Olympic Peninsula area, under heavy winter loading conditions, a number of breaker failures, single outages, and double outages along the major 230 kV and 500 kV corridor in this area such as the breaker failure at Fairmont, Olympia 230 kV East, loss of Fairmont – Happy Valley 230 kV line, and Shelton – Fairmount 230 kV lines #3 and #4 could cause voltage instability. These contingencies resulted in the loss of connection between the load centers in this area from its major supply and resulted in low voltages in the Olympic Peninsula area. Mitigation plans for these voltage problems include; Fairmount Backtripping Scheme, transformer tap settings adjustment at Fairmount, Port Angeles and Sappho; a 7 MVAR shunt capacitor at Sappho; and tripping about 130 MW of load through an under voltage load shedding (UVLS) scheme at Port Angeles.

Outages at Kitsap substation could lead to low voltage in the Kitsap peninsula area during all heavy winter conditions and 2026 heavy summer conditions. This problem can be mitigated by switching on local capacitors in Foss Corner and Valley Junction. RAS action to shift and drop loads also helps to address the local low voltage issue in the Kitsap peninsula. Other mitigation plans include a number of planned projects such as the West Kitsap Phase II project which would ultimately add a 230 kV line between BPA Kitsap and Foss Corner with a 230/115 kV transformer at Foss Corner.

Potential instability in Sandpoint/Libby area was identified in the 2026 heavy summer cases due to the N-2 outage of Libby – Conkelly and FlatHead – Hot Spring 230 kV lines which removes the major transmission out of Libby powerhouse from service. The investigation results showed that a possible mitigation plan to this problem is to limit the amount of Libby generation to approximately 110 MW under these conditions (a tripping scheme similar to this is in place but not modeled.)

Instability in the central Oregon coast area was also identified due to the loss of Santiam – Wren 230 kV line under 2027 heavy winter conditions which resulted in low voltages around the Wren 230 kV bus. This potential problem can be mitigated with a new 80 MVAR reactive addition at Tahkenitch (along the coast near Florence, Oregon). There may also be local RAS that addresses this issue.

The outage of La Pine 230/115 kV transformer results in voltage collapse around La Pine 115 kV system under heavy winter, heavy summer and light spring conditions. With the contingencies, voltage collapse occurs when power flows through a radial 115 kV line from Christmas Valley to serve loads at La Pine 115 kV substation. Such a voltage collapse is likely a modeling issue where the Christmas Valley Tap operated normal open was modeled as closed in the base cases.

A similar situation occurred in 2018 heavy summer cases when voltage instability occurred following the outages of the Hilltop – Warner or Warner – Alturas 230 kV lines that supply Alturas area loads. Switching online a local capacitor at Alturas 69kV and updating the loads in the area can help to mitigate the problems.

The outage of Fairview and Reston 230 kV buses resulted in instability in all cases. In general these contingencies disconnect the Fairview 115 kV system from its 230 kV source which could trigger voltage instability. It is very likely that this problem was caused by a modeling issue of the reactive support from the Rogue 115 kV SVC.

In the Dworshak area near the Idaho/Washington border, several breaker failure contingencies opening a Dworshak 500/100 kV step-up transformer could result in voltage instability. This is due to the fact that power from Dworshak generation units previously fed into the 500kV system through the transformer has to be re-routed to the 115kV line to Orofino. These voltage problems can be mitigated by local RAS which was not modeled in the cases.

In the Wasco area, a breaker failure at the Big Eddy 115 kV bus could result in voltage instability under heavy winter conditions. The addition of approximately 6 MVAR of reactive support around the De Moss 115 kV bus can mitigate this problem.

For the Redmond-Bend area, a contingency opening two 230/69 KV transformers at Pilot Butte substation could result in voltage instability of the 69 kV system in heavy winter cases. A remedial action of opening the third 230/69 kV Pilot Butte transformer to isolate the 69kV system from the main grid has been designed to save the system from instability.

In the Medford area in southern Oregon, an outage of the Baldy to Campbell 115 kV line led to voltage collapse of the local 115 kV system. Such problems can be resolved by changing the normally open conditions in the area which shifts the load at Jacksonville to another 115 kV transmission line from Sage Road.

