2019 Biennial Transmission Expansion Plan (BTEP)

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Acknowledgements

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Cowlitz County PUD
Douglas County PUD
Grant County PUD
Puget Sound Energy
Seattle City Light
Snohomish County PUD
Tacoma Power

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Executive Summary

The 2019 BTEP describes the details of twelve major studies and support services that were provided in the most recent planning cycle as summarized below:

1. Area Coordinator: An ongoing effort to develop base cases for the Northwest region.
2. Two System Assessments & Associated Sensitivity Studies: An annual study that focuses on potential reliability issues and identifies the regional needs (Needs Statement) in ColumbiaGrid's footprint. Special studies were conducted annually as needed. The scope of these sensitivity studies can be varied depending on input from planning participants.
3. Transient Stability: An annual study that focuses on dynamic performance of the Northwest transmission system.
4. Order 1000 Activities: These include the regional and interregional activities that are governed by ColumbiaGrid's Order 1000 Functional Agreement.
5. Alcoa Study Team: A study group that was formed to evaluate potential impacts from a major load shutdown in Chelan PUD's service area.
6. Quincy Study Team: A study group that was formed to evaluate potential impacts from higher than expected load forecast in Grant PUD's service area.
7. Physical Security Third-Party Review: An independent review of the Physical Security assessment of major transmission substations. It is also an effort to support member compliance with the NERC CIP-014 standard.
8. Relay Performance during Power Swings: A new study that was conducted to identify potential operation of protective relays as well as supporting ColumbiaGrid's members in their compliance with the NERC PRC-026 standard.
9. Model Validation: A study to validate the accuracy of transmission planning models in compliance with the NERC MOD-033 standard.
10. Geomagnetic Disturbance: A new study to identify power transformers that could experience high Geomagnetic Induced Current (GIC) flow during a geomagnetic event which is required by the NERC TPL-007-1 standard.
11. Economic Planning Study: An annual study to assess future system conditions using production cost simulation.

A summary of these activities are shown in Figure 1 as well as being discussed in this document.

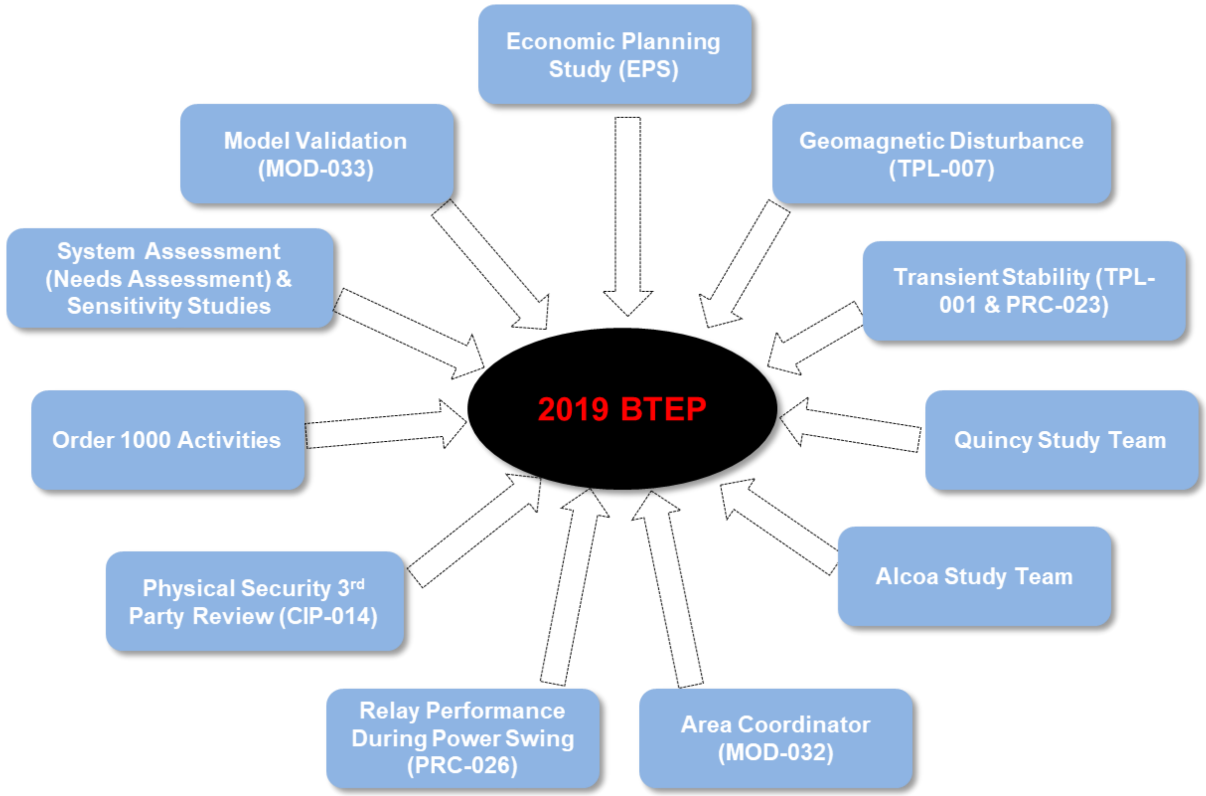

Figure 1: Components of the 2019 Biennial transmission Expansion Plan (2019 BTEP)

It should be noted that the frequency at which these activities are conducted varies. While most studies were performed annually, some activities required more time to be completed. A summary of the frequency and duration of these activities is shown Table 1.

Table 1: Major activities that were conducted in the 2017-2018 planning cycle

No	Activity	2017	2018
1	System Assessment	Yes	Yes
2	Sensitivity Study: High Renewable	Yes	No
3	Sensitivity Study: N-1-1	Yes	Yes
4	Model Validation (MOD-033)	Yes (Span 2 years)	
5	Economic Planning Study (EPS)	Yes	Yes
6	Geomagnetic Disturbance (GMD)	Yes (Span 2 years)	
7	Transient Stability	Yes	Yes
8	Quincy Study Team	No	Yes
9	Alcoa Study Team	Yes	No
10	Area Coordinator	Yes	Yes
11	Relay Performance During Power Swing (PRC-026)	No	Yes
12	Physical Security 3rd Party Review	Yes	No

System Assessment

The System Assessment was conducted in each year of this planning cycle. The main objective of the System Assessment is to identify potential needs for additional system reinforcements that could be driven by various factors such as load growth, power transfers, or other changes in system conditions. Any potential need identified in the System Assessment is documented in a "Needs Statement". Each System Assessment analyzed system conditions in the ten-year planning horizon from the year it was conducted. Generally, the System Assessment in year-one identifies the problem areas and potential needs whereas, the System Assessment in year-two refines and re-examines the system's problem areas and needs. The technical studies that were conducted in both System Assessments include:

- Power flow analyses
- Stability assessments
- Angle differences identifications

ColumbiaGrid produces two reports that outline the details and summary of the System Assessments which are: 1) the Study Plan and 2) System Assessment Study. These reports are posted on ColumbiaGrid's public website at: https://columbiagrid.org/basecases-results-overview.cfm

Since the main objective of the System Assessment is to identify "regional" needs, the System Assessment report has focused its reporting on potential issues in the "Joint Areas of Concern", which can be defined as potential needs that involve multiple ColumbiaGrid parties. These areas are identified when multiple planning parties had outages that caused overloads and/or had facilities that overloaded as a result of such outages. ColumbiaGrid organizes study teams as necessary to resolve these system deficiencies. If a problem did not involve multiple parties, it was considered to be a single-system issue and remained the responsibility of that individual party. Generally, the identified Joint Areas of Concern were reported in three major categories as shown below:

- Resolved: The problems are no longer identified in the latest System Assessment
- Recurring: The problems that were identified in previous years reappear in the latest System Assessment
- New: Newly identified problems.

Key Conclusions and Observations

The 2017 and 2018 System Assessments identified eleven and eight Joint Areas of Concern, respectively. However, the issues in these areas are unlikely to be classified as regional needs since they are mostly local problems where mitigation plans have already been developed or they still require further evaluation by the affected parties. The Joint Areas of Concerns are shown in Table 2 and Figure 2.

Table 2: Joint Areas of Concern that were identified in 2017 SA and 2018 SA

No	Area of Concern in 2018 System Assessment	Identified in 2017 SA	Identified in 2018 SA	Note/Category
*	Yakima/Wanapum	YES	NO	Resolved: Load forecast adjustment and the modeling updates alleviated these issues
*	Oregon Coast	YES	NO	Resolved: A reduced load forecast in 2018 alleviated the issues
*	Portland	YES	NO	Resolved: The modeling of several mitigation plans, including the Blue Lake/Gresham and the Horizon projects allviated the issues
*	Sandpoint, Idaho	YES	NO	Resolved: The modeling of the Bronx - Sand Point 115 kV line reconductoiring and other projects have alleviated the issue in this area
1	Bend	YES	YES	Recurring
2	Centralia	YES	YES	Recurring
3	Olympic Peninsula	YES	YES	Recurring
4	Othello	YES	YES	Recurring
5	Palouse	YES	YES	Recurring
6	Puget Sound	YES	YES	Recurring
7	Spokane	YES	YES	Recurring
8	Mid Columbia	NO	YES	New

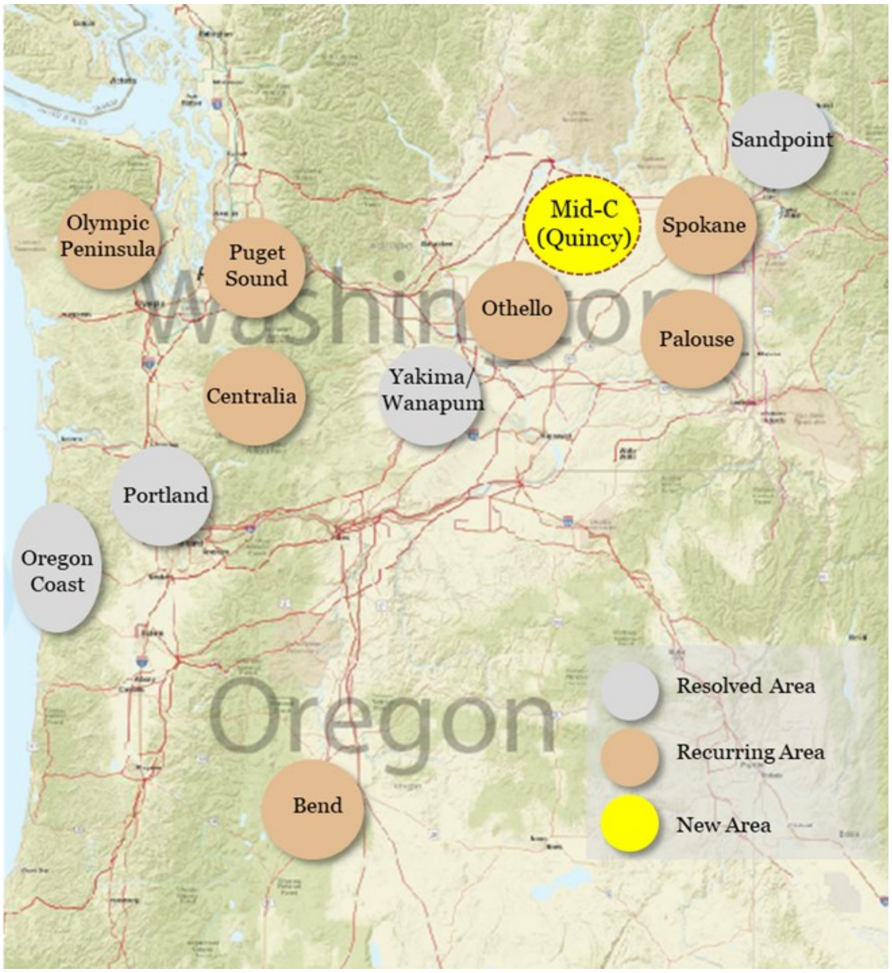

Figure 2: Approximate locations of Joint Areas of Concern

THE TEN YEAR PLAN: The culmination of all of the two-year planning cycle is the biennial ten-year transmission expansion plan (2019 BTEP):

No	Project Name	Region	Description	Sponsor	Scheduled Completion	Cost Estimate
1	Alderton 230/115 kV Transformer in Pierce County	Puget Sound	A new 230/115 kV transformer at Alderton Substation in central Pierce County with a new 230 kV line from White River.	PSE	2018	$45 M
2	Benton-Othello 115 kV Line Upgrade	Northeastern	Rebuild Benton-Othello 115 kV line	Avista	5+ years	$10 M
3	Berrydale 230 kV Transformer Addition	Puget Sound	Install second 230/115 kV transformer at Berrydale Substation.	PSE	2025+	$8 - $15 M
4	Beverly Park 230/115 kV Transformer	Puget Sound	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	2018	$25 M
5	Big Eddy 230/115 kV Transformer #1 Replacement	Eastern	Replace Big Eddy 230/115 kV transformer #1	BPA	2020	$9.7 M
6	Bothell-Snoking 230 kV Double Circuit Line Reconductor	Puget Sound	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	2018	$4 M (SCL)
7	Christopher 230 kV Substation	Puget Sound	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	2025+	$30 M
8	Columbia 230 kV Bus Section Breaker	Central Washington	Add a series bus section breaker at Columbia 230 kV substation	BPA	2018	$2.0 M
9	Cowlitz-Lexington-Cardwell 115 kV Line	Western	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	2020	
10	Delridge-Duwamish 230 kV Line Reconductor	Puget Sound	Reconductor Delridge - Duwamish 230 kV Line with high temperature low sag conductor	SCL	2018	$6 M

TEN YEAR PLAN (CONT)

No	Project Name	Region	Description	Sponsor	Scheduled Completion	Cost Estimate
11	Denny - Broad and Massachusetts - Union - Broad 115 kV Series Inductors	Puget Sound	Add 6 ohm inductors on Denny - Broad and Massachusetts - Union - Broad 115 kV underground cables. 115kV Capacitor Bank at Broad Substation.	SCL	2018	$22 M
12	Denny Substation (Phase 1)	Puget Sound	New 225 MVA substation in the north downtown Seattle area. Loop existing East Pine-Broad 115 kV line.	SCL	2018	$209 M
13	East King County Transformer Capacity (Lake Tradition)	Puget Sound	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	2025+	$15-$30 M
14	Eastside Project: Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot Line Rebuilt to 230 kV	Puget Sound	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	2020	$110 M
15	Irvin Project - Spokane Valley Transmission Reinforcements	Northeastern	New Irvin-IEP 115 kV transmission line and reconductor Beacon-Boulder and Opportunity Tap 115 kV lines	Avista	2020	$5 M
16	John Day-Big Eddy 500 kV #1 Line Reconductor	Eastern	Upgrade the John Day-Big Eddy 500 kV #1 Line	BPA	2019	$6 M
17	Lewiston 10 Year Plan	Northeastern	Second Hatwai-Lolo 230 kV line is one solution, long range study needed	Avista	10+ years	
18	Lone Pine Substation	Central Washington	Build a new 115-kV substation in between the Chelan Falls Substation and Brays Substation on the existing 115-kV line.	DOPD	2020	$3 M
19	Longview-Kalama 230 kV line	Western	Construct new 230 kV line from BPA Longview to Kalama.	Cowlitz	2020	$30 M
20	Lower Valley Reinforcement (Hooper Springs)	Eastern	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	2019	$70.3 M

TEN YEAR PLAN (CONT)

No	Project Name	Region	Description	Sponsor	Scheduled Completion	Cost Estimate
21	Monroe-Novelty 230 kV line Upgrade	Puget Sound	Increase capacity of Monroe-Novelty 230 kV line	BPA	2020	$2.9 M
22	North Stanwood to Camano 115kV Line	Puget Sound	Build a new, second 115kV line from Stanwood to Camano	Snohomish County PUD	2020	$6M
23	North Stanwood to Camano 115kV Line	Puget Sound	Rebuild existing Stanwood-Camano 115kV line	Snohomish County PUD	2021	$3M
24	Pearl Cushman Upgrade	Puget Sound	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	2017-18	$6 M
25	PSE Bellingham Substation Rebuild	Puget Sound	Construct a new breaker and a half 115 kV substation	PSE	2019	$20 M
26	Rapids-Columbia 230 kV Line and Columbia Terminal	Central Washington	Build new Rapids-Columbia 230 kV line	Douglas, Grant, Chelan, BPA	2019	$23.25 M
27	Raver 500/230 kV transformer and a 230 kV line to Covington Substation.	Puget Sound	Add a 500/230 kV transformer at Raver and a 230 kV terminal at Raver for a Raver-Covington 230 kV line.	BPA	2020	$60 M
28	Rocky Ford - Dover 115 kV Line	Central Washington	Construct 115 kV Rocky Ford-Dover 115 kV line	Grant County PUD	2019	$5 M
29	Rocky Reach-Chelan #1 115 kV Retermination	Central Washington	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	2022	
30	Santiam-Chemawa 230 kV Line Upgrade	Western	Upgrade Santiam-Chemawa 230 kV line to higher capacity	BPA	2019	$1.0 M
31	Sedro-Woolley-Bellingham #4 115 kV line	Puget Sound	Reconductoring Sedro-Woolley-Bellingham #4 115 kV line	PSE	2021	$14 M
32	South Cowlitz County Project	Western	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	2019	$7.7 M

TEN YEAR PLAN (CONT)*

* Numbering 33-38 intentionally skipped consistent with 2018 System Assessment numbering of projects.

