Docket No. 21-035-54

UAE Exhibit 1.2

Northern Tier Transmission Group

2018-2019 Draft Final Regional Transmission Plan

Revised September 18, 2019

NTTG 2018-2019 DRAFT FINAL REGIONAL TRANSMISSION PLAN

Revised 9-18-2019

Preface

The NTTG 2018-2019 Regional Transmission Plan (RTP) is meant to inform local transmission planning processes and is not a construction plan. NTTG relies on the load and resource data submittals of its members and does not consider the re-dispatch or re-optimization of resource assumptions. The RTP studies are completed pursuant to the NTTG Transmission Providers' Attachment K.

NTTG's transmission plan assumes that its members' submissions are reasonable and cost effective. The transmission plan is not an attempt to design an optimal portfolio of resources to meet the expected demand of the region's consumers. Instead, it is an attempt to design a reliable and cost-effective portfolio of transmission around the inputs of NTTG Members. The RTP is the result of the assumptions outlined in the report and solely represents a lower-cost transmission plan than one represented by a rollup of the combined Transmission Provider's plans.

To the degree that those NTTG Transmission Providers' inputs are not realistic or cost-effective, the resulting NTTG Transmission Plan will likely be affected. However, NTTG regards correcting such potential errors as work to be undertaken in the context of integrated resource plans conducted by individual load-serving entities in their respective states.

I. Executive Summary

The objective of the Northern Tier Transmission Group ("NTTG") Regional Transmission Plan ("RTP") is to evaluate, from a regional perspective, whether NTTG's transmission needs may be satisfied on a regional or interregional basis more efficiently or cost effectively than through local planning processes. This report is the result of the assumptions outlined in the report. The consumers of the report must recognize this and factor it into their deliberations. NTTG's 2018-2019 Regional Transmission Plan will be finalized and posted by the end of Quarter eight, December 2019.

During the first year of the NTTG 2018-2019 biennial planning cycle, the Technical Work Group ("TWG") of the NTTG Planning Committee evaluated the prior Regional Transmission Plan ("pRTP") developed in the 2016-2017 planning cycle, the Initial Regional Transmission Plan ("IRTP")[1] and 33 Change Case[2] plans that included Non-Committed regional projects and Interregional Transmission Projects to determine a more efficient or cost effective plan. The complete study methodology can be found in Section III. Through a reliability study process the TWG narrowed the number of potential Draft Regional Transmission Plan ("dRTP") cases to two – the IRTP and the pRTP. Following the economic analysis of the two alternatives, the pRTP configuration was selected as the 2018-19 cycle dRTP.

NTTG received and incorporated stakeholder comments on this dRTP during Quarter five. At the end of Quarter five, data updates and one Economic Study Request were submitted. NTTG determined that there were no material changes to the Quarter one submittals in the Quarter five data submissions that would cause a change in the dRTP selection.

NTTG performed one robustness study on the dRTP in Quarter five, increasing 2028 loads to test a higher growth 15 to 20 year perspective. To supply this load growth, TWG added a wind and solar resource mix to each balancing area. The results of that analysis can be found in Section XI of this report.

NTTG conducted an economic analysis of the IRTP and the pRTP after completing the reliability analysis. The economic analysis compared the annualized incremental costs of the two Change Cases. The annual incremental cost was computed as the sum of three metrics - the capital related costs, monetized energy loss benefit and monetized reserve benefit. Figure 1 below displays the results of the annualized incremental cost analysis.

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[1] The IRTP includes projects in the prior Regional Transmission Plan, projects in the Funders Local Transmission Plans, and accounts for future generation additions and deletions (e.g., announced coal retirements).
[2] A Change Case is where one or more of the Alternative Projects is added to or replaces one or more Non-Committed Projects in the IRTP. The deletion or deferral of a Non-Committed Project in the IRTP without including an Alternative Project can also be a Change Case.

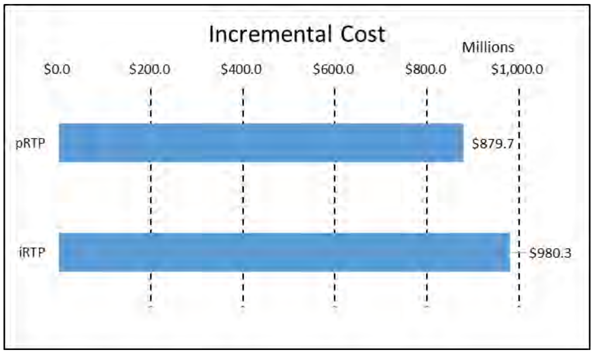


Figure 1 – Summary of Annualized Incremental Costs for 2028 NTTG Study Cases

Based on the reliability and economic considerations for the transfers studied, the more efficient or cost-effective draft plan is the pRTP. Detailed pictorially, the dRTP[3] is comprised of the following regionally significant Non-Committed Projects:

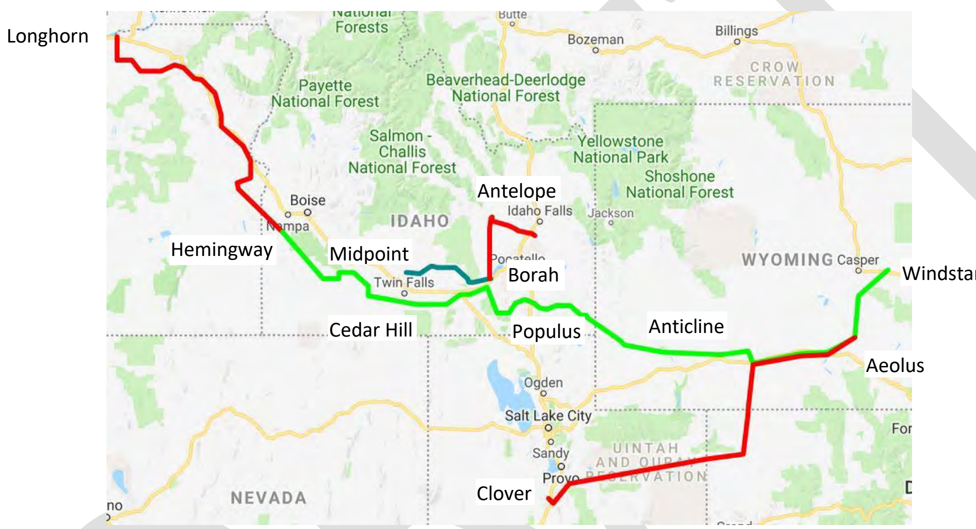


Figure 2 - dRTP Projects

II. Introduction

The NTTG 2018-2019 Draft Regional Transmission Plan was developed in accordance with the NTTG's Transmission Providers' Attachment K that included FERC Order 1000 regional and interregional transmission planning requirements[4]. The dRTP is a result of reliability and economic studies and activities outlined in the NTTG Biennial Study Plan for the 2018-2019

[3] The dRTP is comprised of the same projects included in the pRTP.
[4] Link to Full Funder Attachment Ks

Regional Planning Cycle[5] and carried out by the NTTG Technical Work Group[6]. In Quarter one and again in Quarter five, NTTG receives data from its Transmission Providers ("TPs") and stakeholders concerning forecasted firm obligations and commitments that the NTTG footprint transmission system is required to support. These data include load forecast, resource, transmission service, and Public Policy Requirement submissions described in further detail below.

A. Load Forecast

The forecasted loads for Balancing Authority Areas internal to the NTTG footprint were provided in response to the Quarter one data request. These loads represent an average expected peak[7], and are generally those in the participating load serving entities' official load forecasts (such as those in integrated resource plans) to serve network load and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. In Quarter five, NTTG requested that transmission Providers and Stakeholders provide updates to the data provided in Quarter one if there have been any material changes. Table 1 summarizes the load forecast used in the 2018-2019 planning cycle.

SUBMITTED BY:	2017 Actual Peak Demand (MW)	2026 Summer Load Data Submitted in 2016-17 (MW)	2028 Summer Load Data Submitted in Q1 2018 (MW)	2028 Summer Load Data Submitted in Q5 2019 (MW)	Difference (MW) 2026-2028
Idaho Power	3,806	4,346	4,412	4299	-47
NorthWestern	1,803	1,992	2,027	2030	38
PacifiCorp	12,664	13,044	13,386	13,386	342
Portland General	4,023	3,885	3,928	4060	175
TOTAL*	22,296	23,267	23,753	23,775	508

* Loads for Deseret G&T and UAMPS are included in PacifiCorp East

Table 1: January 2018 Data Submittal – Load Comparison[8]

[5] Link to the 2018-2019 NTTG Study Plan

[6] This work group was established by the NTTG Planning Committee chair to create the study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan. The TWG is comprised of the NTTG Planning Committee members or their representatives who have access to and expertise in power system power flow analysis or production cost modeling, are committed to participating in the entirety of the planning process (not just a single study or phase), and will ensure completion of those assignments in a cooperative and timely manner.

[7] A peak condition that has an equal probability to occur or not in a given year, sometimes referred as a 50 percent exceedance level or a 1 in 2 peak. A 1 in 5 peak would have a 20 percent chance of exceedance.

[8] Revised in Quarter five.

B. Resource submissions

The following Figure 3 and Table 2 summarize the resources provided in response to the Quarter one and five data requests. These resources are incremental to existing resources within the NTTG footprint.