Generation Project	18HS	21HS	26HS	17-18HW	21-22HW	26-27HW	18LSP
Adair	6	6	6	6	6	6	6
Albeni Falls	28	28	28	28	28	28	28
Alder	22	22	22	30	30	30	34
Beaver	320	320	320	250	250	250	0
Big Cliff	0	0	19	0	0	19	0
Biomass	10	10	10	10	10	10	10
Boardman	580	580		580	580		0
Bonneville	1012	1080	1012	1090	1094	1088	629
Boulder	0	0	0	0	0	0	0
Boundary	869	590	529	567	682	836	898
Box Canyon	14	74	74	58	73	65	75
Boyle	61	61	61	61	61	61	61
Bull Run	5	5	5	20	20	20	22
Cabinet Gorge	240	240	220	185	185	180	240
Camas Mill	11	23	23	11	23	11	23
Carmen	47	47	47	56	50	30	76
Carty	330	330	330	330	330	330	0
Cedar Falls	1	2	0	5	26	19	12
Centralia	1424	712	0	1424	712	0	712
Chandler	7	7	7	7	7	7	7
Chehalis	513	513	513	513	513	513	0
Chelan	62	62	55	60	60	62	62
Chemical	45	50	50	45	50	55	50
Chief Jo	1515	1897	1993	2185	2237	2090	690
Clearwater AVA	50	50	50	50	50	50	50
Clearwater PAC	20	11	11	20	11	11	40
Coffin Rock	20	0	15	20	0	15	15
Columbia Generating Station	1151	1151	1151	1151	1151	1151	1151
Copco	8	30	30	8	30	30	45
Cosmo SP Fiber	16	16	16	16	16	16	16
Cougar	13	13	13	13	13	12	13
Coulee	4697	5755	4729	5936	5872	5864	4115
Covanta	13	13	13	13	13	13	13
Cowlitz Falls	40	40	40	40	40	40	40
Coyote Springs	500	500	240	520	520	520	0
Cushman	30	52	52	101	101	101	45
Detroit	52	52	104	52	104	104	52
Dexter	14	14	14	14	14	14	14
Diablo	157	80	110	155	79	99	57
Dworshak	92	316	316	316	408	408	316

Generation Project	18HS	21HS	26HS	17-18HW	21-22HW	26-27HW	18LSP
Electron Heights	14	14	14	14	14	14	0
Enid Road	16	16	16	16	16	16	16
Enserch	157	157	155	180	180	182	163
Evergreen Bio	10	10	10	10	10	10	10
Faraday	7	7	7	35	35	35	39
Ferndale	246	246	246	267	267	267	246
Finley	0	0	0	0	28	28	0
Fish Creek	6	4	4	6	4	4	11
Foster	5	9	5	5	18	5	20
Frederickson	134	134	134	162	156	162	144
Frederickson CCCT	249	0	0	249	249	249	0
Fredonia	281	281	281	349	349	349	304
Glenoma	29	29	29	29	29	29	29
Goldendale Energy Center	168	168	247	247	247	247	247
Gorge	171	119	122	160	78	154	117
Grays Harbor	0	0	0	619	609	609	0
Green Peter	0	0	0	0	40	0	0
Green Spring	16	16	16	16	16	16	16
Harbor Paper	19	19	19	0	19	19	19
Headwork	25	22	22	0	0	0	22
Hermiston Gen Project	469	234	234	469	469	468	0
Hermiston Power Project	557	557	557	557	557	557	557
Hills Creek	15	30	30	30	30	30	30
Hungry Horse	190	285	285	172	285	380	285
Ice Harbor	385	385	385	498	611	611	385
Iron Gate	10	17	17	10	17	17	17
Jackson	34	26	34	62	64	62	38
John Day	1938	1983	1801	2076	2160	1938	927
Kettle Falls	0	0	0	52	52	52	0
Klamath	0	424	424	424	583	583	100
Komo	0	0	0	0	0	0	0
Lagrande	28	28	28	55	55	52	52
Lake Siskiyou	1	1	1	1	1	1	4
Lancaster	241	229	249	249	246	249	0
Leaburgs	7	7	13	13	13	13	13
Lemolo	31	13	13	31	13	45	61
Libby Gen	108	323	539	324	431	539	323
Little Falls	32	32	32	24	24	32	32
Little Goose	555	555	694	833	833	833	416

Attachment A: Resource Assumptions for Base Cases (MW Output) Continued

Generation Project	18HS	21HS	26HS	17-18HW	21-22HW	26-27HW	18LSP
Longlake	84	84	84	84	84	84	84
Longview Fiber	27	27	27	27	27	27	27
Lookout Point	40	40	120	80	80	120	40
Lost Creek	15	30	30	30	30	30	30
Lower Baker	96	96	74	97	97	105	100
Lower Granite	554	554	832	693	693	832	416
Lower Monumental	531	533	785	669	804	787	413
March Point	147	147	138	147	147	150	147
Mayfield	64	64	64	129	129	129	84
McNary	717	850	1004	861	913	1004	510
Merwin	98	129	98	98	129	98	129
Mint Farm	0	0	235	235	235	235	235
Monroe A	11	11	11	14	14	14	14
Morro	0	0	0	0	0	0	0
Mossy Rock	0	173	173	259	259	259	286
Nine Mile	7	7	16	7	7	2	7
North Fork	9	9	9	44	44	44	44
Northeast	0	0	0	0	0	0	0
Noxon	420	420	419	400	400	285	420
Oak Grove	20	20	20	38	38	38	38
Pelton	105	105	105	105	105	105	48
Port Westward	378	378	378	399	399	399	0
Post Falls	10	10	10	8	8	10	14
Priest Rapids	614	526	614	702	702	877	525
Prospect	27	27	27	27	27	43	42
Rathdrum	0	0	0	0	0	0	0
River Road	230	230	230	250	250	209	0
Rivermill	5	5	5	20	20	20	23
Rock Island	350	301	352	367	365	365	502
Rocky Reach	970	970	975	861	854	976	1226
Ross	155	25	123	216	260	234	41
Round Butte	220	220	220	230	230	230	90
Roza	8	8	8	8	8	8	8
Sawmill	20	25	22	20	20	19	19
Slate Creek	1	1	1	1	1	1	3
Slide Creek	9	8	8	9	8	8	15
Smith Falls	36	0	0	0	0	0	0
Snoqualmie Falls	47	47	30	47	47	30	47
Soda Springs	6	5	5	6	5	5	10