39	Troutdale 230kV Bus Section Breaker	Western	Add another breaker in series with the existing bus section breaker	BPA	2018	$2 M
40	Turner-Woods Creek 115 kV Line	Puget Sound	Build a new Turner-Woods Creek 115 kV line for new distribution substations	Snohomish County PUD	2024	$25 M
41	Upgrade Denny Substation Transmission	Puget Sound	New transmission line from Massachusetts Substation to Denny Substation (built at 230 kV, operated at 115 kV).	SCL	2021	$66 M
42	Veedol Substation	Central Washington	Build a new 115-kV substation in between Eastmont Substation and Pangborn Substation on the existing 115-kV line.	DOPD	2017	$4 M
43	West Kitsap Transmission Project Phase II	Olympic Peninsula	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	2021+	
44	White River Bus Improvements	Puget Sound	Add 2nd 115 kV Bus Section breaker at White River (230 kV bus completed)	PSE	2020+	$0.6 M
45	Woodland-Gravelly Lake 115 kV Line	Puget Sound	Add new Woodland-Gravelly Lake 115 kV line	PSE	2022+	$13 M

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Introduction

ColumbiaGrid was formed by seven founding members in 2006 with an eighth member joining later, to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. It operates a biennial transmission planning process that is governed by the Planning and Expansion Functional Agreement (PEFA) and Order 1000 planning agreement. A high level summary of key contents of the ColumbiaGrid Planning Process is shown in Figure 3.

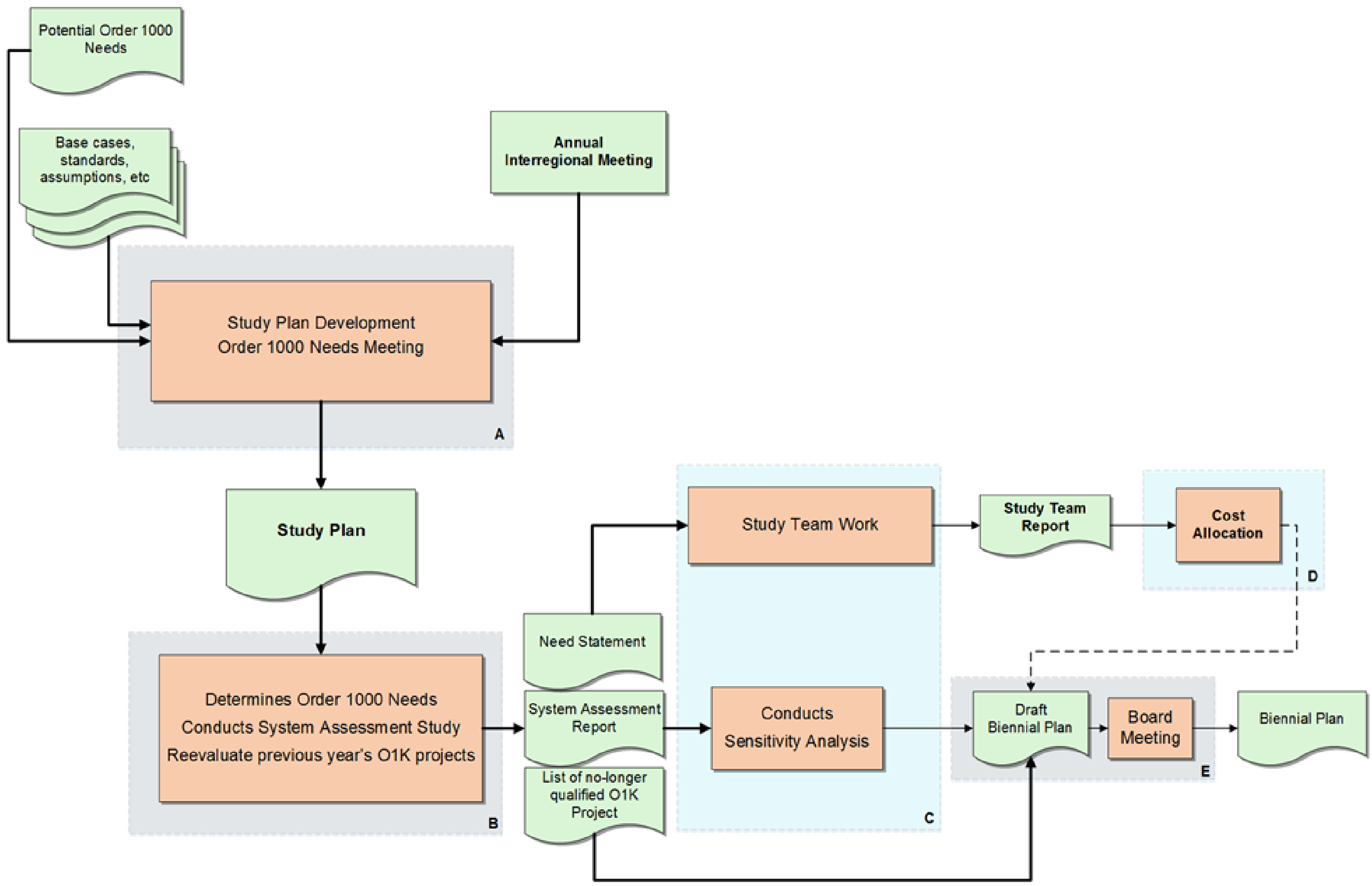


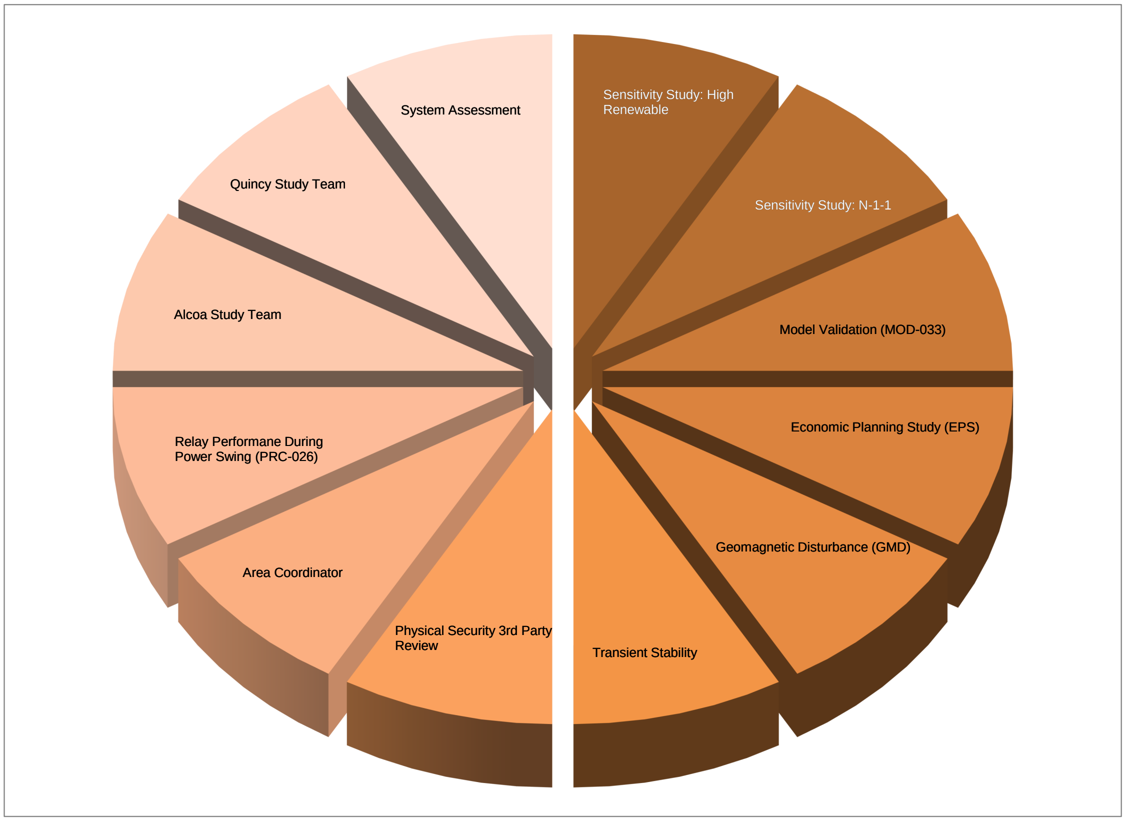
Figure 3: Overview of ColumbiaGrid Planning Process

As illustrated in the diagram, the Biennial Transmission Expansion Plan (BTEP) is one of the key products from this planning process. This document provides a summary of planning activities in each planning cycle. Generally, the contents of this document include:

- A list of planning activities that occurred in each planning cycle
- An overview of the scope of each activity
- Major issues, findings, or key components
- Key conclusions or outcome from each activity

This 2019 Biennial Transmission Expansion Plan (BTEP) provides a summary and details of ColumbiaGrid planning activities that occurred during the 2017-2018 planning cycle. In these two years, twelve major studies and support services were provided for seven different service programs. These activities are summarized below:

- Two System Assessments (SAs) and associated sensitivity studies were performed in 2017 and 2018. The main goal of each SA is to identify needs for additional system reinforcements (Needs Statement).
- Activities in support of the FERC Order 1000 Functional Agreement were conducted throughout 2017 and 2018. These activities include both regional and interregional efforts such as identification of Order 1000 needs, participation in the Annual Interregional Coordination Meeting ((AICM), and Interregional Transmission Project (ITP) evaluation.
- Four technical studies were conducted to support ColumbiaGrid members' NERC standard compliance. These include Physical Security 3rd party review (CIP-014-1), Steady State and Dynamic Model Validation (MOD-033), Geomagnetic Disturbance (TPL-007-1), and Relay Performance During Power Swing (PRC-026).
- Two study teams were formed to analyze potential issues and develop mitigation plans in the Mid-Columbia area. These included the Alcoa and Quincy Study Teams.
- Transient stability was performed each year to analyze the dynamic performance of Northwest transmission system and to support dynamic base case development process by ColumbiaGrid.
- Economic planning studies were performed to assess future system conditions using production cost simulation.
- Area Coordinator role which supports base case development process was performed in both 2017 and 2018.



Area Coordinator & Base Case Development

WECC's base case building process requires frequent data submittals by Planning Coordinators (PCs) to represent the transmission system that they are responsible for. These cases built by WECC are intended to be used for studies to comply with standards or other scenario based study work. In the Northwest, ColumbiaGrid compiles and submits this data on the PCs' behalf.

In a typical year WECC requests data for and builds eleven cases. The requests are spread across the year and consist of an initial data compiling stage and a comments stage where additional corrections can be made. ColumbiaGrid works with Northwest PCs and performs the Area Coordinator role for the Pacific Northwest Region (Area 40). Among these PCs are ColumbiaGrid members and neighboring entities such as Portland General Electric (PGE) and PacifiCorp West (PACW).

In addition to base case development activities that have been done as part of Area Coordinator, each year ColumibaGrid also developed additional base cases and dynamic data that can be used by its members. Basically, these cases can be used in a variety of studies such as the CIP-014, PRC-026, and TPL studies. In 2017, nine base cases were created as summarized in Table 3 below.

Table 3: Base cases that ColumbiaGrid issued in 2017

No	Study Year	Study Case	Purpose
1	2019	Near-Term Heavy Summer	Member Use
2	2019	Near-Term Heavy Winter	Member Use
3	2019	Short- Term Light Load	System Assessment Studies & Member Use
4	2022	5 yr Heavy Summer	Member Use
5	2022	5 yr Heavy Winter	System Assessment Studies & Member Use
6	2023	5 yr Heavy Summer	Member Use
7	2023	5 yr Heavy Winter	Member Use
8	2028	Long-Term Heavy Summer	System Assessment Studies & Member Use
9	2028	Long-Term Heavy Winter	System Assessment Studies & Member Use

The table above also shows that four cases were created for the five-year scenarios due to different interpretations of the standard. This resulted in the need for multiple versions of a five-year case in 2017 as well as 2018 as shown in Table 4.

Table 4: Base cases that ColumbiaGrid issued in 2018

No	Study Year	Study Case	Purpose
1	2019	Near-Term Heavy Summer	Member Use
2	2019	Near-Term Heavy Winter	Member Use
3	2020	Near-Term Heavy Summer	Member Use
4	2020	Near-Term Heavy Winter	Member Use
5	2021	Short- Term Light Load	System Assessment Studies & Member Use
6	2023	5 yr Heavy Summer	System Assessment Studies & Member Use
7	2023	5 yr Heavy Winter	Member Use
8	2024	5 yr Heavy Summer	Member Use
9	2024	5 yr Heavy Winter	Member Use
10	2028	Long-Term Heavy Summer	System Assessment Studies & Member Use
11	2028	Long-Term Heavy Winter	System Assessment Studies & Member Use

System Assessments

Among these activities, the 2017 and 2018 System Assessments identified a number of Joint Areas of Concern as shown in Table 5. None of these issues are considered to be regional needs: subsequent analysis showed they are mainly local problems and some of them can be mitigated by future transmission reinforcements that were proposed in previous years.

Table 5: A summary of the identified Joint Areas of Concern

No	Area of Concern in 2018 System Assessment	Identified in		Note/Category
		2017 SA	2018 SA	
*	Yakima/Wanapum	YES	NO	Resolved: Load Projection & Modeling Correction Update
*	Oregon Coast	YES	NO	Resolved: Load Projection Update
*	Portland	YES	NO	Resolved: Mitigation Projects Modeled
*	Sandpoint, Idaho	YES	NO	Resolved: Mitigation Project Modeled
1	Bend	YES	YES	Recurring
2	Centralia	YES	YES	Recurring
3	Olympic Peninsula	YES	YES	Recurring
4	Othello	YES	YES	Recurring
5	Palouse	YES	YES	Recurring
6	Puget Sound	YES	YES	Recurring
7	Spokane	YES	YES	Recurring
8	Mid-Columbia	NO	YES	New

By comparing the Joint Areas of Concerns that were identified in 2017 and 2018, a reduction in the number of identified areas was driven by several factors; such as a slight rotation of base cases used in each SA increased ColumbiaGrid's capability to evaluate more scenarios. However, this may result in an identified issue from a previous year to not be identified in the most recent System Assessment and vice versa. A summary of the scenarios that were used in 2017 and 2018 SA is shown in Table 6.