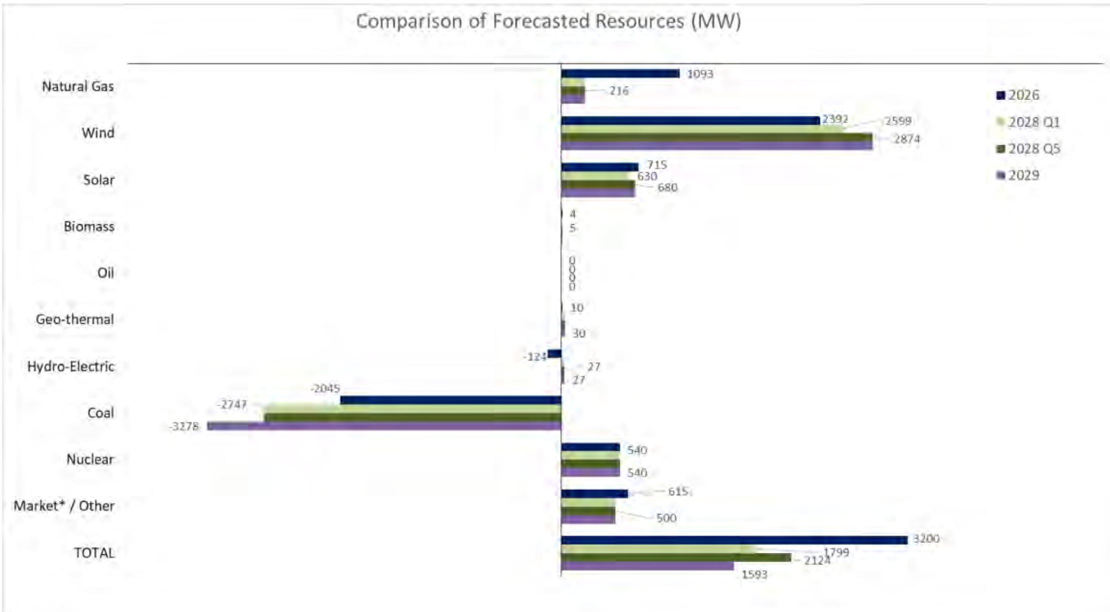


Figure 3: Comparison of Forecasted Resources

State	Net Resource Change (MW)
Arizona[9]	-414
California	0
Colorado[9]	-82
Idaho	588
Montana	573
Oregon	-41
Utah	452
Washington	108
Wyoming	727[10]

[9] Reflects PacifiCorp's retirement of Cholla 4 and Craig 1, which are coal resources outside the NTTG footprint.

[10] Prior to the Q1 data deadline PacifiCorp submitted 1100 MW for its Energy Vision 2020 wind resource acquisition. During the review of the submittals and reviewing PacifiCorp's 2017 IRP Update it was apparent that the Energy Vision 2020 acquisition had materially changed to 1311 MW. To align the NTTG's studies with PacifiCorp's current plan, a revised data submittal was made by PacifiCorp and incorporated into this document. The net resource change for Wyoming includes the retirement of Dave Johnson units 1 through 4.

Table 2: Location of 2028 Forecasted Resources

As shown in Figure 3, the total resource forecast of 1799 MW submitted this cycle is reduced (-1401 MW or -43.8%) from the 3200 MW forecast in 2026.

Coal retirements submitted in Q1 of 2018 are listed in Table 3 below.

Coal Unit	Retirement Date[11]	Study Treatment
Naughton 3	12/2018	Retired
Valmy 1	12/2019	Retired
Boardman	12/2020	Retired
Cholla 4[12]	12/2020	Retired
Colstrip 1 & 2	7/2022	Retired
Valmy 2	12/2025	Retired
Craig 1[12]	12/2025	Retired
Dave Johnson 1, 2, 3, 4	12/2027	Retired
Bridger 1	12/2028	On-line, Retired in Sensitivity case

Table 3 – Planned Coal Retirements to be studied in the 2018-2019 planning cycle[13]

C. Transmission Facilities and Service submissions

Listed below in Table 4 are the regional transmission projects that were submitted in Quarter one. The project types are the following: prior Regional Transmission Plan (pRTP), Full Funder Local Transmission Plan (LTP), Sponsored Project, unsponsored Project, or Merchant Transmission Developer. The Initial Regional Transmission Plan was derived from projects included in the prior Regional Transmission Plan and projects included in the Full Funders' local transmission plans.

[11] Units are assumed to retire at the end of the stated month.

[12] Reflects PacifiCorp's retirement of coal retirements outside the NTTG footprint

[13] PacifiCorp currently is planning to retire Naughton 1 and 2 after 12/31/2029, i.e. at the beginning of 2030-31 Planning Cycle, so those retirements will be considered by NTTG during the next Planning Cycle.

MARCH 2018 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2028

Submitter	From	To	Voltage	Circuit	Type	Regionally Significant	Committed	Projects (In-service Year)
Idaho Power	Hemingway	Longhorn	500 kV	1	LTP & pRTP	Yes	No	B2H Project (2026)
	Hemingway	Bowmont	230 kV	2	LTP	Yes	No	New Line - associated with Boardman to Hemingway (2026)
	Bowmont	Hubbard	230 kV	1	LTP	Yes	No	New Line - associated with Boardman to Hemingway (2026)
	Hubbard	Cloverdale	230 kV	1	LTP	No	No	New Line (2021)
	Midpoint	Hemingway	500 kV	2	LTP	Yes	No	Gateway West Segment #8 (joint with PacifiCorp East) (2024)
	Cedar Hill	Hemingway	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #9 (joint with PacifiCorp East) (2024)
	Cedar Hill	Midpoint	500 kV	1	LTP	Yes	No	Gateway West Segment #10 (2024)
	Midpoint	Borah	500 kV	1	LTP & pRTP	Yes	No	(convert existing from 345 kV operation) (2024)
	Ketchum	Wood River	138 kV	2	LTP	No	No	New Line (2020)
	Willis	Star	138 kV	1	LTP	No	No	New Line (2019)
Enbridge	SE Alberta		DC	1	LTP	Yes	No	MATL 600 MW Back to Back DC Converter (2024)
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP & pRTP	Yes	No	Gateway South Project – Segment #2 (2024)
	Aeolus	Anticline	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segments 2&3 (2020)
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie (2020)
	Anticline	Populus	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #4 (2024)
	Populus	Borah	500 kV	1	LTP	Yes	No	Gateway West Segment #5 (2024)
	Populus	Cedar Hill	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #7 (2024)
	Antelope	Goshen	345 kV	1	LTP	Yes	No	Nuclear Resource Integration (2026)
	Antelope	Borah	345 kV	1	LTP	Yes	No	Nuclear Resource Integration (2026)
	Windstar	Aeolus	230 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #1W (2024)
	Oquirrh	Terminal	345 kV	2	LTP	Yes	Yes	Gateway Central
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with Idaho Power) (2024)
	Shirley Basin	Standpipe	230 kV	1	LTP	Yes	No	Local Wind Integration (2020)
PacifiCorp West	Wallula	McNary	230 kV	2	LTP	Yes	Yes	Gateway West Segment A (2020)
Portland General	Blue Lake	Gresham	230 kV	1	LTP	No	Yes	New Line (2018)
	Blue Lake	Troutdale	230 kV	1	LTP	No	Yes	Rebuild (2018)
	Blue Lake	Troutdale	230 kV	2	LTP	No	Yes	New Line (2018)
	Horizon	Springville Jct	230 kV	1	LTP	No	Yes	New Line (Trojan-St Marys-Horizon) (2020)
	Horizon	Harborton	230 kV	1	LTP	No	Yes	New Line (re-terminates Horizon Line) (2020)
	Trojan	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	St Marys	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	Rivergate	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	Trojan	Harborton	230 kV	2	LTP	No	Yes	Re-termination to Harborton (2020)
			115 kV	1	LTP	No	Yes	Various Load Service Additions (2019-2024)

Table 4 – New Transmission Projects

Transmission Service Obligations: Listed below, in Table 5, are the transmission obligations that were submitted for the 2018-2019 planning cycle.

[14] Regionally significant transmission projects are generally those that effect transfer capability between areas of NTTG. Projects that are mainly for local load service are not regionally significant. Projects that are not regionally significant will be placed into all change cases and not tested for impact on the Regional Transmission Plan. The facilities submitted in the LTP's will be removed in the Null Case

Submitted by	MW[15]	Start Date	POR	POD
Idaho Power	500/200	2021	Northwest	IPCo
	250/550	2022	LGBP	BPASEID

Table 5 – Transmission Service Obligations

Available Transfer Capability (ATC): Listed in Table 6 is a summary of the transmission path ratings and Available Transfer Capability (ATC) on the designated transmission path(s).

Path Name	Existing Path Rating (MW)	Available Transfer Capability(*2018*)
8 – Montana to Northwest	E-W: 2200 W-E: 1350	E-W: 627* W-E: 666**
14 - Idaho to Northwest	W-E: 1200 E-W: 2175	W-E: 0 E-W: 1489
16 – Idaho - Sierra	N-S: 500 S-N: 360	N-S: 448 S-N: 0
17 – Borah West	E-W: 2557 W-E: 1600	E-W: 26* E-W: 0** W-E: 1350
18 – Idaho to Montana	N-S: 383 S-N: 256	N-S: 0 S-N: 131
19 – Bridger West	E-W: 2400 MW W-E: 1266 MW	E-W: 86* W-E: 250* E-W: 0** W-E: 0**
20 – Path C	N-S: 1600 S-N: 1250	N-S: 0 S-N: 0
37 - TOT 4A	NE-SW: 950	NE-SW: 0 SW-NE: 0
38 - TOT 4B	SE-NW: 829	SE-NW: 0 NW-SE: 0
75 - Hemingway-Summer Lake	E-W: 1500 W-E: 550	E-W: 150* E-W: 0** W-E: 0**
80 – Montana Southeast	N-S: 600 S-N: 600	N-S: 600 S-N: 385
83 – MATL	N-S: 300 S-N: 300	N-S: 300 S-N: 0

Path 8 Notes:

* This includes 184 MW owned by BPA which ties into the same Garrison substation as some of the other capacity.

** This number is the ATC on the NorthWestern or Eastern side of the meter points. West of the meter points belongs to BPA and Avista and will have different values.

Path 17, 19 and 75 Notes:

* IPCo Share.

** PAC Share

Table 6– Transmission Path Capacity and Available Transfer Capability

Interregional Transmission Projects: Table 7 below provides a list of the Interregional Transmission Projects (ITPs) received in Q1 that satisfied the NTTG submission and information requirements.