Attachment A: Resource Assumptions for Base Cases (MW Output) Continued

Generation Project	18HS	21HS	26HS	17-18HW	21-22HW	26-27HW	18LSP
Spokane Waste	18	18	18	18	18	18	18
Stone Creek	5	5	5	5	5	5	5
Sullivan	15	15	15	16	16	16	15
Sumas	124	124	124	138	138	138	134
Summer Falls	90	90	89	0	0	0	90
Swift	110	209	145	110	209	143	210
The Dalles	1106	1366	1701	1548	1820	1688	1038
Tieton	6	6	6	6	6	6	6
Toketee	21	20	20	21	20	20	38
Tolt River	0	12	12	3	12	10	6
Twin Falls	0	0	0	0	0	0	0
Upper Baker	92	92	92	82	82	82	82
UpRiver	12	12	12	7	7	7	15
Wanapum	853	852	853	853	853	947	474
Wauna	32	32	32	32	32	32	32
Wells	720	640	720	720	720	720	400
Weyerhauser (EWEB)	25	25	25	25	25	25	25
White Creek	6	34	34	34	34	34	34
Whitehorn	134	134	134	162	162	162	144
Wynooche	3	3	3	0	3	2	3
Yale	60	35	35	59	35	60	94

Attachment A: Resource Assumptions for Base Cases (MW Output) Continued

Generation Project	18HS	21HS	26HS	17-18HW	21-22HW	26-27HW	18LSP
Big Horn Wind	0	0	0	0	0	0	105
Biglow Canyon Wind	0	0	0	0	0	0	157
Combine Hills Wind	0	0	0	0	0	0	36
Condon Wind	0	0	0	0	0	0	18
Dodge Jct Wind	0	0	0	0	0	0	67
Echo Wind	0	0	0	0	0	0	23
FPL_II_LT Wind	0	0	0	0	0	0	35
Goldendale Wind	0	0	0	0	0	0	70
Goodnoe Hills Wind	0	0	0	0	0	0	53
H Canyon Wind	0	0	0	0	0	0	35
Harvest Wind	0	0	0	0	0	0	0
Hopkins Ridge Wind	0	0	0	0	0	0	55
Horn Butte Wind	0	0	0	0	0	0	27
HS Hub Wind	0	0	0	0	0	0	102
Jordan Butte Wind	0	0	0	0	0	0	71
Juniper Creek Wind	0	0	0	0	0	0	0
Kittitas Valley Wind	0	0	0	0	0	0	37
Klondike Wind	0	0	0	0	0	0	104
Leaning Juniper Wind	0	0	0	0	0	0	105
Linden Wind	0	0	0	0	0	0	18
Marengo Wind	0	0	0	0	0	0	74
Miller Ranch	0	0	0	0	0	0	53
Mullan Wind	0	0	0	0	0	0	93
Nine Canyon Wind	0	0	0	0	0	0	33
Nine Mile Wind	0	0	0	0	0	0	32
Palouse Wind	0	0	0	0	0	0	37
Patu Wind	0	0	0	0	0	0	0
Pebble Springs Wind	0	0	0	0	0	0	35
PHLNG Wind	0	0	0	0	0	0	53
Rattlesnake Wind	0	0	0	0	0	0	35
Saddleback Wind	0	0	0	0	0	0	25
Shepards Flat Wind	0	0	0	0	0	0	194
Stateline Wind	0	0	0	0	0	0	74
STRPT Wind	0	0	0	0	0	0	35
TULMN Wind	0	0	0	0	0	0	14
Vansycle Wind	0	0	0	0	0	0	36
WEBFT Wind	0	0	0	0	0	0	35
White Creek Wind	0	0	0	0	0	0	84
WHT F Wind	0	0	0	0	0	0	34
Wild Horse Wind	0	0	0	0	0	0	95
Windy Flat Wind	0	0	0	0	0	0	21

Attachment A: Resource Assumptions for Base Cases (MW Output) Continued

Olympic Peninsula Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Sappho 69kV Shunt Cap Addition		Add 10 MVAR shunt capacitor to Sappho 69V	BPA			Energized
West Kitsap Transmission Project Phase II		Installation of 230/115 kV transformer at Foss Corner Substation along with a 230 kV line from Foss Corner to the future BPA Kitsap 230 kV Substation	PSE	BPA		Conceptual Project for future need