Table 6: Summary of scenarios that were conducted in each System Assessment

Time Fame	Scenario	2017 SA	2018 SA
Near Term	Light Summer	Yes	No
	Light Spring	No	Yes
Five Year	Heavy Summer	No	Yes
	Heavy Winter	Yes	No
Ten Year	Heavy Summer	Yes	Yes
	Heavy Winter	Yes	Yes

Implementation of new projects: The assumptions in the 2018 System Assessment included several new projects expected to be in-service that mitigated a number of previously identified reliability issues. Table 7 compiles a list of the new transmission projects that were modeled in the 2018 System Assessment. Furthermore, a complete list of transmission projects in the ten year plan is summarized in the Executive Summary.

Pink highlighted projects were included in the 2017 BTEP and are now modeled in the base cases, as shown in Table 7 below. Based on feedback that was received in 2017, a number of findings that were determined to be invalid were excluded from the 2018 System Assessment. This reduced the number of reliability issues.

Table 7: Summary of new Transmission Projects that were modeled in the 2018 System Assessment

No	Committed Projects Included in All Cases	Sponsor	Expected In-Serive	Modeled in the case			
				2021 LSP	2023 HS	2028 HS	2028 HW
1	Troutdale East - Blue Lake - Gresham 230 kV Line (Blue Lake/Gresham 230kV Project)	Portland General Electric	2018	√	√	√	√
2	Horizon Phase II Project	Portland General Electric	2018	√	√	√	√
3	Alderton 230/115 kV transformer in Pierce County	Puget Sound Energy	2018	√	√	√	√
4	Eastside Project: Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot line rebuild to 230 kV	Puget Sound Energy	2020	√	√	√	√
5	Irvin Project - Spokane Valley Transmission Reinforcements	Avista	2020		√	√	√
6	Benton-Othello 115 kV Line Upgrade	Avista			√	√	√
7	John Day-Big Eddy 500 kV #1 Line Reconductor	Bonneville Power	2019		√	√	√
8	Raver 500/230 kV transformer and a 230 kV line to Covington Substation.	Bonneville Power	2020		√	√	√
9	Big Eddy 230/115 kV Transformer #1 Replacement	Bonneville Power	2020		√	√	√
10	Lower Valley Reinforcement (Hooper Springs)	Bonneville Power	2019		√	√	√
11	Santiam-Chemawa 230 kV Line Upgrade	Bonneville Power	2019		√	√	√
12	Troutdale 230kV Bus Section Breaker	Bonneville Power	2018		√	√	√
13	South Cowlitz County Project	Cowlitz County PUD	2019		√	√	√
14	Rapids-Columbia 230 kV Line and Columbia Terminal	Douglas County PUD	2019		√	√	√
15	Rocky Ford - Dover 115 kV Line	Grant County PUD	2019		√	√	√
16	Vantage-Pomona Heights 230 kV Line (Short Route)	PacifiCorp	2019		√	√	√
17	Sam's Valley 500/230 kV Transformer (On Dixonville - Meridian 500 kV Line)	PacifiCorp	2019		√	√	√
18	Blue Lake/Gresham Phase II Project	Portland General Electric	2020		√	√	√

Table 7: Summary of new Transmission Projects that were modeled in the 2018 System Assessment (Cont.)

No	Committed Projects Included in All Cases	Sponsor	Expected In-Serive	Modeled in the case			
				2021 LSP	2023 HS	2028 HS	2028 HW
19	Harborton Reliability Project	Portland General Electric	2020		√	√	√
20	Woodland-Gravelly Lake 115 kV Line	Puget Sound Energy			√	√	√
21	Bothell-Snoking 230 kV Double Circuit Line Reconductor	Seattle City Light	2018		√	√	√
22	Denny Substation (Phase 1)	Seattle City Light	2018		√	√	√
23	Upgrade Denny Substation Transmission	Seattle City Light	2021		√	√	√
24	Denny - Broad and Massachusetts - Union - Broad 115 kV Series Inductors	Seattle City Light	2018		√	√	√
25	Delridge-Duwamish 230 kV Line Reconductor	Seattle City Light	2018		√	√	√
26	Beverly Park 230/115 kV Transformer	Snohomish County PUD	2018		√	√	√
27	Swamp Creek 115 kV Switching Station	Snohomish County PUD	2018		√	√	√
28	Pearl Cushman Upgrade	Tacoma Power	2018		√	√	√
29	Turner-Woods Creek 115 kV Line	Snohomish County PUD	2024			√	√

New load forecast: While the total load forecasts for the entire Northwest area are similar in 2017 and 2018, significant changes in load forecast were observed in some local areas. Figures 4 and 5 on the next page provide the summary of the overall and local load forecast comparisons. These changes contributed to the identification of a new Joint Area of Concern in 2018.

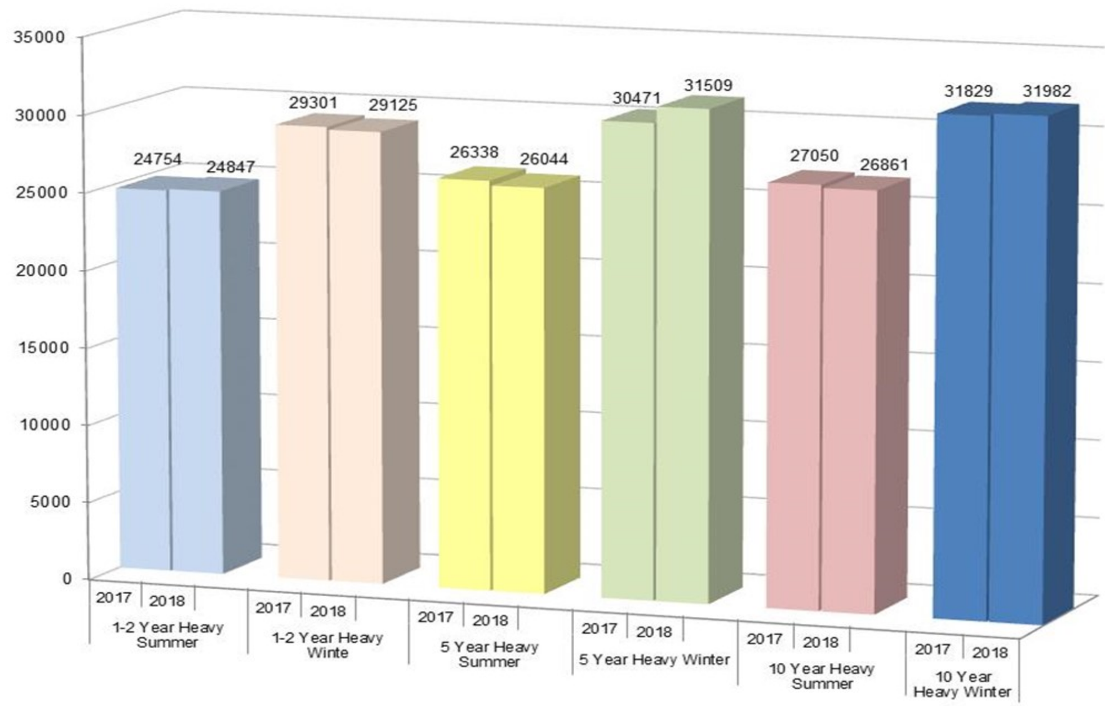


Figure 4: Area load forecasts that were used in 2017 SA and 2018 SA

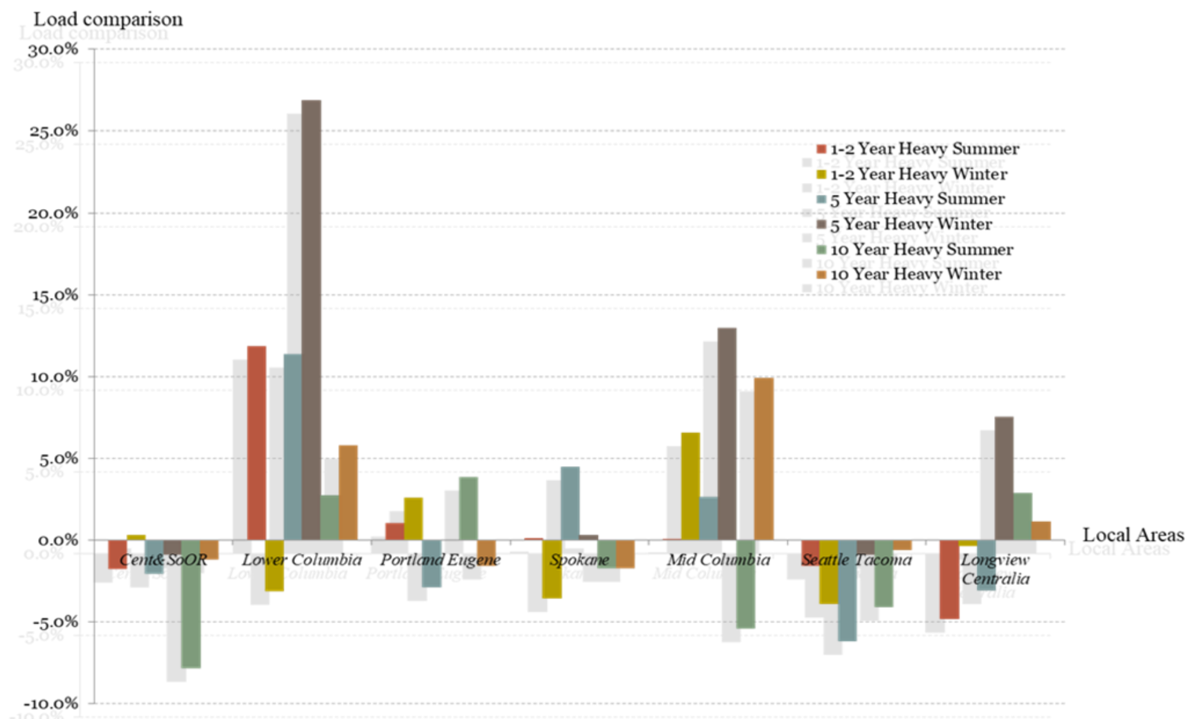


Figure 5: Comparison of local areas load forecasted between 2017 SA and 2018 SA

SENSITIVITY STUDIES

The sensitivity studies are conducted as part of the annual study program as needed. The scope of these studies can be varied and depends on input from the planning participants. In 2017, two sensitivity studies, which included the N-1-1 Outage and High Renewable Studies, were performed. In 2018, ColumbiaGrid combined the High Renewable Study with the Economic Planning Study. It resulted in only one sensitivity study in 2018. The following provides additional details of the sensitivities that were studied in 2017 and 2018.

N-1-1 Outage Study

This N-1-1 study simulates the loss of a first element, followed by system adjustment, and then compounded by the loss of a second element. In general, this study involves the simulation and analysis of study results that are created by the combination of two overlapping single contingencies. Without implementation of techniques or special software to reduce the number of potential contingency combinations, this task may require significant manpower and resources to complete.

ColumbiaGrid has focused on developing techniques and software tools to address this challenge. A pared down list of contingencies is produced by using various tools and methods to evaluate the validity of the N-1-1 contingency combination. This method was used to study the 10 year heavy summer and 10 year heavy winter cases. The results were then processed to identify N-1-1 combinations that resulted in 1) a more severe overload than the N-1 outages by themselves, 2) unsolved combinations, and 3) whether the outage combination involved multiple data owners. At this stage, voltage issues were not tracked. This methodology assumes adequate voltage support adjustments are available after the first contingency. The contingency list, results, and summaries were posted for participants to review to determine if any additional study or action is needed to address the identified issues.

The primary change between 2017 and 2018 was the additional processing of the cases after the initial results to minimize invalid issues found in earlier N-1-1 studies. This most often included preventing shunts and static var compensators (svcs) outside the area from oscillating for outage combinations outside their area, adjusting generators on the verge of overloading elements in the case from creating overloads for nearly every monitored N-1-1 combination, and preventing weak areas of the system from going unstable for nearly every N-1-1 combination. This resulted in a more concise and valid list of identified issues for members to review. Table 8 below summarizes the results.

Table 8: High level summary of the N-1-1 studies

System Assessment	Case	Total N-1-1 Overloads	Total Primary Outages Resulting in N-1-1 Overloads	Total Unsolved Outages
2017	2027 Heavy Summer	25,852	862	1,085
2017	2027 Heavy Winter	907	116	39,343
2018	2028 Heavy Summer	1,470	190	3,009
2018	2028 Heavy Winter	11,621	124	7,700

High Renewable Study

This sensitivity study was performed in 2017. This study focused on analyzing potential impacts due to generation portfolio changes with large increases of renewable generation and lower usage of fuel based generation across the west. This sensitivity evaluated the long term system reliability impacts in the Northwest due to high renewable generation across the west and had a secondary goal of becoming more familiar with a feature in the GridView software that exports data from production cost models into power flow cases. Basically, the scope of this study includes:

- Analyze the hourly results from the Production Cost Simulation for the entire year
- Determine several hours where potential new reliability problems may occur (for example, the conditions that are not part of the typical reliability analysis)
- Create the power flow base cases that mimic the selected hours
- Perform power flow analysis to identify potential reliability problems for each hour

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. A 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 and, after solving the case, the System Assessment contingency list was run to evaluate the system performance. A high-level summary of the system conditions at this snapshot is shown in Table 9.

Table 9: Summary of key System Conditions in the 2017 High Renewable Study

Component	Value (MW)
Northwest Load	18,867
Northwest Generation	18,566
Northwest - BC Hydro Flow	-1,853
Idaho - Northwest Flow	-524
Montana - Northwest Flow	438
PDCI Flow	100
COI Flow	344
North of John Day Flow	2,309
South of Allston Flow	100
West of Cascades North Flow	3,687
West of Cascades South Flow	3,866
West of Hatwai Flow	-83

Overall, the study results showed few overloads and unsolved outages. This was 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 were sent to members to be looked at to determine if the voltage control issues attributed to the new issues.

ORDER 1000 ACTIVITIES

The Order 1000 Functional Agreement requires certain tasks to be conducted as part of ColumbiaGrid planning activities. These include annual or "performed as needed" activities once certain criteria are met. It also includes requirements that pertain to regional or interregional coordination. Below are some of the annual Order 1000 activities that ColumbiaGrid has been involved in this planning cycle:

- Order 1000 Needs Meetings: As part of ColumbiaGrid Order 1000 regional planning activities, these meetings were held in February of each year to collect and discuss suggestions for potential Order 1000 needs that may result in Order 1000 projects.
- Reevaluation of Order 1000 Projects: This part of Order 1000 regional planning requires ColumbiaGrid to reevaluate Order 1000 projects that were identified in a prior BTEP.
- Annual Interregional Coordination Meetings: This Order 1000 Interregional requirement requires ColumbiaGrid to participate in a discussion regarding the regional needs and other planning activities of the western planning regions at least once a year.
- Interregional Transmission Project (ITP) evaluation: Order 1000 also allows the proponents of an ITP to submit their proposals to be evaluated by the Relevant Planning Regions.

Order 1000 Needs Meetings

In each year of the planning cycle, interested parties may submit suggestions for Order 1000 Potential Needs to ColumbiaGrid during the first two calendar months of the year. In addition, Order 1000 Needs Meetings were held on February 9, 2017 and Feb 8, 2018 to discuss Order 1000 Potential Needs with the interested parties. However, ColumbiaGrid did not receive any Order 1000 Potential Needs suggestions during the past two years. Consequently, the Needs Assessments were conducted according to the scope of the annual system assessments as described in the Study Plan.

Reevaluation of Order 1000 Projects

Since there were no Order 1000 Projects included in the prior BTEP, this task was not required to be performed.