[15] Summer/Winter service requirements

SUMMARY OF Q1-2018 INTERREGIONAL PROJECTS SUBMITTED TO NTTG						
Project Name	Company	Relevant Planning Region(s)	Termination From	Termination to	Status	In Service Date
Cross-Tie Transmission Project	TransCanyon, LLC	NTTG, WestConnect	Clover, UT	Robinson Summit, NV	Conceptual	2024
SWIP-North[16]	Great Basin Transmission LLC	CAISO[17], NTTG, WestConnect	Midpoint, ID	Robinson Summit, NV	Permitted	2021
TransWest Express Transmission DC/AC Project18	TransWest Express, LLC	CAISO, NTTG, WestConnect	Rawlins, WY	Boulder City, NV	Conceptual	2022
TransWest Express Transmission DC Project[18]	TransWest Express, LLC	CAISO, NTTG, WestConnect	Rawlins, WY	Boulder City, NV	Conceptual	2022

Table 7 – Interregional Transmission Projects

D. Transmission Needs Driven by Public Policy Requirements

Public Policy Requirements are those requirements that are established by local, state, or federal laws or regulations.

Local transmission needs driven by Public Policy Requirements are included in the NTTG Initial Regional Plan[19] through the Local Transmission Plans of the NTTG Transmission Providers and included in NTTG's planning process. Additionally, during Quarter one, stakeholders may submit regional transmission needs and associated facilities driven by Public Policy Requirements to be evaluated as part of the preparation of the Draft Regional Transmission Plan.

The selection process and criteria for regional projects meeting transmission needs driven by Public Policy Requirements are the same as those used for any other regional project chosen for the Regional Transmission Plan.

During this planning cycle, no additional transmission needs, beyond those submitted by the transmission providers, were submitted to satisfy Public Policy Requirements. A full listing of applicable Public Policy Requirements for the NTTG footprint is included in Appendix A. The following Renewable Portfolio Standard ("RPS") values were used in the modeling for the 2018-2019 study:

[16] The SWIP-North project submitted by Great Basin Transmission (GBT) requires a new physical connection at Robinson Summit, at the southern end of the Project. To transmit power beyond the Project, ~1,000 MW of capacity rights on the already in-service ON Line Project from Robinson Summit to Harry Allen 500 kV, as well as, completion of CAISO's Harry Allen to Eldorado Project in 2020, those GBT capacity rights will provide a CAISO access to SWIP-North.
[17] CAISO has volunteered to participate in the studies and accept cost allocation.
[18] Two Alternatives were submitted by TransWest Express, 1) a DC Line the entire Length, and 2) a DC line from Wyoming to the Intermountain Power Project area then an AC line to Nevada.
[19] See Attachment K, Local Planning process

	ADS 2028 case
California	33%
Oregon	27%
Washington	15%
Idaho	-
Montana	15%
Wyoming	-
Utah	20%
Nevada	25%
Arizona	25%
Colorado	30%
New Mexico	20%

Table 8 – RPS Assumptions in Production Cost Model Dataset[20]

E. Development of Initial Regional Transmission Plan

The planning process started by developing the Initial Regional Transmission Plan through a bottom up approach by aggregating the Funding TPs' local transmission plans into a single regional transmission plan. Next the IRTP Non-Committed projects within the NTTG geographical area were analyzed through Change Case plans to determine whether Alternative Projects could be added or substituted and/or one or more Non-Committed projects could be deferred to yield a regional transmission plan that would be more efficient or cost effective than the IRTP. It is the result of this analysis that formulated the dRTP presented herein. This dRTP document discusses in detail the activities and studies completed and how the dRTP was developed.

III. Study Methodology

To determine the more efficient or cost-effective transmission plan that would become the dRTP, both reliability and economic studies were performed in accordance with the 2018-2019 Study Plan. The reliability studies utilized production cost modeling and power flow studies. The production cost model results (the base case input data derived from the WECC 2028 Anchor DataSet (ADS) case[21] were used to identify nine stressed hours. After review of the cases, eight were subjected to reliability analysis using a power flow model. The input and output data for these selected hours were transferred, using the round-trip process, from the production cost model (i.e., GridView) to a power flow model (i.e., PowerWorld) to perform the technical reliability analysis. The economic studies that were performed next utilized the Attachment K's

[20] The ADS case was developed prior to California passing Senate Bill 100.
[21] See Appendix B that lists the resource additions and removals made to the production cost model and power flow Change Cases.

three metrics (i.e., capital related costs, energy losses, and reserves) to analyze those Change Case plans that were reliable to further determine the cost effectiveness of the NTTG transmission plan. The reliability study process and the economic evaluations will be described in more detail below.

A. Production-Cost Modeling

GridView[22] production cost software was used to look at 8760 hours of data to determine stressed conditions within the NTTG footprint. The production cost dataset representing the year 2028 was obtained from the 2028 ADS case of the Western Electricity Coordinating Council ("WECC"). This case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system ten years into the future. The 2028 ADS case was released on July 1st, 2018. Members of the TWG reviewed the loads, resources, and transmission data for their transmission planning area to ensure that the representations in this case were reasonably close to the data they had submitted in the first quarter of the biennial cycle. TWG identified the need to incorporate a significant number of corrections prior to use by NTTG. In early September, NTTG shared these changes with the other Regional Planning entities and WECC for inclusion in their future studies. The TWG then agreed to use this modified ADS case in creating the stressed cases discussed below.

TWG determined that there were eight stressed conditions which impact the NTTG area that should be studied:

- high NTTG summer peak;
- high NTTG winter peak;
- high eastbound Idaho-Northwest flows;
- ~~high southern Idaho-Northwest export (Idaho-Northwest westbound);~~[23]
- high NE-SE (Path Tot2)/COI/PDCI flows;
- high Wyoming Wind production;
- high Borah West flows;
- high NTTG footprint import; and;
- high Aeolus West and South flows.

After running all 8760 hours using the GridView production-cost program, the data was analyzed and the hours representative of the stressed conditions were identified. The hours are shown in Table 9 below.

[22] GridView is a registered ABB product
[23] Case dropped from study after review of the exported case.

Stressed Condition	Date	Hour	TWG Label
Max. NTTG Summer Peak	July 19, 2028	16:00	A
Max. NTTG Winter Peak	December 5, 2028	19:00	B
High eastbound Idaho-Northwest flows	June 3, 2028	2:00	C
~~High westbound Idaho-Northwest flows~~[24]	~~October 11, 2028~~	~~11:00~~	~~D~~
High Tot2/COI/PDCI Flows	May 16, 2028	19:00	E
High Wyoming Wind	February 24, 2028	Midnight	F
High Borah West Flows	December 11, 2028	2:00	G
High NTTG Footprint Import	July 27, 2028	14:00	H
High Aeolus West and South flows	June 3, 2028	18:00	I

Table 9 – Hours Selected from 2028 WECC ADS Case to Represent Different NTTG System Stresses

B. Power Flow Cases

The next step in the process was developing the power flow stressed condition cases by converting (i.e., a "round-trip process") the production cost model for the above hours into the PowerWorld power flow cases. It should be noted that this conversion process has improved with each biennial cycle from months to weeks to now a few hours, once the initial dataset has been adjusted.

The TWG determined that the power flow model loads extracted from the production cost model did not stress the transmission system as much as historical conditions would suggest. Further exploration found that the production cost database uses a 1 in 2 load forecast[7] and when extracting a single hour from the production cost model to the power flow model, this single hour may not represent a coincident peak hour [25] between the balancing areas as has been experienced in the past. TWG recognized that these differences result in lower than expected peak loads in the extracted power flow for a number of the balancing areas within NTTG. To better reflect possible highly stressed conditions for the selected peak loads within the NTTG footprint, the balancing area loads in the powerflow model were adjusted to get each area's non-coincident peak loads that represent 1 in 5[7] peak load condition. These load adjustments were only applied to the summer and winter peak powerflow cases.

[24]The flow pattern extracted for this case did not meet the objectives for this case, so further study of the case was dropped.
[25]This refers to demand among a group of customers that coincides with total demand on the system at that time. Residential demand at a time of peak industrial demand can be referred to as coincident peak demand, as can a particular plant's demand at a time of peak demand across the whole system.

			PacifiCorp		
	Idaho	Northwestern	PACW	PACE	Portland
Non-Coincident Peak	4259	2027	3769	10387	4006
2028 Coincident Peak	4190	1936	3395	10387	2958
Coincident Peak %	98.4%	95.5%	90.1%	100.0%	73.8%
Relative Scaling Factors					
1 in 2	100%	100%	100%	100%	100%
1 in 5	102.7%	100%	102.0%	102.0%	103.2%
1 in 10	103.6%	100%	104.6%	104.6%	104.9%
1 in 5 Target MW	4375	2027	3844	10595	4133
Target/2028 Peak	104.4%	104.5%	113.2%	102.0%	139.7%
Applied	105%	105%	113%	102%	125%

Table 10 – Summer Peak Hour Adjustment

			PacifiCorp		
	Idaho	Northwestern	PACW	PACE	Portland
Non-Coincident Peak	2901	1872	3957	8083	3830
2028 Coincident Peak	2572	1821	3624	7984	3777
Coincident Peak %	88.7%	97.3%	91.6%	98.8%	98.6%
Relative Scaling Factors					
1 in 2	100%	100%	100%	100%	100%
1 in 5	102.7%	100%	102.0%	102.0%	105.0%
1 in 10	103.7%	100%	104.6%	104.6%	107.8%
1 in 5 Target MW	2978	1872	4036	8245	4022
Target/2028 Peak	115.8%	102.8%	111.4%	103.3%	106.5%
Applied	113%	105%	115%	103.5%	109%

Table 11 – Winter Peak Hour Adjustment

Each of the stressed cases was then reviewed by the TWG to ensure that the case met steady state system performance criteria (no voltage issues or thermal overloads). Bubble diagrams showing the inter-area flows for each of the stressed cases are included in the result sections below.