Central Washington Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impact-ed by Project	Link to More Detail	Project Stage
Columbia 230 kV Bus Section Breaker	ColGrid SA	Add a series bus section breaker at Columbia 230 kV substation	BPA			Plan of Service Deter-mined
Rapids-Columbia 230 kV Line and Columbia Terminal	ColGrid NMCST	Build new Rapids-Columbia 230 kV line	Douglas, Grant, Chelan, BPA	Douglas, Grant, Chelan, BPA	http://efw.bpa.gov/environmen-tal_services/Document_Library/NMC_Joint_Project/	Routing, design
Lone Pine Substation		Build a new 115-kV substation in between the Chelan Falls Substation and Brays Substation on the existing 115-kV line.	DOPD	DOPD, CHPD		Committed project
Mid-Columbia Area Reinforcement, Phase 2		Upgrade Wanapum-Midway 230 kV line in central WA.	Grant County PUD			
Veedol Substation		Build a new 115-kV substation in between Eastmont Substation and Pangborn Substation on the existing 115-kV line.	DOPD	DOPD		Committed project
Rocky Ford - Dover 115 kV Line	ColGrid SA	Construct 115 kV Rocky Ford-Dover 115 kV line	Grant County PUD			
Vantage-Pomona Heights 230 kV Line (Short Route)	ColGrid SA	Vantage-Pomona Heights 230 kV #2 Line in the Yakima area.	PAC	BPA, Grant		
Union Gap 230/115 kV Transformer #3	ColGrid SA	Add third 230/115 kV transformer at Union Gap	PacifiCorp			
Rocky Reach-Columbia #2 230 kV Up-rate to 100C MOT		Up-rate the Rocky Reach-Columbia #2 230 kV line to 100C MOT	CHPD			Completed
Rocky Reach-Chelan #1 115 kV Up-rate to 75C MOT		Up-rate the Rocky Reach-Chelan #1 115 kV line to 75C MOT	CHPD			Completed
Rocky Reach 230/115 kV Autotransformer #2		Replace Rocky Reach 230/115 kV autotransformers #1 and #2 with a single 333 MVA transformer - labeled #2	CHPD			Completed
Rocky Reach-Chelan #1 115 kV Retermination		Re-build the Rocky Reach-Chelan #1 115 kV line; line ownership transferred from CHPD to DCPD; line re-terminated from CHPD Rocky Reach station to DCPD Douglas or Douglas area station.	CHPD, DCPD			Project Under Study

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team (s)
Funding approved by sponsor	2016	$4.5 M	voltage support	Energized		Single System Project	
	2020+			Delayed from 2018		Single System Project with possible impacts	

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team (s)
Committed	2018	$2.0 M	Load service, Reliability			Single System Project	
Sponsors committed, cost allocation complete	2018	$23.25 M	Load growth and transfers Time extended for environ-mnetal studies	Project delayed from 2016	No	Existing Obligation Project	Northern Mid-Columbia Study Group
Committed	2020	$3 M	Load service for new customers transferred from Chelan PUD	New Project	No	Single System Project	
Project identified as future need	2025		Load growth, new wind generation plants and transfers of generation out of the area	Delayed from 2024		Existing Obligation Project	
Committed	2017	$4 M	Load growth	New Project	No	Single System Project	
	2017	$5 M	Increase transmission system reliability			Single System Project	
	2018		Load growth in Yakima area			External Project	NTAC
	2017		`		No	Single System Project	
Energized	2014		Operations Reliability	Energized	No	Single System Project	
Energized	2014		Operations Reliability	Energized	No	Single System Project	
Energized	2015		Equipment replacement	Energized	No	Single System Project	
Project identified as future need	2022		Load service	New Project	No	Joint project between CHPD and DCPD	