Annual Interregional Coordination Meetings

The purpose of the Annual Interregional Coordination Meeting (AICM) is to discuss interregional topics which may include each Planning Region's most recent Annual Interregional Information, identification and preliminary discussion of potential interregional solutions that may meet regional transmission needs in two or more Planning Regions, and updates of the status of Interregional Transmission Projects (ITPs) being evaluated. During the past two years, ColumbiaGrid hosted the 2017 AICM on February 23, 2017 in Portland, Oregon and participated in the meeting that was hosted by the California Independent System Operator (CAISO) in 2018.

Interregional Transmission Projects

Each two-year cycle of ColumbiaGrid's Planning Process includes a submission window in which proponents may submit a proposed ITP to be reviewed by the Relevant Planning Regions no later than March 31st of any even-numbered calendar year. Over the last two years, ColumbiaGrid has been involved in the review of two sets of ITP submittals as summarized below.

ITP's submitted in 2016

Six (6) proposed Interregional Transmission Projects were submitted for joint evaluation by the Western Planning Regions. These proposed projects are shown in Table 10.

Table 10: ITPs that were submitted to the 2016 submittal window

No	ITP Name	Submitted to	Project Proponent
1	Cross-Tie Transmission Project	CAISO, WestConnect, NTTG	TransCanyon, LLC
2	HVDC Conversion Project	CAISO, WestConnect	San Diego Gas and Electric
3	SWIP-North	CAISO, WestConnect, NTTG	Great Basin Transmission, LLC
4	Transwest Express Transmission Project	CAISO, WestConnect, NTTG	TransWest Express, LLC
5	SWIP North	CAISO, NTTG, WestConnect	Great Basin Transmission
6	North Gila-Imperial Valley #2	CAISO, NTTG, WestConnect	ITC Grid Development

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 did not actively participate in the joint evaluation of any proposed ITP's during the 2016-2017 ITP evaluation cycle.

ITP's submitted in 2018

During the 2018 ITP submission window, six (6) proposed Interregional Transmission Projects were submitted to the Western Planning Regions as shown in Table 11.

Table 11: ITPs that were submitted to the 2018 submittal window

No	ITP Name	Submitted to	Project Proponent
1	TransWest DC	NTTG, WestConnect	TransWest Express LLC
2	TransWest AC/DC	NTTG, WestConnect	TransWest Express LLC
3	SDG&E HVDC Conversion	CAISO, WestConnect	San Diego Gas and Electric
4	TransCanyon Cross-Tie	NTTG, WestConnect	TRANSCANYON
5	SWIP North	CAISO, NTTG, WestConnect	Great Basin Transmission
6	North Gila-Imperial Valley #2	CAISO, NTTG, WestConnect	ITC Grid Development

Similar to 2016, 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 for evaluation. Currently, the Relevant Planning Regions are evaluating these ITPs. The scheduled completion time of this task is the end of 2019.

Alcoa Study Team

In 2015, the Aluminum Corporation of America (ALCOA) curtailed the production at its ALCOA Wenatchee Works plant until further notice. As a result, the loss of the ALCOA load has impacted electrical transmission and generation system operations in the surrounding Mid-Columbia area. Temporary procedures have been adopted to mitigate the impacts from the ALCOA plant shutdown.

In order to address potential system issues resulting from curtailment of the ALCOA load, a ColumbiaGrid Study Team was formed in 2016 with representatives from Chelan County PUD, Bonneville Power Administration, Grant County PUD and Douglas County PUD. This study team was tasked with evaluating long term plans from both a system operations and system planning point of view, in the scenario where the ALCOA plant does not resume operations. The technical studies that were conducted as part of this effort involved power flow thermal and voltage analysis. These studies evaluated potential needs for system reinforcements under normal and extreme stress levels on both 2-year and 5-year timeframes.

The study results identified a number of transmission facilities that could be overloaded under various conditions. However, no voltage or reactive margin issues were identified from the study. Seven (7) system mitigation options were proposed as long term mitigation plans. These long term alternatives can be grouped into five major categories as shown below:

- Implementation of additional emergency ratings
- Re-conductor of existing facilities
- Substation reconfiguration
- Construction of new facilities
- Use of special protection schemes.

Among these options, the study team evaluated the reliability impacts and economic effectiveness of each alternative. After considering all of the alternatives, the Study Team recommended a Remedial Action Scheme (RAS) option capable of reliably alleviating local thermal overloads. These findings and recommendations have been shared with the impacted parties in this area.

This Alcoa Study Team issued the “Sensitivity Study for Long Term Alcoa Shutdown Project” final report and concluded its activities in late 2017.

Quincy Study Team

In December 2017, ColumbiaGrid organized the Quincy Area Study Team to perform a load sensitivity study for the Quincy Area. The Study Team was tasked with addressing potential system performance issues and alternative mitigation solutions related to potential load growth that is projected to be higher than expected in Grant County Public Utility District's Quincy area. Currently, participants in this Study Team include representatives from the Bonneville Power Administration (BPA), Chelan County Public Utility District (CHPD), ColumbiaGrid (CG), Douglas County Public Utility District (DOPD), Grant County Public Utility District (GCPD), Puget Sound Energy (PSE), and other interested parties. The objectives of this Study Team can be divided into two major groups as shown below. In addition, the key activities and their timelines regarding this Study Team are summarized in Table 12:

- Examine the existing infrastructure in the Quincy area and identify transmission system constraints that may occur with higher load.
- Develop potential mitigation plans to serve the maximum projected load growth, maintain reliability, and improve operations and maintenance flexibility.

The following are key activities and the timelines regarding this Study Team:

- February 2018: The Study Team's kick off meeting was held to discuss the initial scope and the work plan
- May 2018: A draft study plan was developed and finalized.
- June – October 2018: The Study Team conducted the studies, reviewed the study results and drafted the study report. During the course of the studies, a number of WebEx and in person meetings were held to discuss the results, issues and the progress of the study.
- November 2018: The draft Study Team report was issued.

Table 12: Major activities of the Quincy Study Team

No	Activity	Timeline
1	Formation of the Study Team	December 2017
2	Kick off meeting	February 2018
3	Draft Study Plan issued	May 2018
4	Conducting technical studies	June - October 2018
5	Draft report issued	November 2018
6	Final report issued	March 2019

The technical studies that were conducted as part of this Study Team included power flow and voltage stability analysis. The study results identified seven potential thermal overload issues and four voltage issues that may occur as a result of potential changes in future system conditions. Each of these issues, as well as the effectiveness of the load serving plan proposed by GCPD to alleviate the problems, were evaluated by the Study Team. From the study results, the team concluded that the increased load forecast in the GCPD Quincy area could be reliably served in conjunction with the implementation of several mitigation plans. These include:

- A load serving plan that was developed by GCPD
- Increase the Columbia-Monument Hill 230 kV line rating by replacing existing line disconnect switches with 3000-amp rated switches
- Opening the line section between Mountain View Tap and Monument Hill,
- Implement additional mitigation plans that will be developed by DOPD to address its internal issues, and;
- Implement the Remedial Action Scheme (RAS) to address Rapids-Valhalla and Columbia-Valhalla line loading issues.

Currently, it is anticipated that this Study Team will issue the final Study Report for the Quincy Study Team in the first quarter of 2019.

Physical Security Third-Party Review

The North American Electric Reliability Corporation (NERC)'s CIP-014-2 Physical Security Standard's stated purpose is "to identify and protect Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack, could result in instability, uncontrolled separation, or cascading within an interconnection." The standard applies to any Transmission Owner that owns a transmission station or transmission substation that meets any of the criteria described in sections 4.1.1.1 through 4.1.1.4 of the standard[1].

Under Requirement R1 of the NERC Standard CIP-014, Transmission Owners must perform initial and subsequent risk assessments on applicable transmission stations and substations in order to identify stations that, if rendered inoperable or damaged could result in instability, uncontrolled separation, or cascading within an interconnection. Requirement R2 of the standard obligates Transmission Owners to have an unaffiliated third party verify the risk assessments which were performed under Requirement R1.

In 2015, ColumbiaGrid began offering third-party physical security risk assessment verification services to its members to assist them with their compliance obligations under CIP-014 Requirement R2. At that time, five ColumbiaGrid members utilized this service to verify their 2015 initial CIP-014 risk assessments. All of these risk assessment verification studies were completed during the fourth quarter of 2015.

Requirement R1.1 of the CIP-014 standard specifies that Transmission Owners shall perform subsequent risk assessments at least once every 30 calendar months for transmission stations that were identified in its previous risk assessment as requiring enhanced physical security evaluation. For stations not previously identified as requiring enhanced physical security evaluation, Transmission Owners must perform a subsequent risk assessment at least once every 60 calendar months.

In 2018, four ColumbiaGrid members identified transmission stations within their service territories for which a 30 month subsequent risk assessment was required as specified under requirement R1.1. These entities include:

- Avista Corporation (Avista)
- Grant County Public Utility District (Grant PUD)
- Puget Sound Energy (PSE), and
- Seattle City Light (SCL)

All of these utilities completed their 30 month risk assessments by the end of March, 2018 and subsequently requested that ColumbiaGrid perform a third party verification of their risk assessments.

ColumbiaGrid initiated this task in April 2018 and 9 substations were evaluated as part of this effort. The following tasks were performed by ColumbiaGrid to evaluate and verify the subsequent risk assessment studies conducted by each planning party.

- Assessment of applicability: ColumbiaGrid independently evaluated the substations in each planning party's service area in order to determine which stations require a risk assessment to be performed.
- Review of Requirement R1 subsequent risk assessment report: ColumbiaGrid reviewed each TO's risk assessment report to ensure that sufficient and accurate information was provided (per the Peak Reliability CIP-014 Guidelines) to perform a verification study.
- Perform independent evaluation: ColumbiaGrid conducted technical studies to evaluate the impacts within the Western Interconnection resulting from loss of transmission stations identified in each TO's subsequent risk assessment in order to verify their study results.
- ColumbiaGrid completed its verification studies and reports under the Second CIP-014 Functional Agreement with Avista, Grant, PSE and SCL by the end of June, 2018 or within 90 calendar days following completion of each TO's R1 subsequent risk assessments.

As required by the standard, it is anticipated that the next round of CIP-014 R1 assessments will need to be completed by September 2020 (30 months). The subsequent 3rd party verifications will need to be completed within 90 days or by December 31, 2020.

Relay Performance During Power Swing

In 2018, ColumbiaGrid initiated a new technical study that supports its members and planning participants in their compliance with North American Electric Reliability Corporation (NERC) Standard PRC-026-1. This study was conducted as part of ColumbiaGrid's 2018 annual study program and involved an assessment that identifies the transmission line Bulk Electric System elements in its area with associated protective relays that may operate following major disturbances.

The PRC-026 study was completed in November 2018 and the final report was issued in December 2018. The contents of this document provide an overview of this relatively new NERC standard, its requirements, the scope of the study in relationship with this standard, descriptions of the objectives, assumptions, and the methodology of the technical studies that were used to conduct the assessment. The report also includes a summary of the results and key findings from the study.

Study Assumptions and Methodology

In order to conduct this study, ColumbiaGrid worked with its planning participants to collect relay model data, develop the study methodology, perform the contingency analysis, and review the results. It was determined that at least four sets of data would be needed to perform this study. These include:

Power flow base cases: Based on conclusions from discussion with the planning parties, the PRC-026 study was conducted on three scenarios as shown below:

- 2019 Heavy Summer (19HS)
- 2019 Heavy Winter (19HW)
- 2019 Light Spring (19LS)

Dynamic data: ColumbiaGrid created the dynamic data file for each base case it developed in 2018 utilizing the WECC master dynamic data as the starting point.

Relay models: Attachment A of the PRC-026-1 standard lists the applicable load-responsive relays that must be evaluated which includes phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. In this study, ColumbiaGrid relied on relay models provided by its members and planning participants for the simulation. These models included transmission line distance, time inverse overcurrent, instantaneous relays and others. Table 13 summarizes the types and number of relays that were provided to ColumbiaGrid. However, at the time this study was performed, relay models for generator out-of-step tripping and loss-of-field relay functions were not available for the PowerWorld Simulator.

Table 13: Summary of the relay models data that were supplied to ColumbiaGrid

Relay Data		
Model	**Type**	**No. of Models**
DISTRELAY	Line Relay: Distance Relay	703
ZLIN1	Line Relay: Distance Relay	50
TIOCRS	Line Relay: Time Inverse Over-Current	187
DIRECLEN	Line Relay: Directional Element	130
RELODEN	Line Relay: Load Encroachment	34

For areas outside of the ColumbiaGrid footprint or facilities for which relay data is not available, additional relay models were incorporated in the base cases using the auto-insert function in the PowerWorld software. A total of 31,495 line DISTRELAY models were included in the base cases from the auto-insert function.

Contingency descriptions: The study group decided to evaluate the system response and relay operations for major contingencies that could incur significant power swings throughout the Western Interconnection. Initially, five contingencies were selected as part of the PRC-026 study. These contingencies represent outages of facilities on the bulk transmission system in the Pacific Northwest and other areas as shown below.

- The simultaneous loss of 2 units at the Palo Verde power plant (2-PVD)
- The simultaneous loss of all 3 units at the Palo Verde power plant (3-PVD)
- Loss of Grizzly – Malin and Grizzly Summer Lake 500 kV lines
- Loss of Round Mountain – Table Mountain and Malin – Round Mountain 500 kV lines
- Pacific DC Intertie Bipole outage

Two additional contingencies (listed below) were also run to test the relay tripping function of the PowerWorld software. These contingencies include:

- Loss of Malin – Round Mountain 500 kV lines #1 and #2
- Loss of Echo Lake – Raver 500 kV line

After populating the base cases with both generic relays as well as relay models supplied by transmission owners, ColumbiaGrid performed Transient Stability simulations on five (5) contingencies and recorded the relay trips that occurred from the events log. The study report was developed to document these activities and the study results.

Study Results

In the assessment study, all of the contingencies run with normal fault clearing times resulted in a stable system response (stable power swing). Study results showed that all of the transmission line distance relay trip events occurred on either the faulted circuit or in the general area of the fault. There were no other transmission line distance relays in the Northwest study area that tripped due to power swings resulting from the system disturbances studied. There were also no relay trip events recorded for the non-fault disturbances (2-PVD, 3-PVD, Pacific DC Intertie Bipole outage) simulated in this study.

The study results tables included in the report identify all transmission line BES Elements in the Northwest area where relay tripping occurred due to stable or unstable power swings during simulated disturbances.

Next Steps

Following the completion of ColumbiaGrid's 2018 annual study program, PowerWorld released a new generator protective relay model in the latest Simulator update which includes additional relay functionality. ColumbiaGrid will likely expand the scope of the PRC-026 related assessment in its 2019 study program to include reporting of generator as well as transmission line BES elements in the areas where relay tripping may occur due to power swings.

Model Validation

NERC Reliability Standard MOD-033-1 "Steady-State and Dynamic System Model Validation" mandates that Planning Coordinators (PCs) develop and implement a documented data validation process to validate their steady-state and dynamic system models every 24 months. The 1st round of MOD-033 studies was led by ColumbiaGrid staff and performed jointly with 11 utilities in Pacific Northwest under a ColumbiaGrid MOD-33 workgroup. The utilities included: Avista Corporation (Avista), Bonneville Power Administration (BPA), Chelan County PUD (CHPD), Cowlitz County PUD (Cowlitz), Douglas County PUD (DOPD), Grant County PUD (GCPD), PacificCorp (PAC), Puget Sound Energy (PSE), Seattle City Light (SCL), Snohomish County PUD (SNPD), and Tacoma Power (TCP).