C. System Performance Criteria

The details of the system performance criteria can be found in the Study Plan (see Study Plan footnote 10). An abbreviated summary of the NERC reliability criteria:

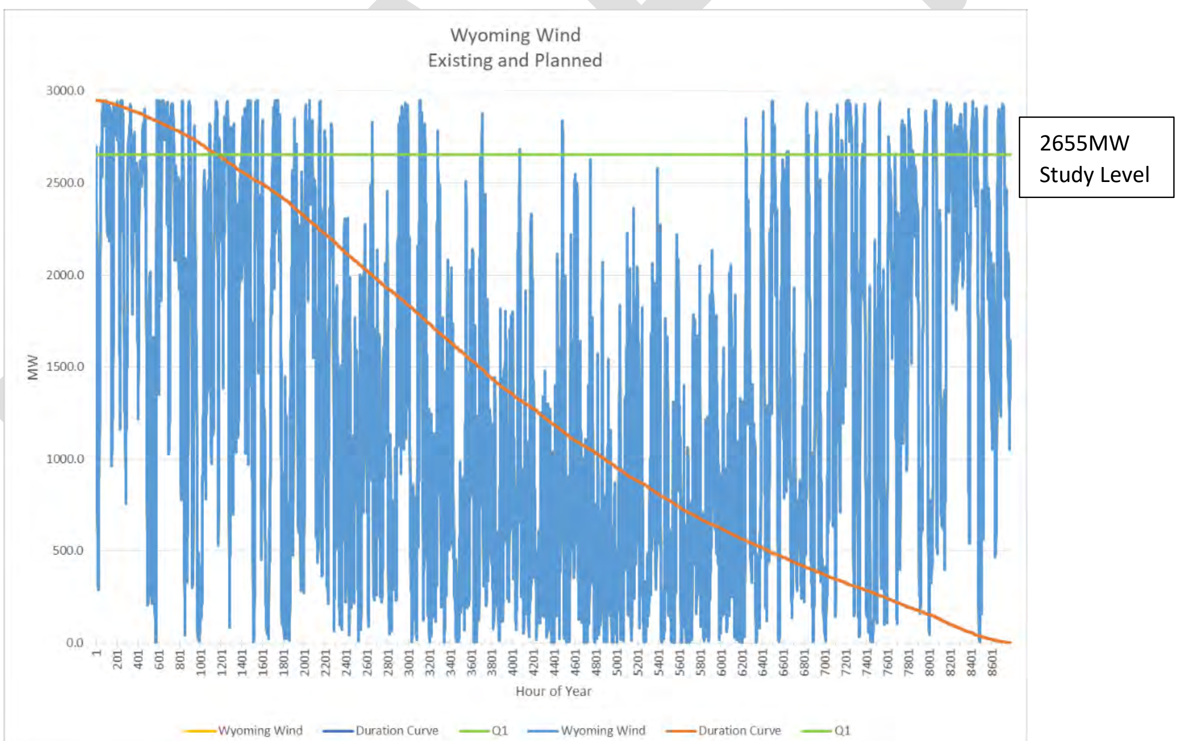
- Lines and transformers must not exceed their normal thermal ratings during steady state conditions;
- Line and transformers must not exceed their emergency thermal ratings post contingency;
- Bus voltages must remain within the following ranges:
  - For steady-state conditions, bus voltages must be between 95% and 105% for buses 345 kV and below and between 100% and 110% for buses 500 kV and above.

- o Post contingency voltages must be > 90% and < 110% for buses 345 kV and below and be greater than 95% and less than 115% for buses 500 kV and above.

For dynamic studies, the criteria are based on TPL-001-WECC-CRT-3, following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for each BES bus serving load and shall not dip below 70% for more than 30 cycles nor remain below 80% for more than 2 seconds once the voltage has recovered above 80% post fault. All oscillations shall be positively damped within 30 seconds or the contingency will be considered unstable.

D. Simultaneous Wind Production in Wyoming

Figure 4 shows a peak duration curve of those existing and planned resources based on data developed by National Renewable Energy Laboratory (NREL) for the 2009 weather patterns. 2009 is the year selected by WECC to base all of the hourly profiles for load, average hydro conditions and fixed/non-dispatchable generation. TWG reviewed the duration curve in Figure 4 and selected a study level of 2655 MW or approximately 90%[26] of the peak capacity of the existing and forecasted wind resources to be installed. Based on the NREL models, production would exceed this level about 1020 hours or over a month. The time of year, time of day and the associated load level of the high wind scenario will also be reflective of the most likely occurrence of the high wind scenario as indicated in Figure 4.



[26] The peak installed capacity of the Wyoming wind is 3177 MW, however, some of that nameplate capacity is limited. The maximum coincident production is limited to 2950 MW. The value selected was 90% of the maximum coincident production.

Figure 4: Chronologic and Duration curve of forecasted Wyoming wind production for 2028

IV. Stress Conditioned Case Study Results

After analyzing the steady-state performance of each of the nine stress conditioned cases, the TWG performed a rigorous contingency analysis on eight of the nine cases[27]. This contingency analysis consisted of over 445 single contingencies and 36 credible double contingencies, to determine if each contingency meets the system performance criteria. If there were reported reliability violations by the power flow program, TWG determined if these violations were legitimate and needed mitigation to correct the violation or if modeling problems (e.g., corrections to the modeled contingency actions) caused the reliability violation. For the legitimate violations, TWG determined what additional facilities would be needed to meet the criteria and adjust the IRTP to include the additional facilities. If no violations were found, then the facilities in the IRTP are deemed adequate for serving the NTTG loads and resources in the year 2028. Table 12 provides a summary of the NTTG footprint L&R balance for each of the conditions studied.

The Null Case topology indicates for cases E, F, G and I, that system performance is inadequate without transmission system additions by 2028 to meet NTTG's requirements.

		Case A	Case B	Case C	Case D	Case E	Case F	Case G	Case H	Case I
Idaho	Gen	2828	2373	1367	1257	1909	1178	943	2493	1837
	Load	4388	2978	2478	2053	2755	1777	1926	3720	2594
	Losses	150	83	157	61	126	151	152	106	139
	Import/Export	-1710	-688	-1268	-857	-972	-750	-1136	-1333	-896
Montana	Gen	2505	2446	1931	1429	3419	2297	2125	2243	2611
	Load	2027	1870	1071	1374	1302	1304	1385	1564	1310
	Losses	109	68	60	58	118	76	63	60	67
	Import/Export	369	507	800	-3	1999	917	677	620	1234
PACE	Gen	10011	10013	4619	9986	8755	9727	8719	7900	7742
	Load	9957	8243	4876	6137	6547	4606	4608	8825	6142
	Losses	337	331	176	425	414	415	382	255	365
	Import/Export	-282	1438	-433	3425	1794	4707	3729	-1181	1236
PACW	Gen	2072	1759	848	1205	1262	1058	1016	1438	819
	Load	3643	4036	1496	2618	2307	2148	2350	3466	2110
	Losses	72	87	57	54	67	57	62	65	50
	Import/Export	-1643	-2364	-705	-1466	-1112	-1147	-1397	-2093	-1342
PGN	Gen	2540	2084	932	1408	1044	1624	1879	1675	866
	Load	3527	4022	1664	2587	2303	2383	2213	3297	2130
	Losses	67	63	34	37	40	32	36	44	33
	Import/Export	-1054	-2001	-767	-1216	-1300	-792	-370	-1666	-1298
NTTG	Gen	19957	18676	9697	15286	16389	15883	14682	15750	13875
	Load	23542	21149	11586	14768	15214	12218	12482	20872	14287
	Losses	735	633	484	635	766	731	696	530	655
	Import/Export	-4946	-3733	-2662	-407	-191	2343	972	-6267	-1624

[27] TWG dropped further study of Case D since the case did not achieve the desired case objectives, see section IV-D.

Table 12: L&R Balance summary of selected cases

The results of each of the stressed cases are discussed below:

A. NTTG Summer Peak Case

This case has an NTTG summer peak load of 23,542 MW with 19,331 MW of generation. The sum of the NTTG boundary flows in the case is approximated by taking the difference between generation and load, which equated to 4,946 MW (import). A bubble diagram of the case is shown below.

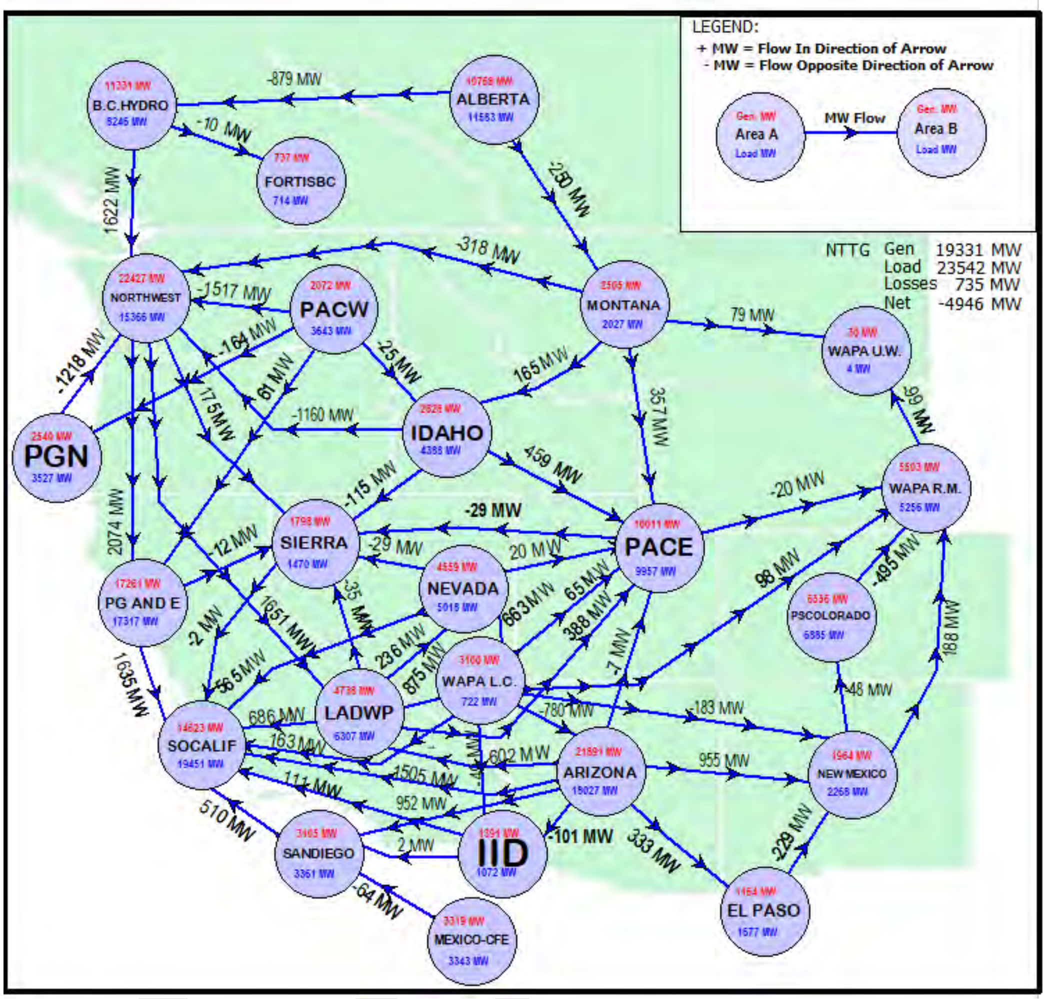


Figure 5 - Tie-line flows for Summer Peak Case
(July 19, 2028 Hour 16 - NTTG Case A)