Attachment B: Transmission Expansion Projects Continued

Puget Sound Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Raver 500/230 kV transformer and a 230 kV line to Covington Substation.	ColGrid PSAST	Add a 500/230 kV transformer at Raver and a 230 kV terminal at Raver for a Raver-Covington 230 kV line.	BPA	PSE, SCL		design in-progress
Tacoma 230 kV Bus Section Breaker	ColGrid SA	Add a series bus section breaker at Tacoma 230 kV substation	BPA	PSE, TPWR		design in-progress
Paul 500 kV Shunt Reactor	ColGrid SA	Add 500 kV 180 MVAR Shunt Reactor	BPA			Plan of Service determined
Monroe-Novelty 230 kV line Upgrade		Increase capacity of Monroe-Novelty 230 kV line	BPA			under study
IP line conversion to 230 kV		Convert PSE's 115 kV "IP" line to 230 kV between Wind Ridge Substation and Lake Tradition Substation in King County to increase cross-Cascade capacity and interconnect Kittitas County wind projects	PSE	PSE		Canceled
East King County Transformer Capacity (Lake Tradition)		This project involves looping the Maple Valley-Sammamish #1 230 kV line into PSE's Lake Tradition Substation and installing a new 230/115 kV transformer.	PSE	BPA - loop through of BPA owned and PSE leased 230 kV line		Concepual Project for future need
Sedro-Woolley-Bellingham #4 115 kV line		Reconductoring Sedro-Woolley-Bellingham #4 115 kV line	PSE			Design and Construction
PSE Bellingham Substation Rebuild		Construct a new breaker and a half 115 kV substation	PSE			Project under study
White River Bus Improvements		Add 2nd 115 kV Bus Section breaker at White River (230 kV bus completed)	PSE			Design and Construction
Talbot 230 kV Bus Improvements		Improve 230 kV bus at Talbot: Terminate new 230 kV line from Lakeside. Revise 230 kV protection. This will be a phased process to construct a double bus double breaker configuration.	PSE	BPA - Talbot - Maple Valley #1 and #2 230 kV lines		Project under study
Berrydale 230 kV Transformer Addition		Install second 230/115 kV transformer at Berrydale Substation.	PSE			Conceptual Project for future need
Christopher 230 kV Substation		Develop Christopher 230 kV Substation: loop BPA Covington-Tacoma 230 kV line into Christopher, construct a 230 kV bus with the necessary breakers, and add 230/115 kV transformation and a 115 kV auxiliary bus.	PSE	BPA - Covington Tacoma #2,3,4 230 kV lines		Conceptual Project for future need
Alderton 230/115 kV Transformer in Pierce County	ColGrid SA	A new 230/115 kV transformer at Alderton Substation in central Pierce County with a new 230 kV line from White River.	PSE			Plan of Service determined
Woodland-Gravelly Lake 115 kV Line	ColGrid SA	Add new Woodland-Gravelly Lake 115 kV line	PSE			Design and Construction
Eastside Project: Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot Line Rebuilt to 230 kV	ColGrid PSAST	Rebuild the Sammamish-Lakeside-Talbot 115 kV lines and energize one at 230 kV and install a new 230/115 kV transformer at Lakeside.	PSE	BPA, SCL		Project identified in PSAST Expansion Plan
Bothell-Snoking 230 kV Double Circuit Line Reconductor	ColGrid PSAST	Reconductor SCL portion of Bothell-SnoKing 230 kV #1 and #2 with high temperature low sag conductor, and rebuild BPA portion of Bothell-SnoKing 230 kV #1 and #2	SCL, BPA	PSE		Preliminary Design
Denny Substation (Phase 1)	ColGrid PSAST	New 225 MVA substation in the north downtown Seattle area. Loop existing East Pine-Broad 115 kV line.	SCL			Construction
Upgrade Denny Substation Transmission	ColGrid PSAST	New transmission line from Massachusetts Substation to Denny Substation (built at 230 kV, operated at 115 kV).	SCL			Conceptual Design
Denny - Broad and Massachusetts - Union - Broad 115 kV Series Inductors	ColGrid PSAST	Add 6 ohm inductors on Denny - Broad and Massachusetts - Union - Broad 115 kV underground cables. 115kV Capacitor Bank at Broad Substation.	SCL	BPA, PSE		Preliminary Design
Additional capacity for the North County area	ColGrid PSAST	North County 230/115 kV Transformer Addition	Snohomish County PUD	BPA		Project under study
Cowlitz Substation 230 kV Bus Reliability Improvement Project.		Modify the bus section breaker arrangement at Cowlitz Substation to eliminate single point of failure of bus section breaker.	Tacoma Power			Conceptual Project for future need
Delridge-Duwamish 230 kV Line Reconductor	ColGrid PSAST	Reconductor Delridge - Duwamish 230 kV Line with high temperature low sag conductor	SCL	BPA, PSE		Preliminary Design
Beverly Park 230/115 kV Transformer	ColGrid PSAST	Rebuild the existing 115 kV switching station and add one 230/115 kV 300 MVA transformer at Beverly Park. An existing 115 kV line from BPA Snohomish to the Glenwood Tap will be converted to 230 kV to provide the source for this substation. Add a new 115 kV line from Everett.	Snohomish County PUD	BPA		Project is in the design and construction Phase
Swamp Creek 115 kV Switching Station	ColGrid PSAST	Construct a four breaker 115 kV switching station with a ring bus arrangement. This switching station will terminate 115 kV lines from SnoKing, Halls Lake, Brightwater and Beverly Park.	Snohomish County PUD			Plan of service determined
Reconfigure Navy-Everett-Scott	ColGrid SA	Reconfigure Navy-Everett-Scott to Navy-Scott and Everett-Scott	Snohomish County PUD			Plan of service determined
Turner-Woods Creek 115 kV Line	ColGrid SA	Build a new Turner-Woods Creek 115 kV line for new distribution substations	Snohomish County PUD			Plan of service determined
Potlatch System New Ring Bus Switchyard		The proposed new ring bus switchyard in the Potlatch System will consist of 4 breakers and 4 terminals. Two of the terminals will be used for the Potlatch lines and the other two terminals will be used for the lines coming in from Cushman 1 and Cushman 2.	Tacoma Power			Design
Pearl Cushman Upgrade		This project will reconfigure a portion of the transmission system in Tacoma's north end. The project will decommission Cushman substation, rebuild the Pearl Cushman line with two circuits rather than the single circuit presently operating.	Tacoma Power			Design