The ColumbiaGrid MOD-033 workgroup initiated its activity in 2017 and concluded its activities in December 2018. The objectives of this joint effort were to develop guideline documentation and conduct validation studies that can be used to support workgroup participants in their compliance with the following requirements under the MOD-033 standard:

- R1.1 Comparison of the performance of the PC's portion of the existing system in a planning power flow model to actual system behavior;
- R1.2 Comparison of the performance of the PC's portion of the existing system in a planning dynamic model to actual system response;
- R1.3 Guidelines that the PC will use to determine unacceptable differences in the evaluated performances for the planning power flow and dynamic model;
- R1.4 Guidelines that the PC will use to resolve unacceptable differences in the evaluated performances for the planning power flow and dynamic model.

The workgroup adopted a documented model validation process jointly developed by ColumbiaGrid and the utilities. The contents of this document include several key aspects regarding MOD-033 standard such as:

- Summary of the requirements
- Procedures for Validation of Power Flow and Dynamic Data
- Guideline for Determining Unacceptable Difference
- Guideline for Resolving Unacceptable Difference

A copy of this document is available on ColumbiaGrid's public website at: https://columbiagrid.org/nerc-mod-33-model-validation-overview.cfm.

Following the development of the guideline documents, validation studies were conducted to compare the results from computer simulations (power flow and dynamic studies) with actual measurements. Generally, the scope of the comparison studies consists of seven major components as shown below:

- Event selection: Determination of the major events that will be used as the reference
- Data collection: Acquiring the West wide System Model (WSM) state estimator case that represents the event.
- Base Case development: Develop the power flow base case that has similar system conditions as the selected event
- Perform the comparison: Comparing the results from the simulations with the events
- Determine potential fixes: Identify potential issues that could deviate the simulation results from the actual events. Then request the data owners to review the results and issue potential fixes
- Implement the fixes: Incorporate the fixes and re-perform the comparison analysis
- Report development: Finalize the study and develop the report

The power flow model was successfully benchmarked according to the process. The modeled bus voltages and branch flows were compared to actual bus voltages and branch flows as represented by a WSM state estimator case at 08/08/2017 3:04AM. All compared values were within acceptable limits according to the guideline. As an example, Figure 6 shows the line flow comparison between a solved planning case and real-time measurements in Pacific Northwest for 3127 branches ranging from 0.6 kV to 500 kV.

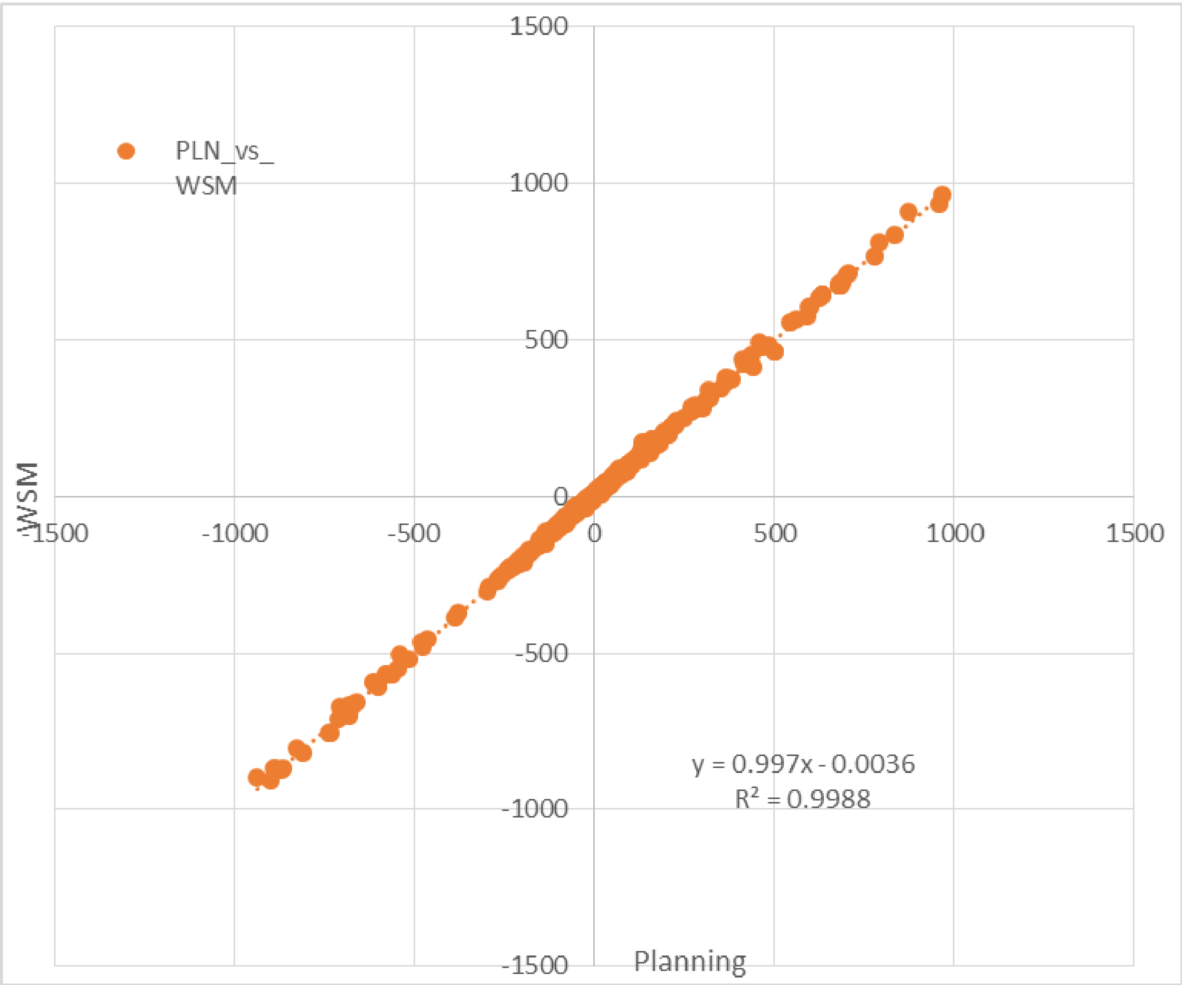


Figure 6: Power Flow Validation for Line Flows in Pacific Northwest

The dynamic model was benchmarked according to the documented process by comparing time domain dynamic simulation with continuously recorded system measurements during a significant disturbance event Pacific Northwest transmission system. This event happened in 08/08/2017 3:08AM. Most comparison of dynamic performance during and after the event matches well with no or small but acceptable difference. Several comparison results with large differences are considered as unacceptable. After investigating them, the workgroup identified dynamic model errors associated with them and most of them have been resolved. As an example, Figure 7 shows the dynamic validation of bus voltages between a time domain simulation of the event and real-time measurements from Digit Fault Recorders (DFR) in Puget Sound Energy substations.

The validation study will need to be performed again within the next 24 months.

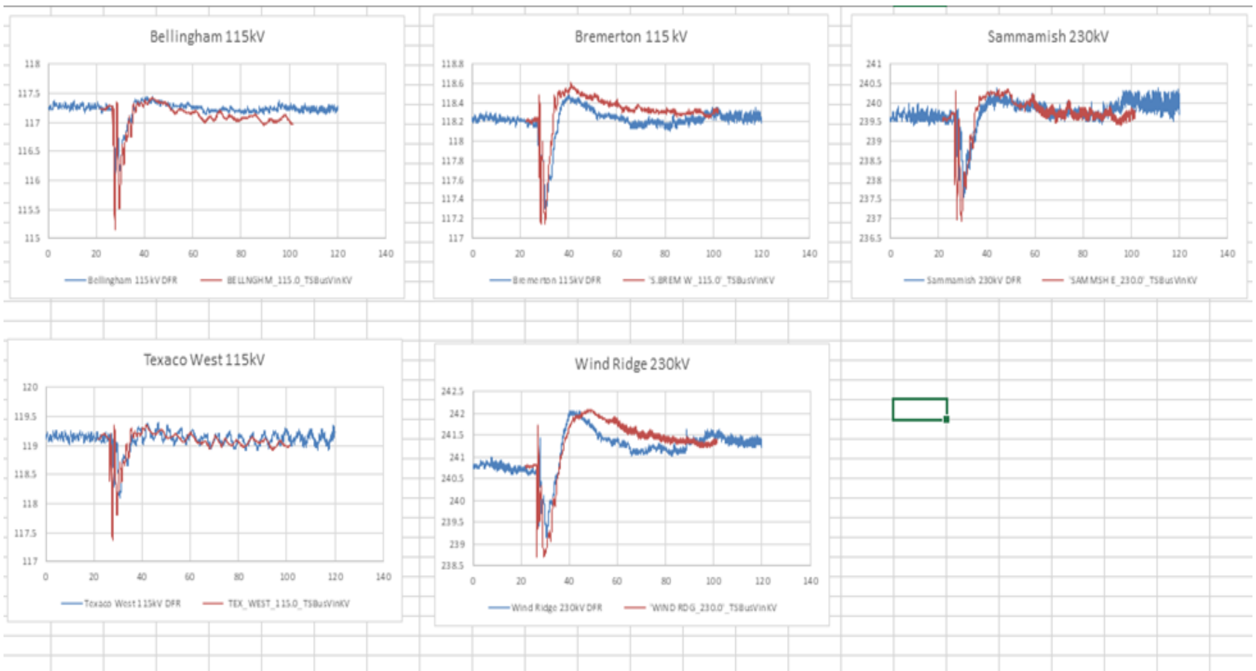


Figure 7: Dynamic Comparison for Bus Voltage between Simulation and DFR in PSE system

In addition to this study, ColumbiaGrid's comprehensive MOD-033 study approach has drawn wide attention from utilities in both the western interconnection and nationwide. The study work has been presented in technical forums including NERC SAMS (System Analysis and Modeling Subcommittee) and the WECC MVWG (Model Validation Work Group). In November 2018, ColumbiaGrid was invited to go through in detail its study principles, methodology and results with hands-on experience in a WECC MOD-033 workshop for utilities in the WECC region. It was also invited to a panel discussion dedicated to the latest technical achievements of system wide dynamic model validation in a 2019 IEEE PES General Meeting in Atlanta, GA along with ISOs and international utilities.

Transient Stability

ColumbiaGrid performed the 2018 transient stability study using a 2024 heavy summer case. The case represents a peak load condition with retirement of both Colstrip Units 1 and 2. The study was performed with TPL contingencies submitted by all ColumbiaGrid members except Bonneville Power Administration. No significant impacts were found to cause system instability. However, to better understand the system condition and potential impacts from retirement of the Colstrip units, it was suggested that ColumbiaGrid further evaluate the system stability using high voltage system contingencies from BPA, and include a light load condition where system inertia is low. Study of these scenarios will likely be performed in the 2019 system assessment.

Geomagnetic Disturbance

The Geomagnetic Disturbance Study was conducted to support its members' compliance obligations with requirements R4, R5 and R6 of the TPL-007-1 (Transmission System Planned Performance During Geomagnetic Disturbances) standard. The scope of this effort included:

- Collect and review the GMD data for the study
- Develop the GIC study base cases for the GMD data
- Determine the maximum effective GIC values at the worst case geoelectric field orientation for the benchmark GMD event. This screening assessment for transformer GIC flows was completed for all the applicable BES power transformers in the Northwest planning region.
- Identify any BES power transformers with a maximum effective GIC value of 75A per phase or greater. Subsequently, each of these transformers will require a thermal impact assessment to be performed by the responsible entity.

This study was initiated in 2017 and completed in 2018 and began with data collection and verification. The Western Electricity Coordinating Council (WECC) Master GIC data for the entire western interconnection was used as a starting point. This data was reviewed, corrected, and augmented by more detailed GIC system model data that was provided to ColumbiaGrid by its members. Utilizing this enhanced GIC system model, three base case scenarios were produced covering On-Peak and Off-Peak load conditions within the near-term transmission planning horizon. The scenarios were then evaluated for potential Geomagnetic-Induced Current (GIC) impacts.

- 2019 Heavy Summer: This base case represents an on-peak load condition within the Near-Term planning horizon when electricity demand in the Pacific Northwest region is very high.
- 2019 Heavy Winter: This base case also represents an on-peak condition within the Near-Term planning horizon during the winter season when the highest electricity demand in the Pacific Northwest region usually occurs.
- 2019 Light Spring: This base case represents an off-peak load condition within the Near-Term planning horizon.

As described in Attachment 1 of the TPL-007-1 standard, the study was conducted using a reference peak geo-electric field value of 8 V/km (defined at a geomagnetic latitude of 60°). Two scaling factors were applied to the reference geo-electric field value to account for regional differences based on the coordinates of the facilities. Among these scaling factors, the first set is the scaling factor to account for local geomagnetic latitude (in reference to the true geomagnetic north). A summary of these factors are shown in Table 14[1]:

[1]Table 1-1 of Attachment 1 of NERC TPL-007-1 standard

Table 14: Geomagnetic latitude scaling factor

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
55	0.6
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

The second scaling factors were the ground conductivities at the physical location of each substation which are provided by zone. A reference to these scaling factors is shown in Figure 8 and Table 15[2].

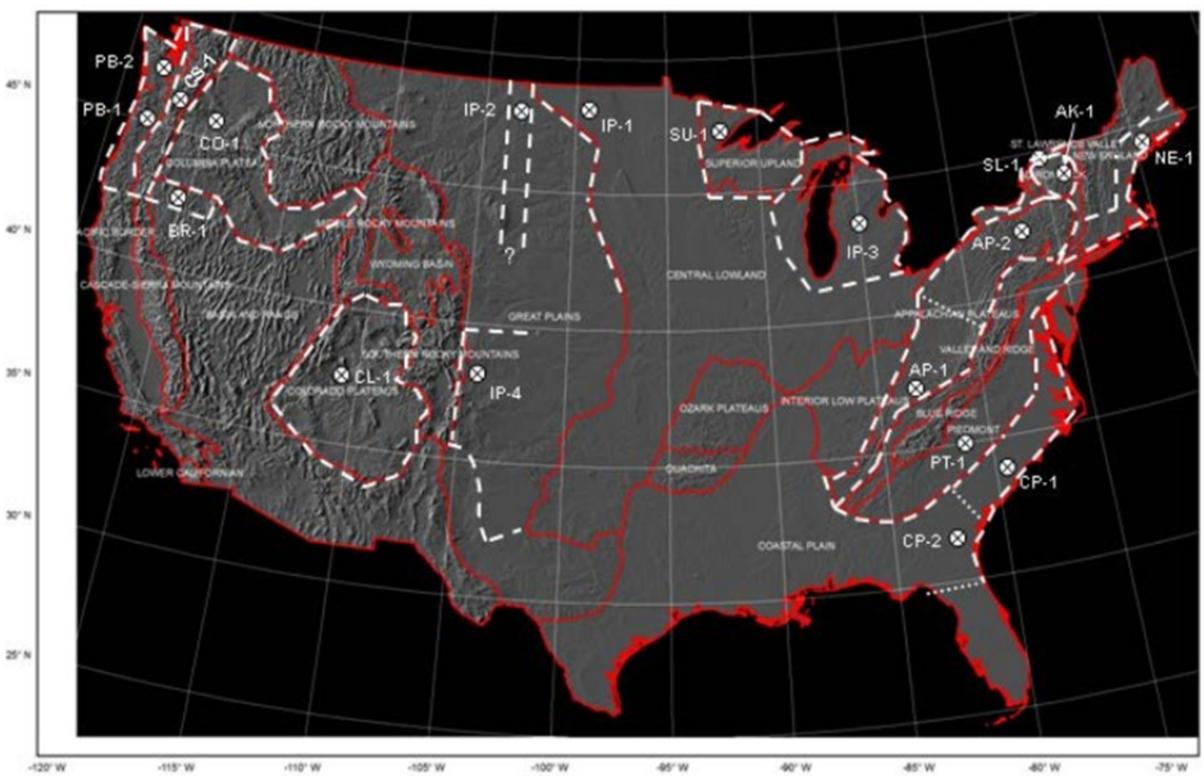


Figure 8: Ground Resistivity By Region

[2]Figure 1-1 and Table 1-2 of Attachment 1 of NERC TPL-007-1 standard

Table 15: Ground resistivity scaling factors

USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

After scaling the geo-electric field to account for local geomagnetic latitude and ground conductivity, the peak geo-electric field calculated for transmission substations in the Pacific Northwest region is generally less than 30% of the reference peak value.