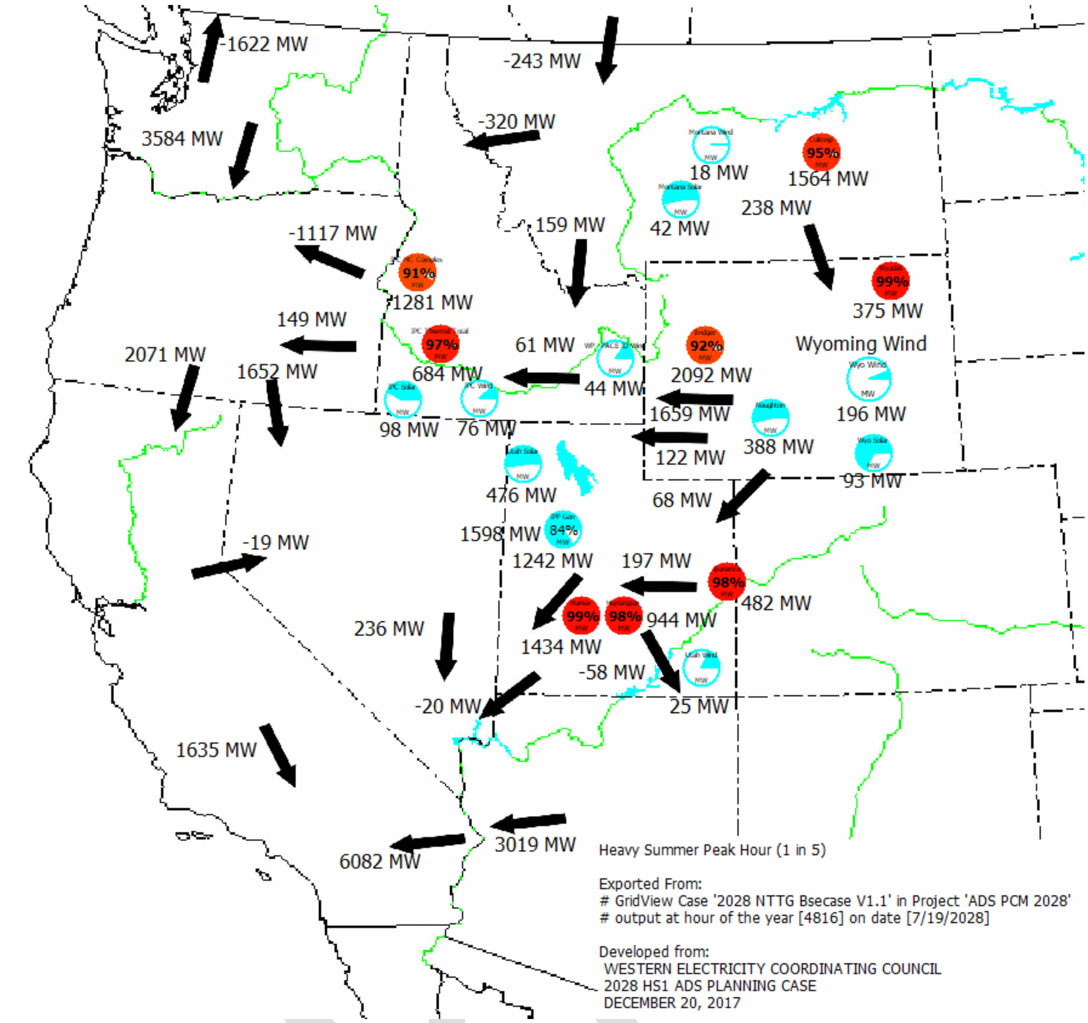


Figure 6 – Other flows for Summer Peak Case
(July 19, 2028 Hour 16 - NTTG Case A)

This summer peak case represents a 1 in 5 NTTG footprint peak load. The original exported case from the PCM was a 1 in 2 condition based on the assumptions of that dataset. Data was collected from each data submitter to adjust the load forecast from 1 in 2 to the 1 in 5 condition. Each area's load was independently adjusted to achieve the 1 in 5 condition.

In this case, the both the pRTP and the IRTP performed reasonably well with a few local areas having known existing issues that have not risen to the level of justifying expenditures to resolve them.

B. NTTG Winter Peak Case

The NTTG winter peak load in this case is 21,149 MW with a total of 18,050 MW of generation. The difference of generation and load approximates the boundary flow which is equal to 3,733 MW (import). Only a few local system violations occur in the pRTP case

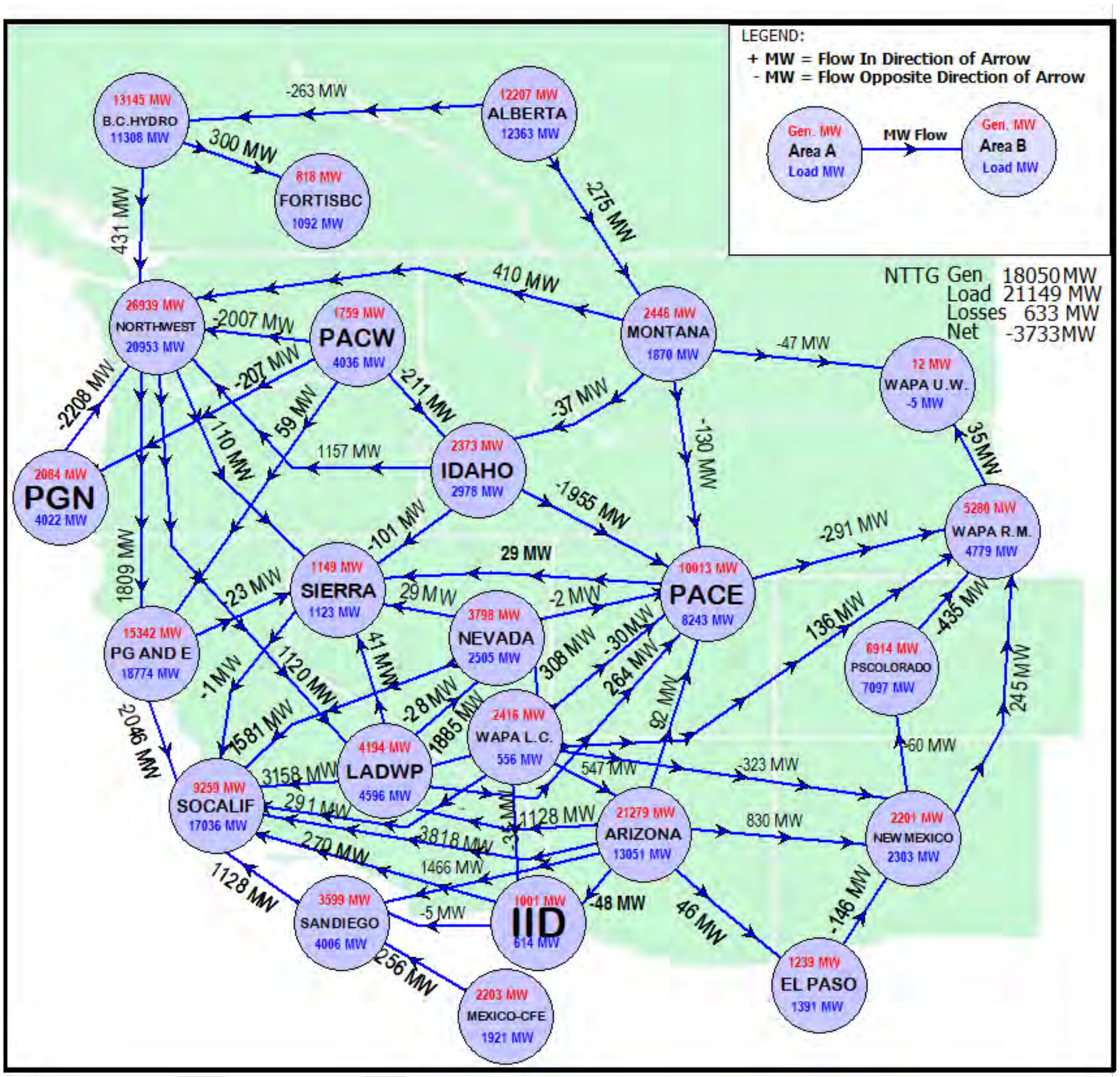


Figure 7 - Tie-line flows for Winter Peak Case
(Dec 5, 2028 Hour 19 - NTTG Case B)