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team (s)
Committed	2018	$60 M	Load growth in Puget Sound area			Existing Obligation Project	Puget Sound Area S.Team
Committed	2018	$0.8 M	Load service, Capacity increase, Reliability			Existing Obligation Project	
Committed	2016	$10.4 M	Maintain voltage schedules			Single System Project	
	2019	$2.9 M					
	2020+		Load growth in Puget Sound and generation integration, related to North Cross Cascades Improvements	Canceled		Capacity Increase Project	West of Cascades Study Team
	2025+	$13 M		Delayed from 2020+		Single System Project, possible impacts	Puget Sound Area Study Teams
Included in sponsors budget	2021	$14 M		Delayed from 2018		Single System Project	
Project identified as future need	2020	$20 M		Delayed from 2019		Single System Project	
Included in sponsors budget	2020+	$0.6 M	Reliability			Single System Project	
Included in sponsors budget	2018+	$11 M	Phased Construction 2016 - 2018	Delayed from 2017		Single System Project	
Project identified as future need	2025+	$8 M		Delayed from 2018+		Single System Project	
Project identified as future need	2025+	$20 M		Delayed from 2018		Single System Project	
Included in sponsor's budget	2018	$28 M		Project delayed from 2016		Single System Project, possible impacts	Puget Sound Area Study Team
Committed Project	2025	$13 M		Project delayed delayed from 2019		Single System Project	
Utilities have negotiated cost allocation	2018	$65-$80 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers			Single System Project	Puget Sound Area S.Team
Budgeted	2018	$4 M (SCL)	Load service, Capacity Increase, Reliability, Prevent curtailment of firm transfers, Identified in PSAST Expansion Plan	Project delayed delayed from 2018			Puget Sound Area S.Team
Budgeted	2018	$209 M	Load service and System Reliability	Project delayed delayed from 2017		Single-System Project	Puget Sound Area S.Team
Project identified as future need	2021	$66 M	Load service and System Reliability	Project delayed delayed from 2020		Single-System Project	Puget Sound Area S.Team
Budgeted	2018	$22 M	Load service, Capacity Increase, Reliability, Prevent curtailment of firm transfers, Identified in PSAST Expansion Plan	Project delayed delayed from 2017			Puget Sound Area Study Team
Project identified as future need	2021	TBD	Load growth in North County area and Reliability			Single System Project, possible impacts	
Pending Budget Approval	2017-18	$3 M	The purpose of this project is to increase system reliability and operational flexibility			Single System Project	
Budgeted	2018	$6 M	Load service, Capacity Increase, Reliability, Prevent curtailment of firm transfers, Identified in PSAST Expansion Plan	Project delayed delayed from 2017			Puget Sound Area S.Team
Budgeted	2018	$25 M	Load growth and expected local reliability deficiency in Paine Field and Everett areas requires capacity increases to meet District level of service guidelines	Project delayed delayed from 2016		Single System Project, possible impacts	Puget Sound Area Study Team
Budgeted	2018	$6 M	South County area load growth and expected reliability deficiencies. This is part of a multi-project effort to provide three 115 kV ties between BPA SnoKing and BPA Snohomish Substations.			Single System Project	
Committed	2021	$7 M	Load service and capacity needs				
Committed	2020	$25 M	Load service and capacity needs				
Committed	2017-18	$5 M	The purpose of this project is to increase system reliability and operational flexibility	New Project	No	Single System Project	
Committed	2017-18	$6 M	The purpose of this project is to increase system reliability and operational flexibility, and to replace/remove aged equipment	New Project	No	Single System Project	

Attachment B: Transmission Expansion Projects Continued

Northeastern Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Bronx-Cabinet 115 kV Rebuild	ColGrid SA	Rebuild/reconductor Bronx-Cabinet 115 kV line	Avista			Committed project
Benton-Othello 115 kV Line Upgrade	ColGrid SA	Rebuild Benton-Othello 115 kV line	Avista			Committed project
Westside 230 kV Substation rebuild and transformer upgrades	ColGrid SA	Westside 230 kV Substation rebuild and transformer upgrades	Avista			Committed project
Irvin Project - Spokane Valley Transmission Reinforcements	ColGrid SA	New Irvin-IEP 115 kV transmission line and reconductor Beacon-Boulder and Opportunity Tap 115 kV lines	Avista			Committed project
Spokane Area 230 kV Reinforcement		`	Avista			Project identified as future need
Lewiston 10 Year Plan		Second Hatwai-Lolo 230 kV line is one solution, long range study needed	Avista	BPA, IPCO, PAC		Project identified as long term need
Bell 230 kV Bus Section Breaker	ColGrid SA	Add series Bus section Breaker at Bell 230 S1-S2 to mitigate BSB failures	BPA	AVA		Plan of Service determined
Green Line Project		This project is a 100 mile extension of the MATL project to connect to the Colstrip Transmission. This project will provide access to the Mid-Columbia Hub (up to 1000 MW Capacity).	Enbridge	Colstrip Transmission Owners		Feasibility State
Wallula-McNary 230 kV line		A new 230 kV line from Wallula to the McNary (BPA)	PAC	BPA		Removed from WECC Rating Process