The study results identified three transformers with maximum effective GIC flow values that could potentially exceed 75A in at least one of the three study scenarios. These transformers are:

- The Hot Springs 500/230 kV transformer showed GIC flows of 114.9A in the 2019 Heavy Winter, 84.5A in the 2019 Heavy Summer and 83.5A in the 2019 Light Spring case.

- The Bell 500/230 kV transformer showed GIC flows of 77.6A in the 2019 Heavy Winter, 77.4A in the 2019 Heavy Summer and 77.3A in 2019 Light Spring case.

- The Lane 500/230 kV transformer showed GIC flows of 75.9A for all three cases studied.

All of these values were peak GIC values calculated for the geo-electric field orientation that yielded the highest GIC flow for each transformer.

ColumbiaGrid will work with its members to determine any future tasks that expand the scope of the GMD study. This will likely include the performance of a GMD Vulnerability Assessment in 2019 that is required under TPL-007-1, requirement R4. ColumbiaGrid will also continue to track the development of NERC Standard TPL-007-2 and may extend the scope of the GMD study based on additional requirements in the new standard.

Economic Planning Study

The Economic Planning Study (EPS) has been part of ColumbiaGrid's annual study program since 2013. A goal of this study is to provide another set of information regarding potential future system conditions from the Production Cost Simulation. Basically, this type of study simulates potential hourly system behavior over the period of time being studied.

Since its inception, the scope of this study has been focused on evaluating system conditions within the ten year planning horizon. However, due to the implementation of recent mandates and public policies, significant changes are anticipated to occur beyond the ten year timeframe. Consequently, in order to address this and other issues, the following changes were made to the EPS that were conducted in this cycle:

- 15-year scenario: The 15-year scenario was included in the scope of the 2018 study. This resulted in two scenarios, 2028 and 2033, being studied in the 2018 study program.
- Model improvements: Additional model improvements were incorporated into the starting dataset. In general, these enhancements were developed internally by ColumbiaGrid staff to improve the accuracy of the simulation, which included:
  - ◊ Improved energy storage/pump storage operation
  - ◊ Expanded unit commit and dispatch with look-ahead logic
- Data exchange between PCM and Power Flow: In recent years, several improvements have been made to the Production Cost Model (PCM) software. One of these functions include the roundtrip function that was designed to facilitate the exchange of data between PCM and Power Flow. In 2018, ColumbiaGrid tested this function and compared it with other techniques previously utilized by ColumbiaGrid to export PCM data to power flow cases. For this study effort, ColumbiaGrid selected an hour corresponding to 1 PM on June 30, 2028 from the PCM simulation which has similar conditions as the Heavy Summer power flow case that was selected as the test hour.

Study Scope and Assumptions:

For the 2018 EPS study, ColumbiaGrid's production cost data set was developed using the ColumbiaGrid 2017 PCM as the starting point, which is based on the 2026 ADS seed case provided to WECC. Additional changes in study assumptions that reflect the latest developments following the issuance of the starting dataset were also applied. This dataset was first used in the 2017 EPS and has been revised again to be used in the 2018 EPS

As mentioned earlier, the 2018 EPS was conducted on two scenarios as below:

- Ten year study scenario (2028): In this case, ColumbiaGrid relied on the dataset that was used in the previous year study (2027 scenario) as the starting point. Then, appropriate transmission, supply and load based on WECC 2018 Load and Resource submittal, Utility Integrated Resource Plan (IRP), and other publicly available data were applied to create the 2028 dataset.

- Fifteen year scenario (2033): The dataset for this scenario was based on the 2028 dataset. Generally, additional changes regarding resources and load were made to create the 2033 dataset.

The datasets for both 2018 scenarios incorporated the following changes:

- Load Forecast: The following adjustments were made based on the WECC 2018 Load and Resource (L&R) submittal
  - ◊ The last three years of escalation was used to grow the load forecast from 2028 to 2033
  - ◊ The L&R forecast for California includes Additional Achievable Energy Efficiency (AAEE) which lowered the 2028 forecast by approximately 7,600 MW. Basically, AAEE has resulted in a flat load growth for California. This amount of AAEE is assumed to be the same in 2033 scenario.

- Utility Scale/Wholesale Renewables: Based on the latest available information, the total capacity of wind/solar resources for the entire WECC area that were modeled in the 2018 study were 28,655 / 50,402 MW, respectively. This is equivalent to approximately an 18% increase in the total capacity from the previous year study.

- Behind The Meter (BTM) PV: The total amount of BTM PV in the dataset for the entire WECC area was increased to 26,311 MW. This is equivalent to approximately a 33% increase from previous year study (19,690 MW).
  - ◊ For the areas where no data was available, the 2033 BTM PV was based on serving a 5% higher share of load. Example: If BTM PV serves 4% of load in 2028, in 2033 it would serve 4.2% (4% with a 5% increase).
  - ◊ Modeled BTM PV in California was 19,151 MW. This represents a 22% increase over the previous year's 15,643 MW. BTM-PV for California includes Additional Achievable Photovoltaic (AAPV)

A summary of the amount of BTM PV that was modeled in each dataset is summarized in Table 16 and Figure 9.

Table 16: Summary of BTM PV capacity that was modeled in each scenario

Area	BTM PV Capacity (MW)		
	2027	2028	2033
CA	15,643	19,151	24,994
Other areas	4,047	7,160	8,347
WECC Total	19,690	26,311	33,341

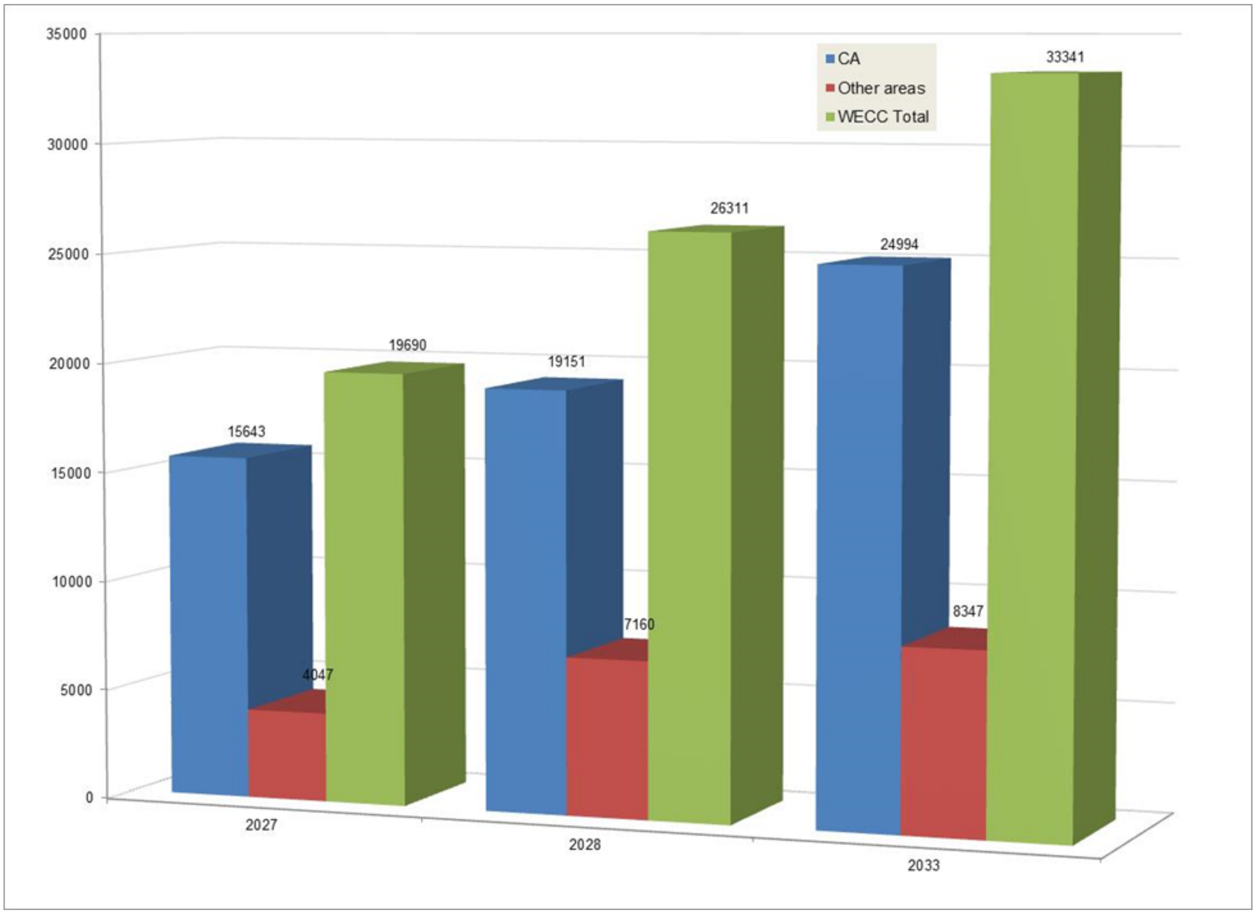


Figure 9: BTM PV capacity that was modeled in each scenario

- Resource retirement: Planned retirements were based on publicly available data, IRP, or WECC 2018 L&R. New to the retirement list are PacifiCorp (PAC) coal retirements based on their 2017 IRP, and the retirement of Navajo (2,250 MW).
- Supply additions: Based on utility IRP and the WECC 2018 L&R, additional resources were added to minimize the impact on the local transmission system. The objective was not to perform an interconnection study, but to evaluate the impact of new supply on the bulk transfers between major markets

Study Results:

The results from the 2018 study and the comparison with a similar study that was conducted in 2017 are summarized below. These results focused on several issues that are related to future system behaviors such as:

- Average power flow: The average MW flow on transmission paths for the entire simulation which is equal to the summation of hourly power flow on the monitored paths divided by 8760. This index provides an indication of transmission path utilization.
- Average intra-day swing: The average value of the difference between the highest and lowest flow (swing) on each monitored path for each day which is equal to the summation of each day's swing divided by 365. This value attempts to illustrate the volatility of power flow on each path.
- Minimum flow: This value represents the lowest daily flow on each path for the entire simulation. This is an indication of potential impacts due to higher renewable penetration, which would include reverse flow during certain days.
- Resource cycling: The higher level of renewable penetration in the 2018 scenarios resulted in higher system volatility and ramp rates that also impacts the operation (on/off or cycle) of units that were used to balance the system. In this report, the incurred costs due to the cycling of non-renewable units such as combined cycle were collected to represent an impact from supply changes.

Please note that while these indices attempt to provide some perspectives regarding the behavior of future system conditions, they may not offer a complete picture of future system dynamics. Additional information may be needed to offer a more comprehensive view of the system.

Overall, the study results from the 2018 EPS showed that:

- The average power flow (particularly export from the Pacific Northwest), in the ten and fifteen year scenarios is anticipated to be lower than current levels. This is partly due to higher load growth in the area and retirements of local resources.
- The average intra-day swings in the ten and fifteen year scenarios is projected to be higher than current levels. This is due to the impacts from higher levels of renewable penetration as well as operational characteristics associated with Solar PV. It is also interesting to note that, while California has the most aggressive RPS goal and renewable penetration, the impacts from this change can also be seen on transmission paths that have no direct connection with the California system.
- The minimum flow on major paths appears to be lower than current levels and is projected to shift towards mid-day. This behavior was also driven by higher penetration of renewable resources that could significantly change or potentially reverse the direction of power flow on major transmission paths during daily operation. The 2018 EPS results indicate that daily minimum or reverse flows on Northwest paths are likely to occur during mid-day instead of during historic off-peak periods.
- Study results also suggest the possibility that the Northwest region will be a net importer from California.

Northwest to California: These include WECC Path 65 (Pacific DC Intertie – PDCI) and WECC Path 66 (California-Oregon Intertie) which are the two major transmission paths that connect these two regions.

The average power flow across the total Northwest-California paths (Path 65 + Path 66) from the 2028 scenario is 2,850 MW which is 319 MW lower (approximately 10%) than the results from the 2027 scenario that was conducted in 2017.

The average intra-day swing in the 2028 scenario is 5,500 MW. This is 1,905 MW (53%) higher than the scenario that was conducted in 2017. This higher intra-day volatility in the system is due to higher levels of solar penetration throughout WECC, i.e. the system is responding to abundant mid-day surplus power, The hourly plot of the total flow across these two paths from the 2017 and 2018 studies are shown in Figure 10

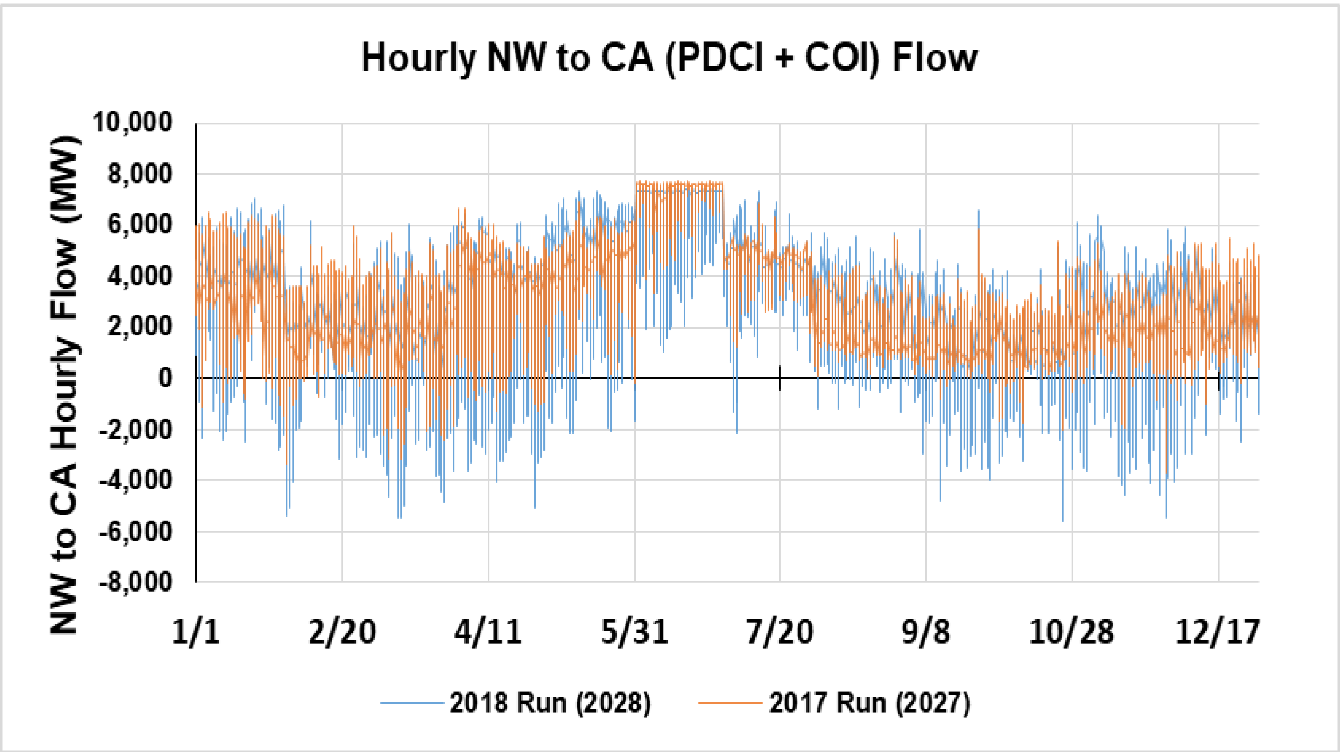


Figure 10: Comparison: Hourly Flow on Net NW to CA (PDCI+COI) Day from Base 2017 (2027) and 2018 (2028)

The average power flow across the total Northwest-California paths in the 2033 scenario is 3,103 MW. This is slightly higher (253 MW) than the 2028 scenario, but on par with the 2027 scenario. However, the average 2033 intra-day swing drops slightly from the 2028 scenario. Overall, the average swing decreases from 5,500 MW to 5,170 MW (330 MW or approximately 6%). The hourly plot of the total flow from the 2028 and 2033 scenarios are shown in Figure 11.