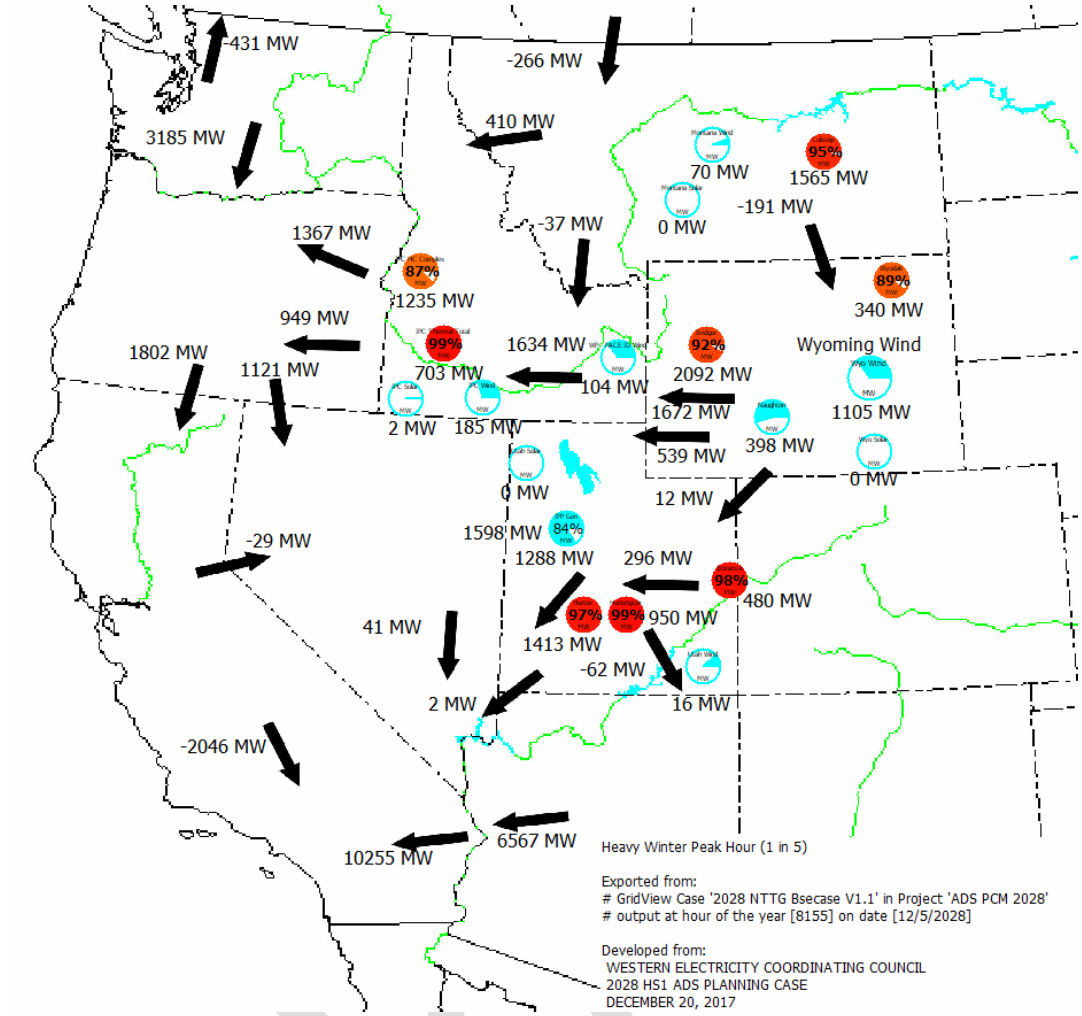


Figure 8 - Other flows for Winter Peak Case (Dec 5, 2028 Hour 19 - NTTG Case B)

Similar to the Summer Peak case (Case A), the exported winter peak case was adjusted to reflect a 1 in 5 condition.

C. High Eastbound flows on Idaho-Northwest Path

This case has an Idaho-Northwest Path flow of 1970 MW eastbound. The NTTG total is approximately 2,662 MW (import). The NTTG load and generation in this case are 11,586 MW and 9,408 MW respectively. The bubble diagram follows.

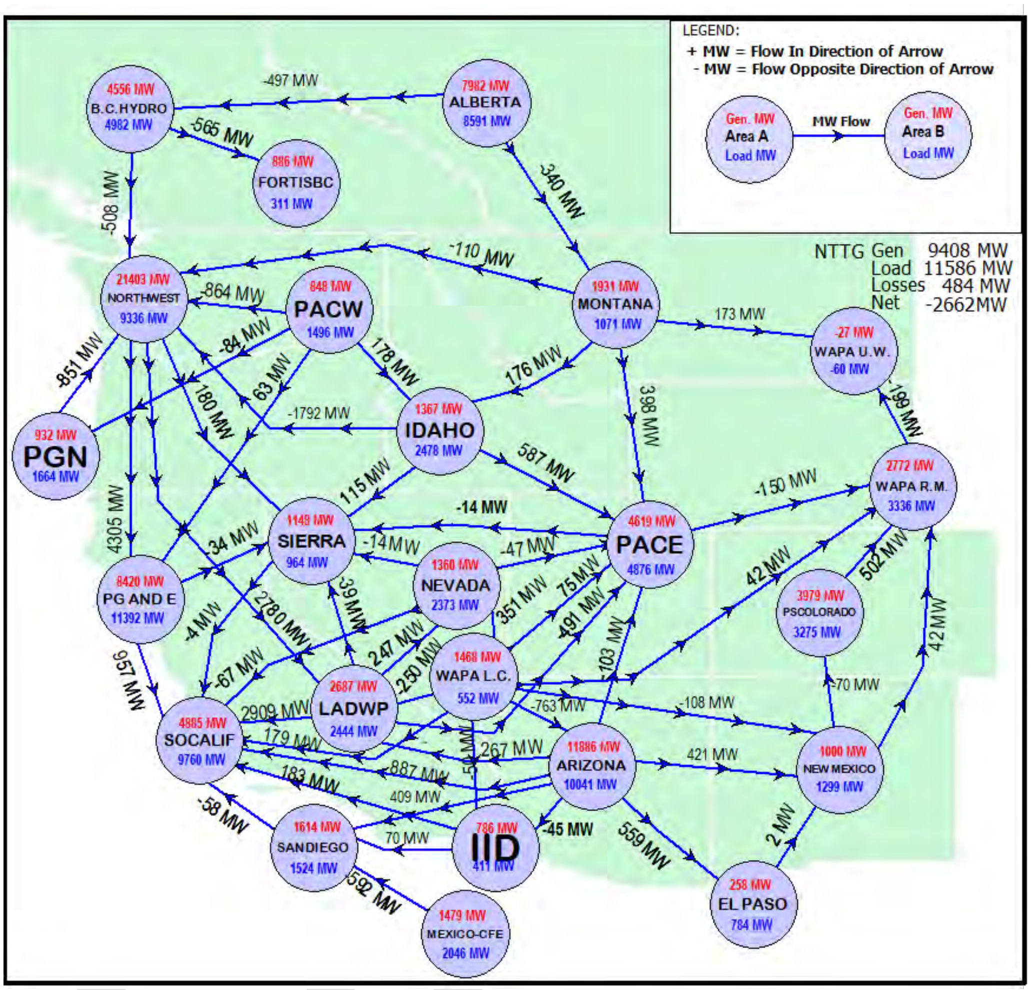


Figure 9- Tie-line flows for high eastbound Idaho-Northwest Path Case (June 3, 2028 Hour 2 - NTTG Case C)

The existing Idaho-Northwest import capability is 1200 MW. The PCM dataset result[28] there were 128 hours that exceeded that level, principally in the May-July time period.

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[28] The PCM dataset is based upon a 2009 average year condition. The dataset does not model contractual commitments, thus, the PCM cannot track ATC. The flows extracted from a PCM run are net flows (non-firm and Firm).

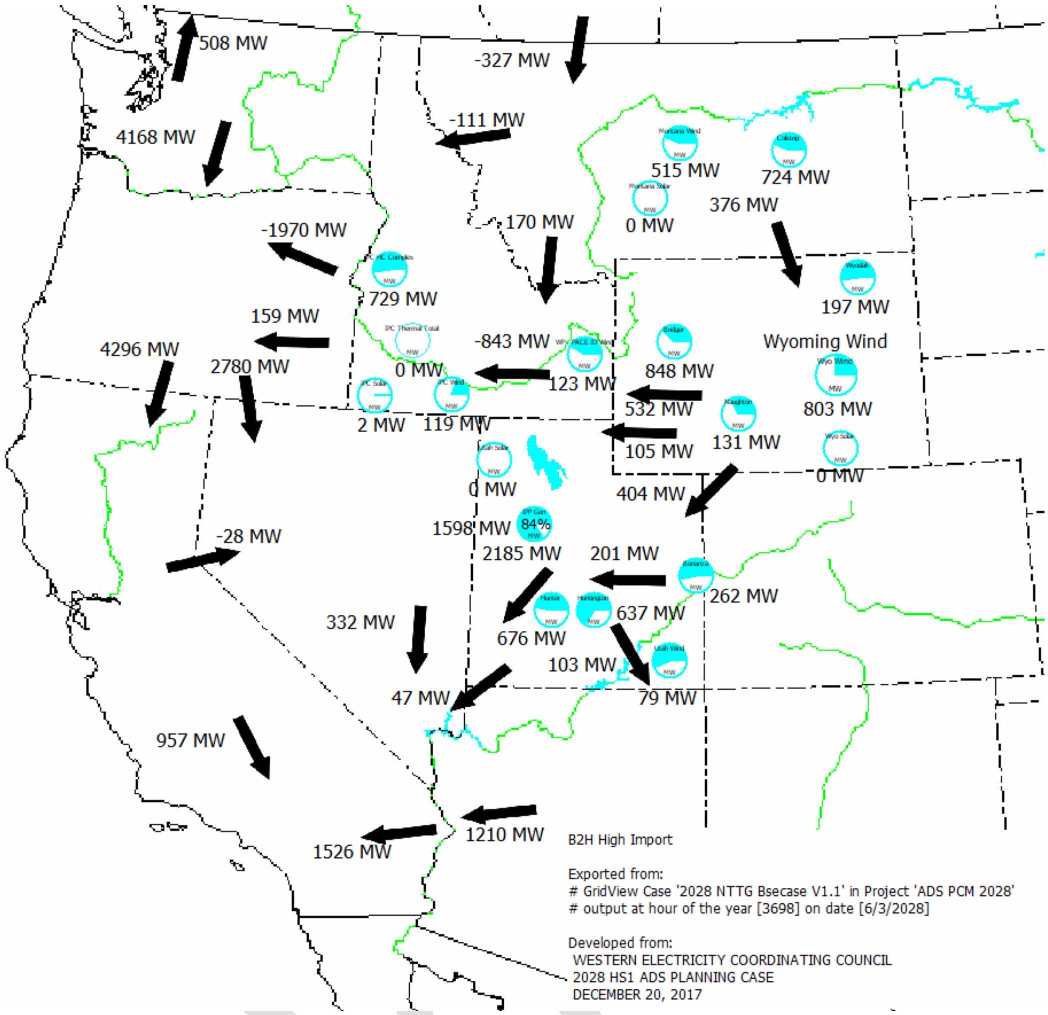


Figure 10 - Other flows for high eastbound Idaho-Northwest Path Case (June 3, 2028 Hour 2 - NTTG Case C)

D. High westbound Idaho-Northwest Case

This case was originally intended to study export conditions from Idaho to the Northwest. The exported case from the Production Cost Model was far below the desired condition in the Study Plan (1415 MW, where the target was in excess of 3000 MW). On further review the Technical Workgroup concluded to not analyze this case further.