Eastern Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
John Day-Big Eddy 500 kV #1 Line Reconductor	ColGrid SA	Upgrade the John Day-Big Eddy 500 kV #1 Line	BPA			design in-progress
Big Eddy 230/115 kV Transformer #1 Replacement	ColGrid SA	Replace Big Eddy 230/115 kV transformer #1	BPA			plan of service determined
Celilo Terminal Replacement (PDCI Upgrade to 3220 MW)	WECC RP	Celilo Terminal Replacement (PDCI Upgrade to 3220 MW). Replace aging DC terminal and line upgrades to accommodate 3220 MW rating	BPA			design in-progress
McNary 500/230 kV Transformer #2	ColGrid SA	Add a second 500/230 kV transformer at McNary (1428 MVA) and 230 kV bus section breaker	BPA	PAC		design in-progress
Lower Valley Reinforcement (Hooper Springs)	ColGrid SA	This is a joint project with BPA, PacifiCorp, and Lower Valley Energy. PacifiCorp will construct Three Mile Knoll - a new 345/138 kV substation. The Goshen-Bridger 345 kV line will be looped into the new substation. BPA will construct Hooper Springs - a new 138/115 kV substation. Lower Valley Energy will construct a new double circuit 115 kV line (approximately 20 miles) from Hooper Springs to Lanes Creek/Valley Substations.	BPA/ PAC/ Lower Valley Electric			
Hemingway - Boardman 500 kV Line	WECC RP	In conjunction with the Gateway West project, Idaho Power is looking to extend this project from Hemingway Substation further to the north and west to the Boardman Substation.	Idaho/PAC/BPA	BPA, Avista, PAC		In WECC Rating Process

Attachment B: Transmission Expansion Projects Continued

Project Commitment Level	Scheduled Com-pletion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previ-ous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2018	$10 M				Single System Project with possible impacts	
	2018	$10 M				Single System Project with possible impacts	
	2018	$15 M				Single System Project	
	2019	$5 M				Single System Project	
	2019		Load Growth in the south Spokane area			Single System Project with possible impacts	
	10 years		Loss of Hatwai-Lolo and Hatwai-North Lewiston 230 kV lines for heavy flows to Walla Walla and Idaho				Needed
Completed	2016	$1.7 M	Local load growth and reliability			Existing Obligation Project	
			Transmission Service Requests				
	2017		Transmission Service Requests			Requested Service Project	

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previ-ous Plan	Plan cross tribal lands	Type of Project	Study Team (s)
Committed	2019	$6 M				Single System Project	
Committed	2017	$9.7 M				Single System Project	
Completed	2016	$360 M	Replace aging equipment				
Committed	2017	$31 M	Reliable Generation Interconnection				
construction on hold pending agreement	2018	$70.3 M	Load growth in eastern Idaho			Multi-system EOP with only one ColGrid participant	
phase 3	2020+	$840 M	Capacity increase		Delayed		