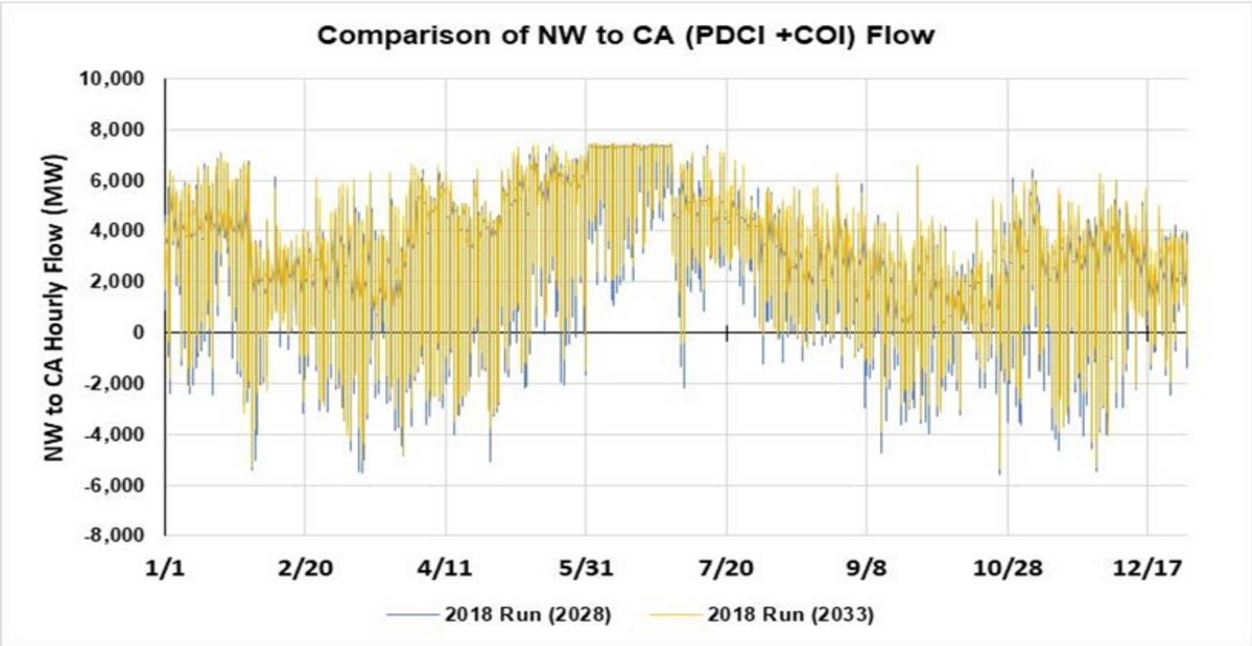


Figure 11: Comparison: Hourly Flow on Net NW to CA (PDCI+COI) Day from Base 2018 (2028 & 2033)

Flow patterns are changing with the abundant mid-day solar. The historic trend of minimum flow on a path occurring during the off-peak time period is changing to mid-day. This mid-day flow may even reverse direction. In the 2028 scenario, reverse flow occurs on 228 days of the year. This is up from the 81 days in the 2027 scenario. The following two charts show the average hour ending flow for weekdays. This provides a base/average hourly profile for the month. During March (Figure 12) the Northwest average weekday flow is reversed, i.e. the Northwest is importing for five hours a day during the 2028 scenario. During the 2033 scenario this import drops to 4 hours. Switching to August (Figure 13) there was no clear mid-day reduction in flow during the 2027 scenario. The 2028 and 2033 scenarios both show a clear mid-day reduction in flow but the average flow does not reverse as seen in March. Examples of this trend are shown in Figures 12 and 13.

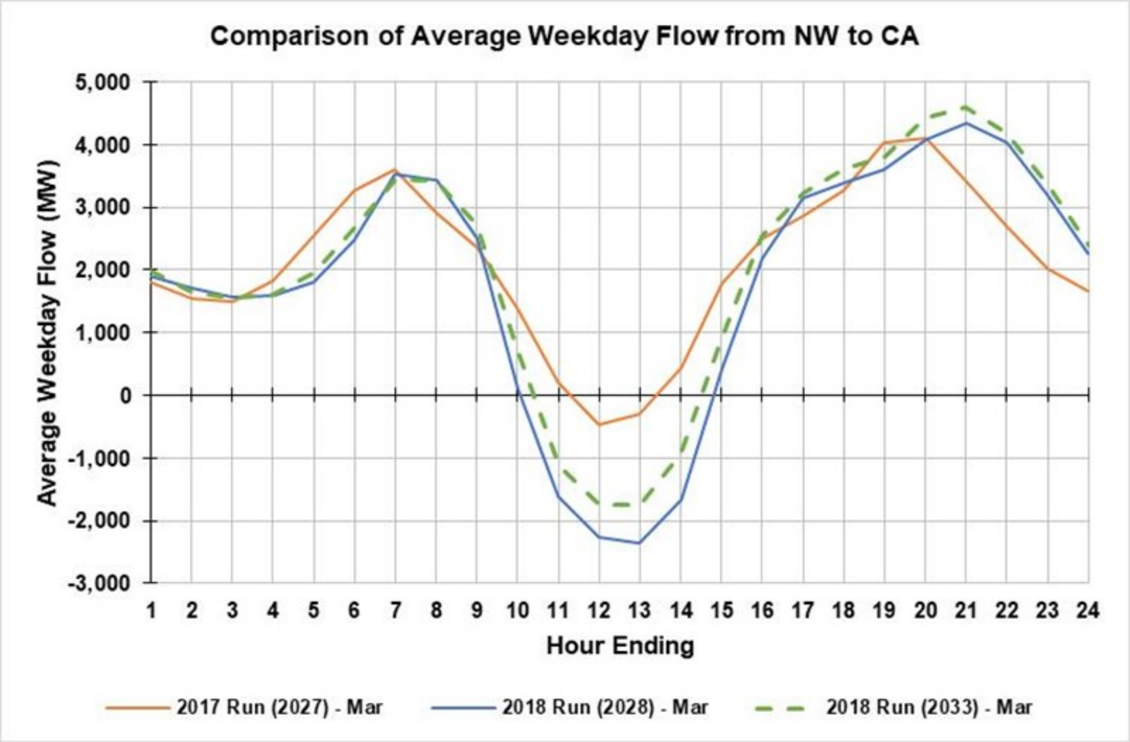


Figure 12: Comparison of Average Weekday Flow on Net NW to CA (PDCI+COI) from Base 2017 (2027) and 2018 (2028 & 2033) for March

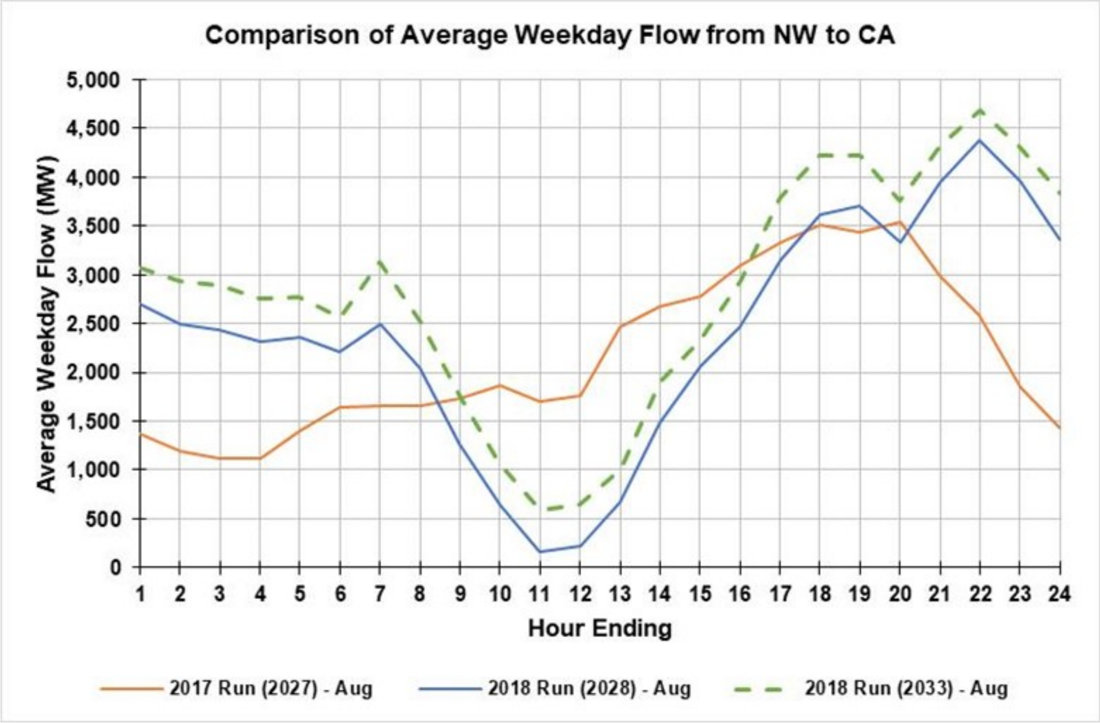


Figure 13: Comparison of Average Weekday Flow on Net NW to CA (PDCI+COI) from Base 2017 (2027) and 2018 (2028 & 2033) for August

North of John Day Flow (Path 73): This is a major transmission path that has strong connection with other key transmission facilities and resources in the Pacific Northwest.

The results from the 2018 EPS showed some reduction in average flow compared to previous studies. Basically, the 2028 scenario has an average power flow of 1,700 MW which is approximately 505 MW (-23%) less than the 2027 scenario. The hourly flow on this path from the simulation is shown in Figure 14.

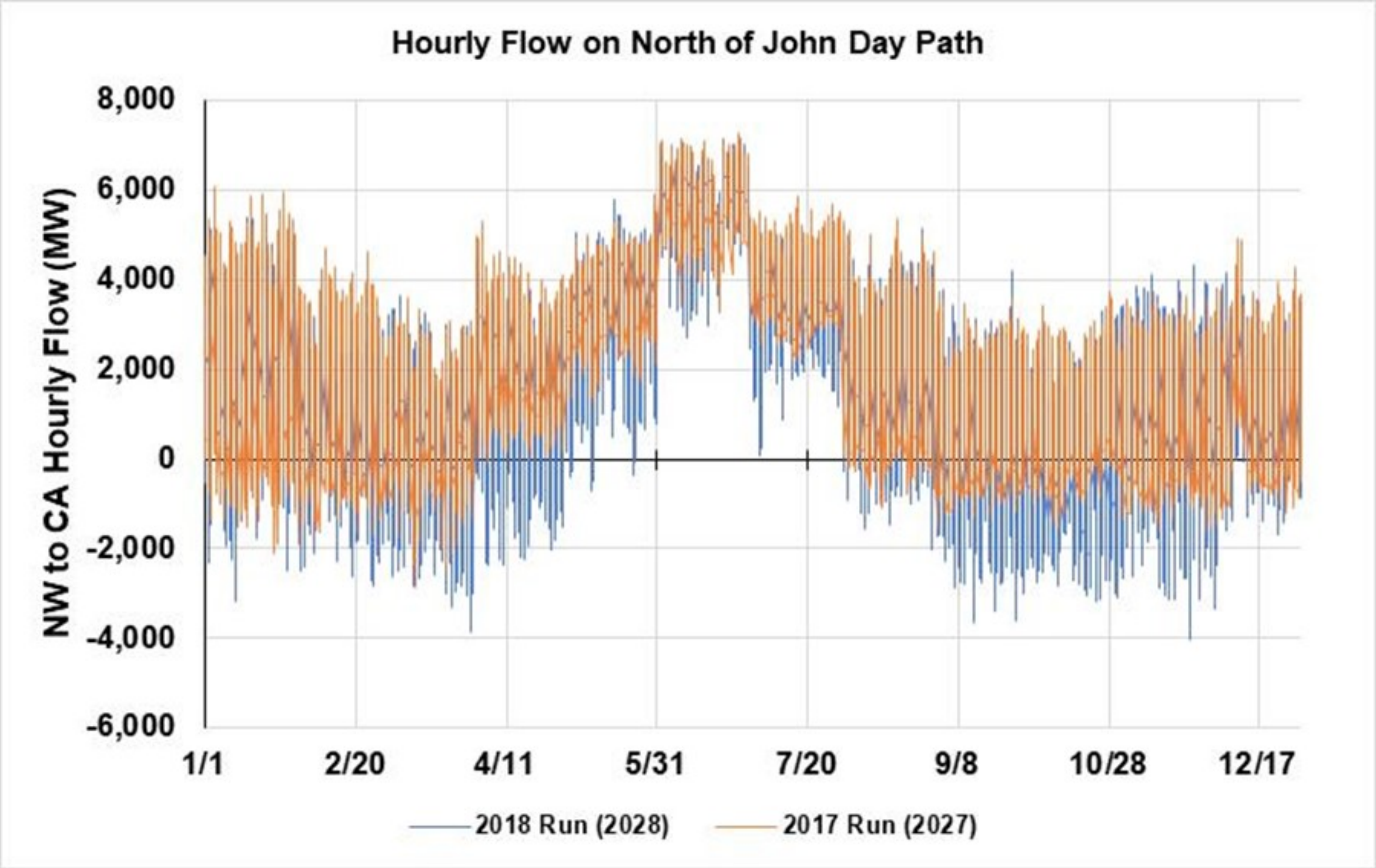


Figure 14: Comparison of Hourly Flow on North of John Day from Base 2017 (2027) and 2018 (2028)

The 2033 scenario has an average flow of 1,386 MW which is a 819 MW (-37%) drop from the 2027 scenario. The hourly plots of this scenario are shown in Figure 15.