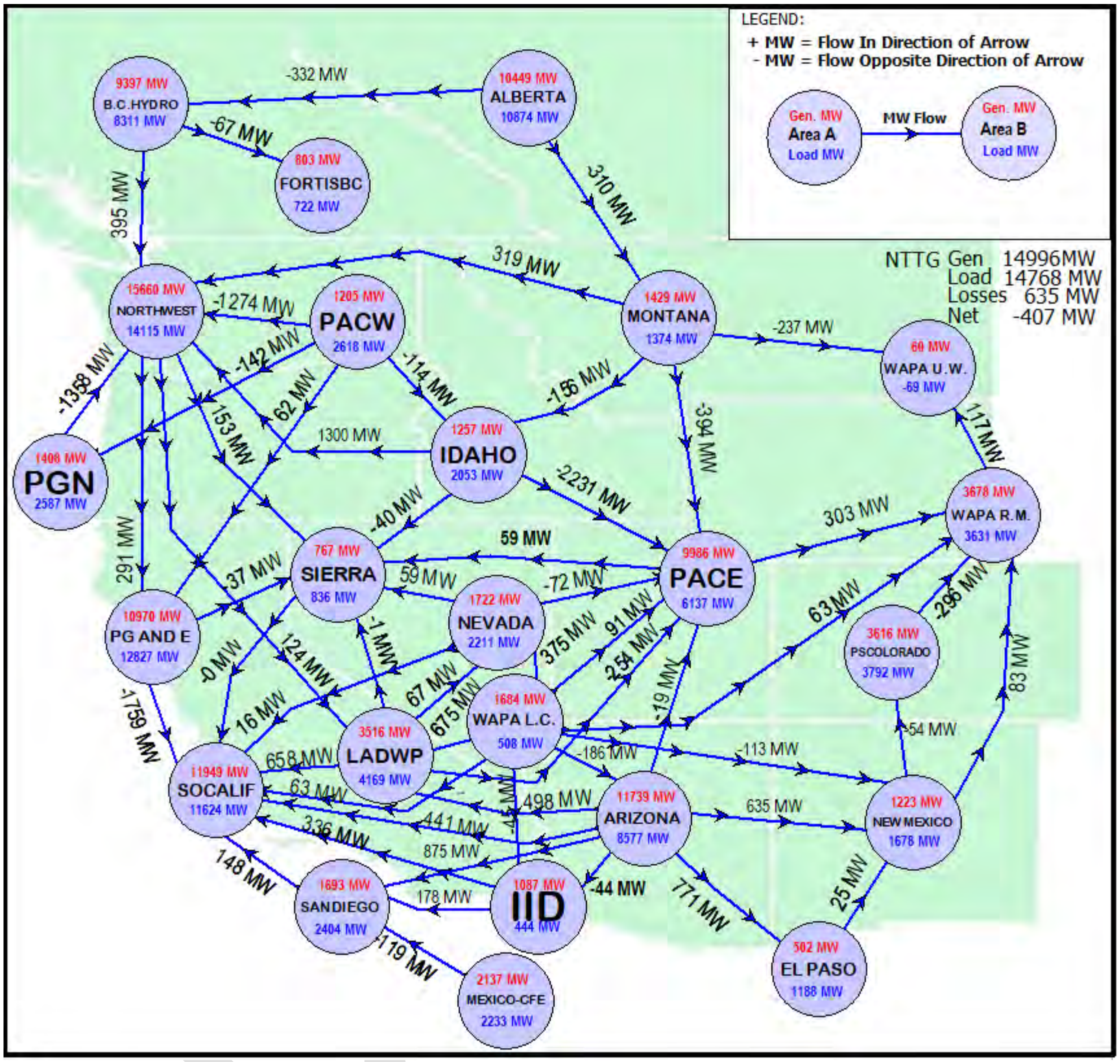


Figure 11 - Tie-line flows for High westbound Idaho-Northwest Case
(October 11, 2028 Hour 11 - NTTG Case D)

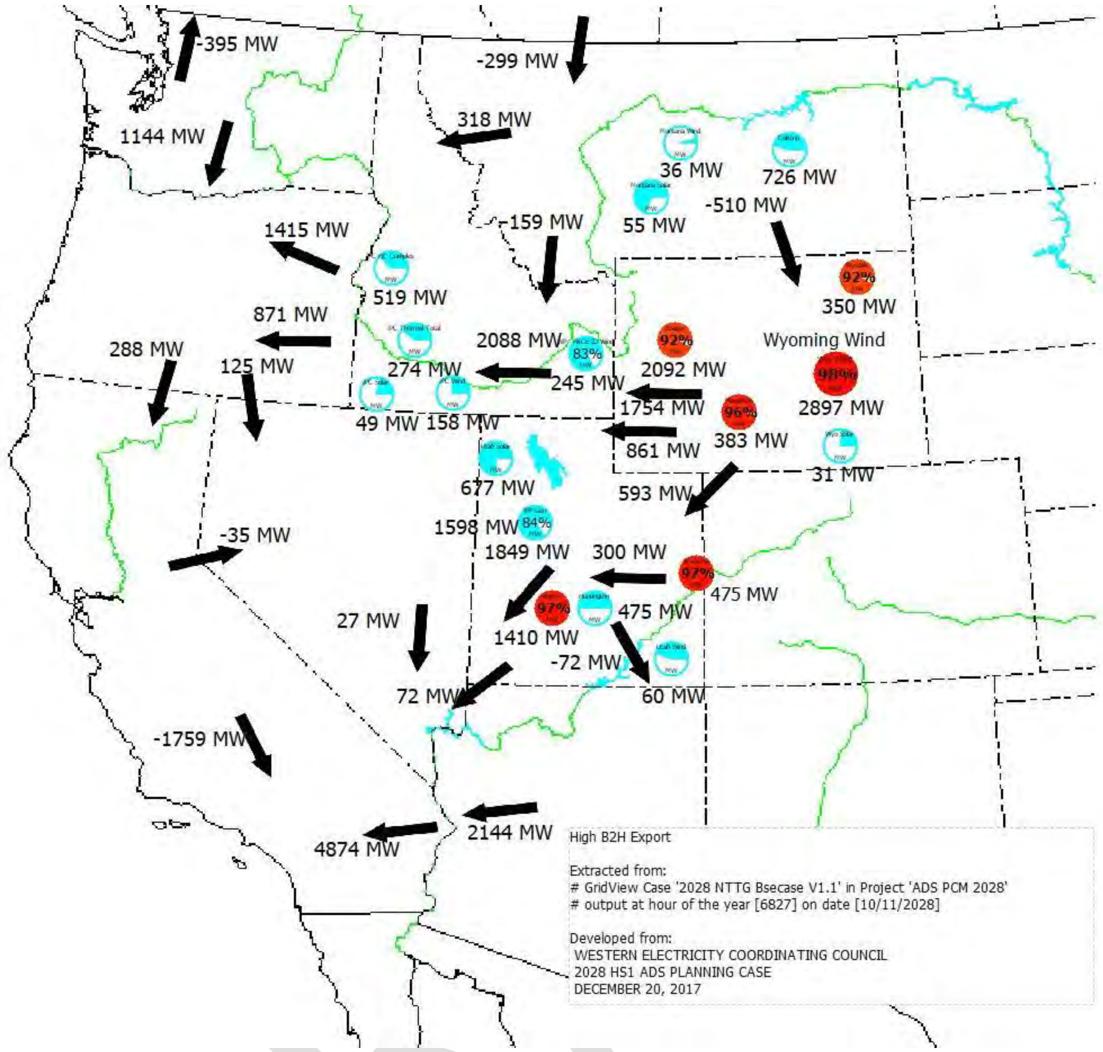


Figure 12 - Other flows for High westbound Idaho-Northwest Case (October 11, 2028 Hour 11 - NTTG Case D)

E. High Tot2/COI/PDCI Case

The NTTG load and generation are 15,214 MW and 15,789 MW respectively, with the NTTG footprint nearly balanced with a 191 MW import. The bubble diagram follows. The focus of this case is to evaluate the performance of the ITPs in supporting interregional transfers