Attachment B: Transmission Expansion Projects Continued

Western Projects

Project Name	Regional Planning Forum	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Alvey 500 kV Shunt Reactor	ColGrid SA	Add 180 MVAR Shunt Reactor at Alvey for voltage control	BPA			Plan of service determined
North Bonneville-Troutdale 230 kV #2 Line Re-termination	ColGrid SA	This project involves re-terminating the North Bonneville-Troutdale 230 kV line into a different bus position at North Bonneville Substation	BPA			Plan of service determined
Troutdale 230kV Bus Section Breaker	ColGrid SA	Add another breaker in series with the existing bus section breaker	BPA			Plan of service determined
Castle Rock - Troutdale 500 kV Line (I-5 Corridor Reinforcement Project)	WECC RP	Construct a new 500 kV line (approx. 70 miles) from Troutdale Substation to the new Castle Rock Substation located approximately 12 miles north of Allston Substation on the Paul-Allston No.1 500 kV line.	BPA	PGE, PAC, CCP, Clark		Funding for NEPA and preliminary engineering is committed under NOS
Pearl 500 kV Breaker Addition	ColGrid SA	Construct a new Pearl 500 kV bay #6 and reterminate the Ostrander-Pearl 500 kV line into the new bay (double breaker, double bus)	BPA			
Santiam-Chemawa 230 kV Line Upgrade	ColGrid SA	Upgrade Santiam-Chemawa 230 kV line to higher capacity	BPA	PGE		Plan of service determined, delayed by land issues
Lane 230 kV Bus Section Breaker Addition		Add 230 kV Sectionalizing Breaker at Lane substation	BPA			Project under study
Longview-Lexington #2 Upgrade From 69 kV to 115 kV	ColGrid SA	Create a connection between BPA Longview and Lexington Substations through Cowlitz Substations (Mint Farm, Olive Way, 20th and Ocean Beach and West Kelso).	Cowlitz	BPA will replace 115 kV Breaker		
Longview-Lexington-Cardwell Upgrade From 69 kV to 115 kV	ColGrid SA	Create a connection between BPA Longview, Lexington, East Kelso and Cardwell Substations through Cowlitz Substations (with a connection by rebuilding old 69kV Lines for 115kV with 1272 AAC from East Kelso to West Kelso to the 115kV Line feeding Olson Rd to Lexington BKR B1466).	Cowlitz	BPA will replace 115 kV Breaker		
South Cowlitz County Project	ColGrid WST	Build a new 115 kV Line from Cowlitz' Lewis River Sub to PAC Merwin 115 kV Sub. Source Cowlitz' Ariel Sub on new Line. Reconductor 115 kV back to Cowlitz' North Woodland Sub	Cowlitz	PacifiCorp.		Cowlitz is in discussion with PAC, Agreement being finalized
Cowlitz-Lexington-Cardwell 115 kV Line		Create a connection between BPA Cowlitz, East Kelso, Lexington, and Cardwell Substations through Cowlitz Substations (with a connection by rebuilding old 69kV Lines for 115kV with 1272 AAC from 7th Avenue to East Kelso).	Cowlitz			New BKR at East Kelso, New BKR at 7th Ave
Fry 115 kV Capacitors - 100 MVAr (2×20 MVARs, 2×30MVARs)	ColGrid SA	2x20 MVARs and 2x30 MVARs	PAC			
Snow Goose 500/230 kV Transformer (On Captain Jack - KFalls Cogen 500 kV Line)	ColGrid SA	New 500 kV substation tapping PAC's Captain Jack to Klamath Co-Gen 500 kV line. The 230 kV line construction will included looping the existing Klamath Falls to J.C. Boyle 230 kV line into the new substation.	PAC	BPA		Under Construction
Lookingglass Substation		New Lookingglass Substation on Dixonville-Reston 230 kV line	PAC			
Table Mountain 500/230 kV Transformer (On Dixonville - Meridian 500 kV Line)	ColGrid SA	New 500/230 kV substation tapping PAC's Meridian to Dixonville 500 kV line. 230 kV line construction will included looping the existing Grants Pass to Meridian 230 kV line into the new substation as well as construction of a new 230 kV transmission line for the new substation to the existing Grants Pass 230 kV Substation.	PAC	BPA		Preliminary Study
Troutdale East - Blue Lake - Gresham 230 kV Line (Blue Lake/Gresham 230kV Project)	ColGrid SA	Construct a transmission line from Blue Lake Substation (Troutdale, Oregon) to Gresham Substation (Gresham, Oregon). This project requires 4.2 miles of new 230 kV transmission line. Rebuild the existing Blue Lake - Troutdale BPA 230 kV circuit to a double circuit steel monopole line and construct a second circuit from Blue Lake to Troutdale.	PGE	BPA		Plan of service determined
Blue Lake/Gresham Phase II Project	ColGrid SA	Install a second bulk power transformer at Blue Lake substation. Construct a new 4-position 115kV ring bus. Construct two 115kV lines, one to Tabor and one to McGill. Decommission Linneman substation.	PGE	BPA, PAC		Preliminary Study
Horizon Phase II Project	ColGrid SA	Install a second bulk power transformer at Horizon substation. Install a new 4.4 mile 230 kV line section from Horizon substation to Springville Junction. The new line segment will tie into the existing St Marys-Trojan 230 kV circuit, creating a Horizon-St Marys-Trojan 230 kV circuit	PGE			Plan of service
Harborton Reliability Project	ColGrid SA - next year	Rebuild the 115kV yard to a breaker-and-one-half configuration. Install a new 230kV yard, bulk power transformer, and 115kV cap bank. Loop the existing Rivergate-Trojan 230kV and St Marys-Trojan 230kV lines into Harborton. Re-purpose an existing 115kV line to create a Harborton-Horizon 230kV line. Reconfigure the St Marys-Wacker 115kV line to create a Harborton-Wacker 115kV line and a St Marys-Cedar Hills 115kV line.	PGE			Plan of service determined
New Industrial Customer		Construct new 230 kV line from BPA Longview to Kalama. To server new industrial load	Cowlitz	BPA		Proposed new load

Attachment B: Transmission Expansion Projects Continued

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team (s)
Completed	2016	$10 M					
Completed	2016	$4M	Local load growth			Single System Project	
Committed	2018	$2 M	Reliability and load growth			Single System Project	
Record of Decision Depends upon NEPA	2023	$ 772 M	Transmission Service Requests			Requested Service Project	I-5 Corridor Regional Planning Study Team
Completed	2016	$2.1 M	Local load growth			Single System Project, possible impacts	
Committed	2017	$1.0 M	local load service			Single System Project, possible impacts	
Funding approved by sponsor	2017	$1.6 M					
Funding approved by sponsor	2014-17	$4.9 M	Reliability and load growth			Single System Project	
Funding approved by sponsor	2015-17	$10.1 M	Reliability and load growth			Single System Project	
	2018	$7.7 M	Local load growth and needed voltage/ reliability support			Single System Project, possible impacts	
Funding approved by sponsor	2014-15		Reliability and load growth			Single System Project	
	In-Service						
	2017					Single System Project, possible impacts	
	Project not in our 10-yr plan		Reliability and load growth			Single System Project	
Under study	2019					Single System Project, possible impacts	
Committed	2018		Reliability			External Project	
Conceptual project for future need	2022		Reliability	New Project		External Project	
Committed	2018		Reliability and load growth			Single System Project	
Committed	2021		Reliability	New Project		External Project	
Customer high priority project. Proposal only at this time	2020	$30 M	To serve new 400 MW Load	New Project		Single System Project	

Attachment B: Transmission Expansion Projects Continued

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