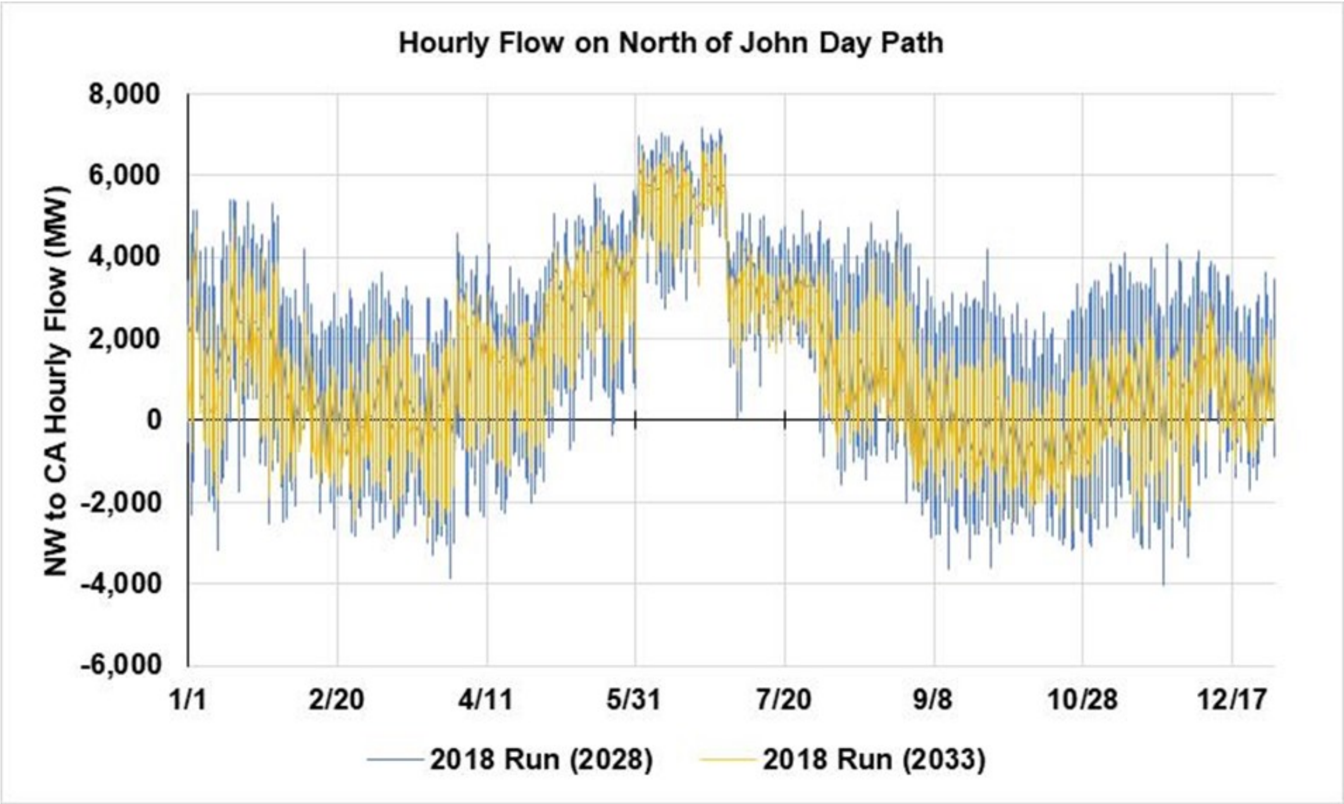


Figure 15: Comparison of Hourly Flow on North of John Day from Base 2018 (2028 & 2033)

The average 2028 intra-day swing increases 546 MW (14%) from 3,799 MW in the 2017 study. This shows a similar behavior as seen in the Northwest to California flow even though it has no direct connection with California. In addition, the average intra-day swing from the 2033 scenario decreases 1,774 MW (approximately 41%) from 4,344 MW in the 2028 scenario.

The average weekday flow shows minimum flow during mid-day. In March, the flow is reversed and in August it is right at zero in both the 2028 and 2033 scenarios. More information regarding this pattern is shown in Figures 16 and 17.

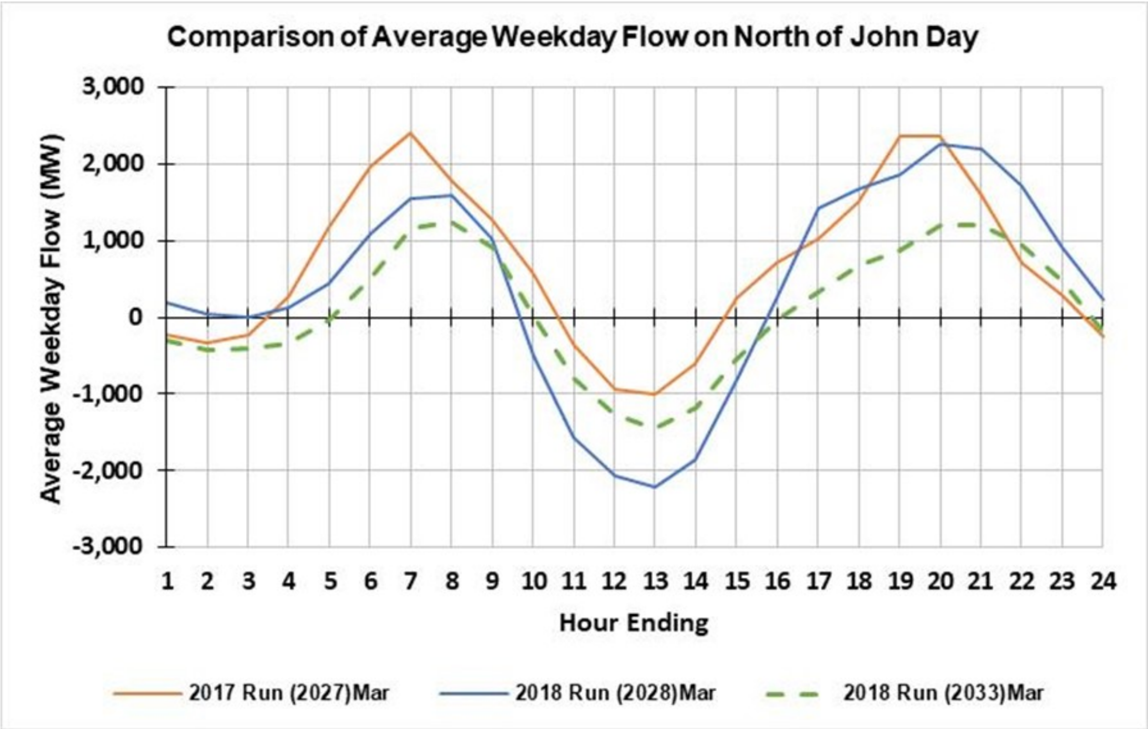


Figure 16: Comparison of Average Weekday Flow on North of John Day from Base 2017 (2027) and 2018 (2028 & 2033) Studies (March)

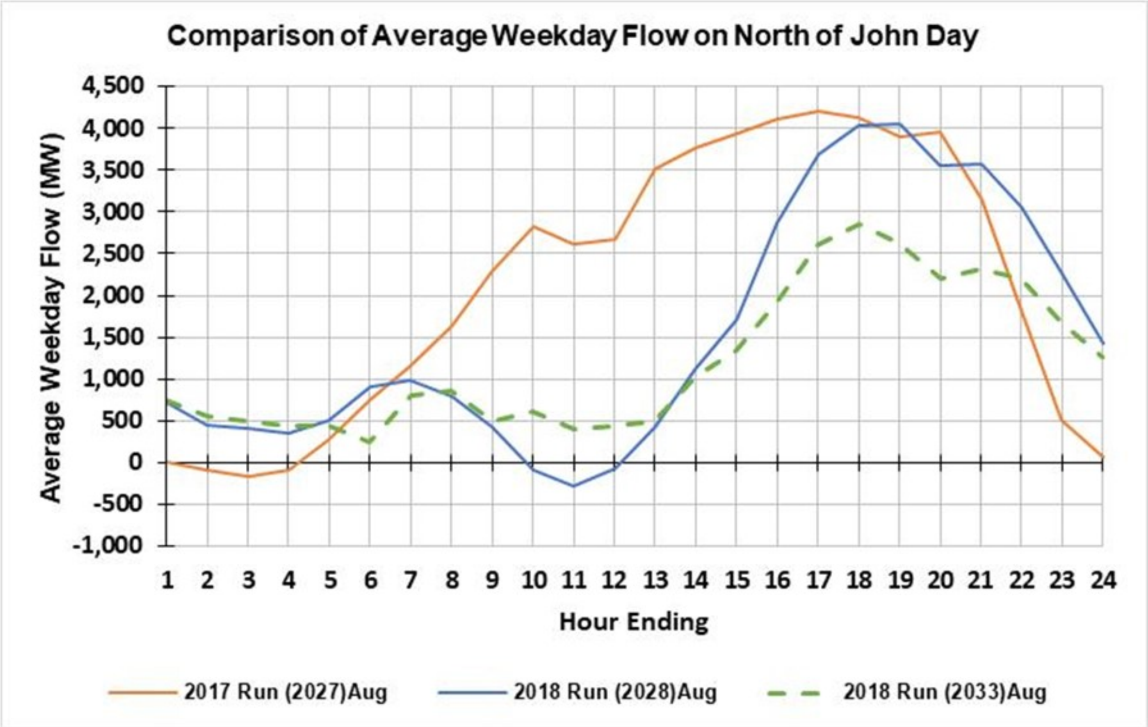


Figure 17: Comparison of Average Weekday Flow on North of John Day from Base 2017 (2027) and 2018 (2028 & 2033) Studies (August)

A shift in mid-day flows occurs on most major paths within WECC. Its impact on each path is a function of how the downstream generation responds to the abundant mid-day surplus of solar generation from California and the Southwest. The Hemingway – Summer Lake (WECC Path 75) path is a major transmission path connecting Northwest (north of COB) to the inland power market (IPC and PACE).

Figure 18 shows March with the same mid-day minimum flow pattern. In August, Figure 19, the pattern does not show a clear mid-day shift in flow. The mid-day shift is not propagating to this path in August. It's not the peak season in the Northwest while it is in the inland market. Therefore, only the Northwest responds to mid-day volatility in August while in March both the Northwest and Inland markets are responding.

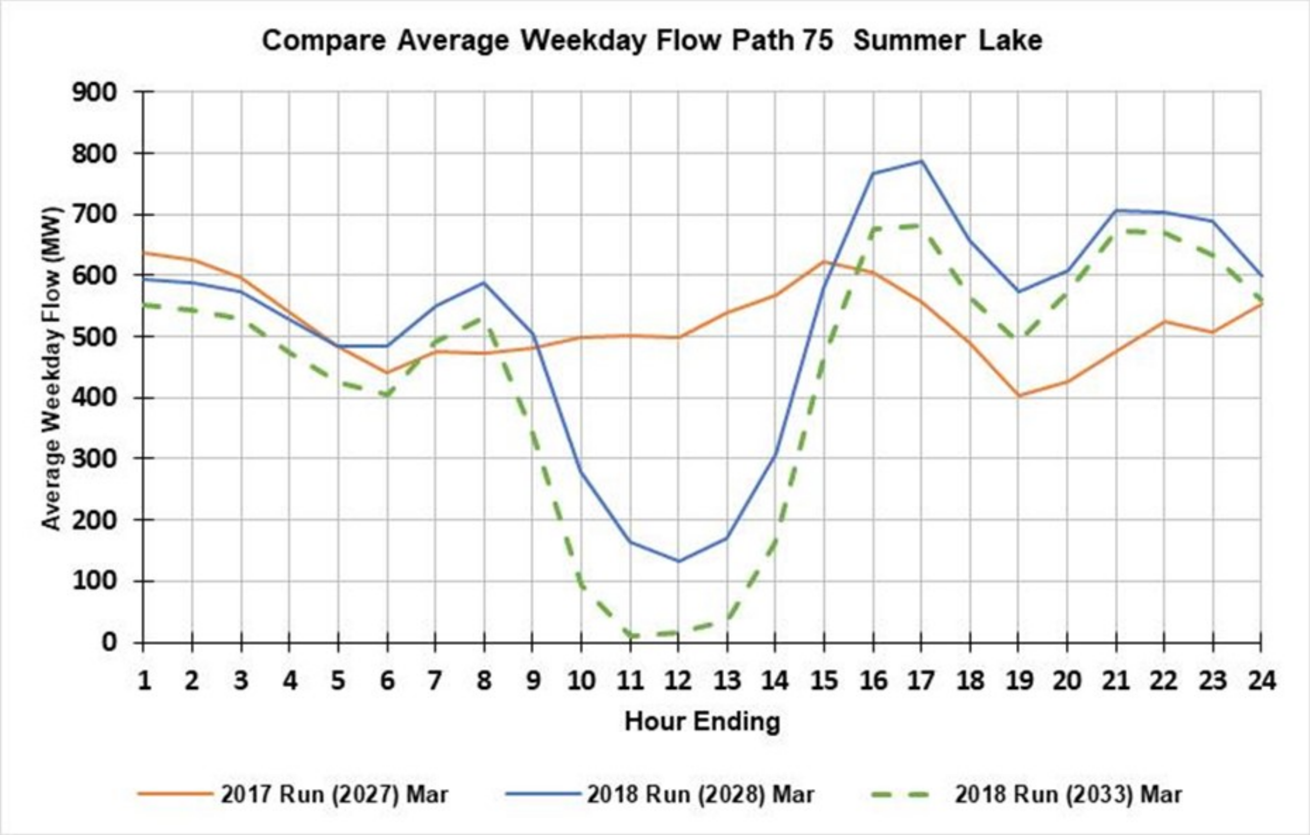


Figure 18: Comparison of Average Weekday Flow on Path 75 from Base 2017 (2027) and 2018 (2028 & 2033) Studies (March)

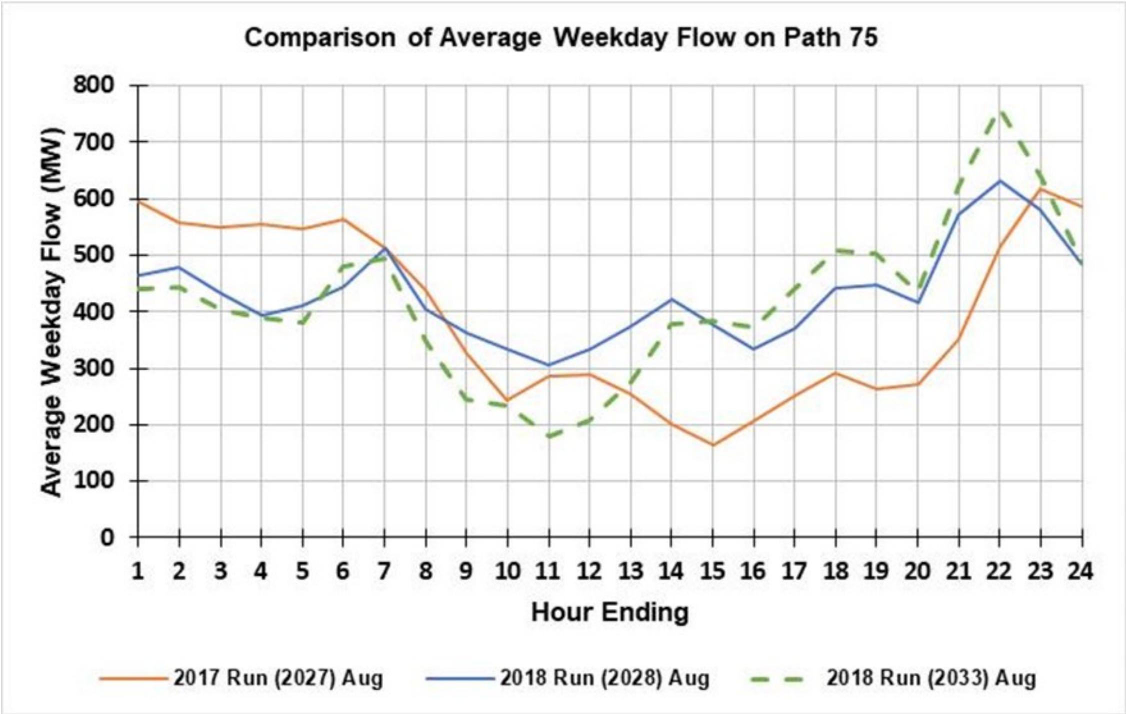


Figure 19: Comparison of Average Weekday Flow on Path 75 from Base 2017 (2027) and 2018 (2028 & 2033) Studies (August)

The increase in mid-day volatility on each path will be a function of season, relationship to surplus solar and downstream generation. This is driven by several factors:

- Retirement of traditional base load supply
- The addition of renewable resources, primarily solar
- The addition of new dispatchable supply and its location

Another modeling observation to note is the increased cycling of combined cycle units outside of California. To minimize this behavior, additional modeling constraints were applied outside of California. This is driven by the increased solar supply placing additional stress on the WECC system. Assuming a start cost of $15,000/start for an F-Frame combined cycle unit, the net start cost outside of California goes to $120 million dollars to support the afternoon ramp, compared to 2017 Base PCM results of $60 million dollars.

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