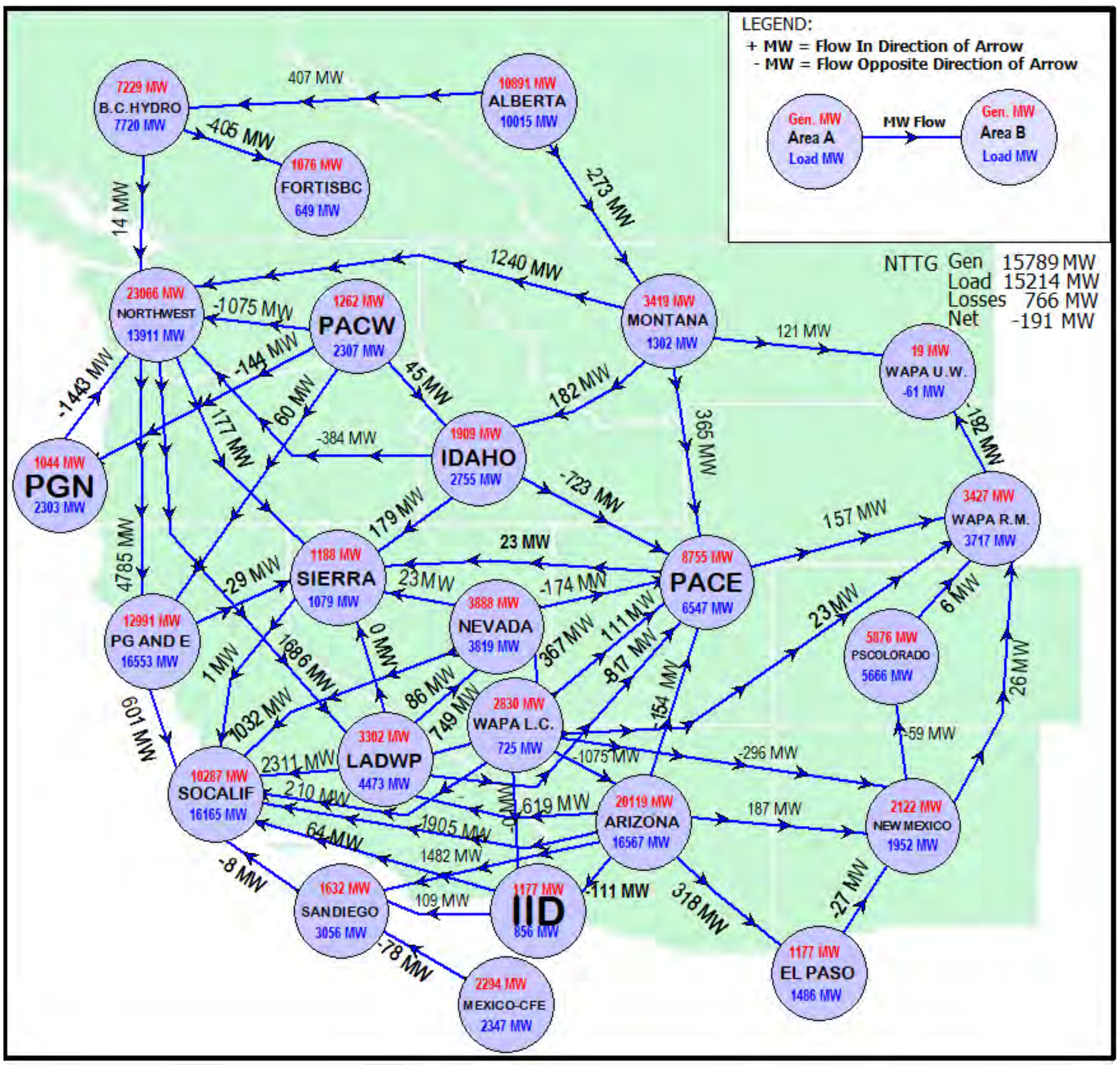


Figure 13 - Tie-line flows for High Tot2/COI/PDCI Case (May 16, 2028 Hour 19 - NTTG Case E)

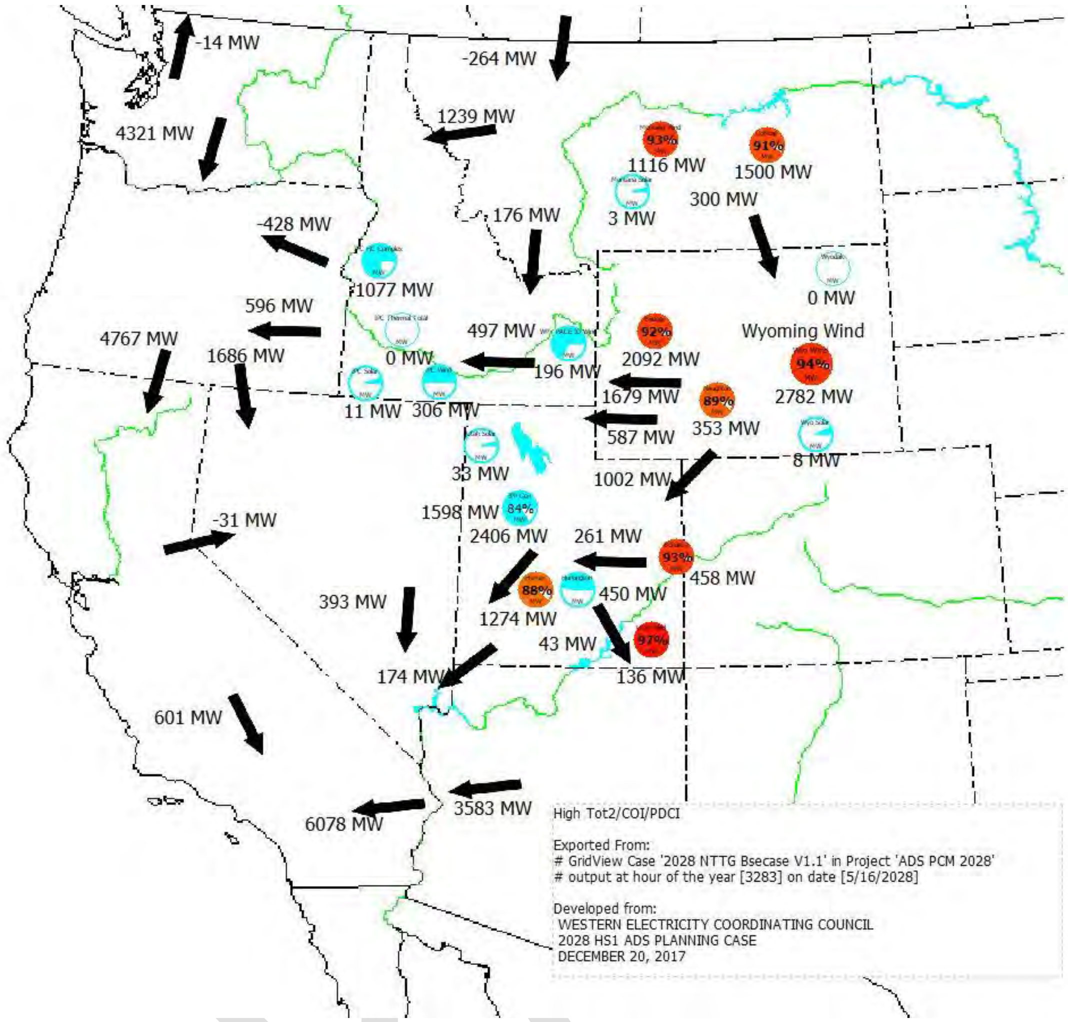


Figure 14 - Other flows for High Tot2/COI/PDCI Case
(May 16, 2028 Hour 19 - NTTG Case E)

The wind level in this case, 2782 MW, is likely to be exceeded 795 hours per year.

F. High Wyoming Wind Case

The NTTG load and generation in this case are 12,218 MW and 15,307 MW respectively with a NTTG export of 2,344 MW. The study plan target at 90% capacity factor was 2655 MW, the extracted case wind production was 2707 MW. The bubble diagram follows.

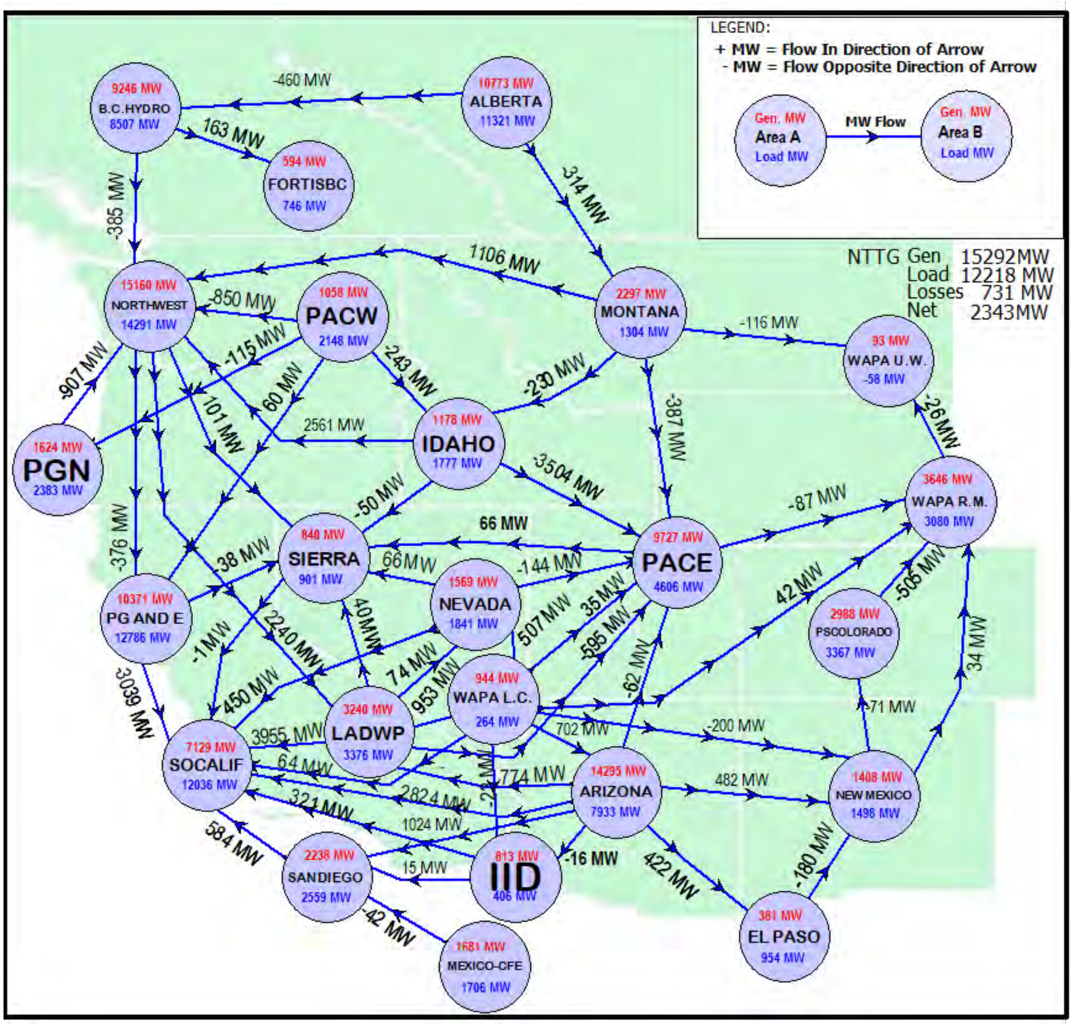


Figure 15 - Tie-line flows for High Wyoming Wind Case
(February 24, 2028 at Midnight - NTTG Case F

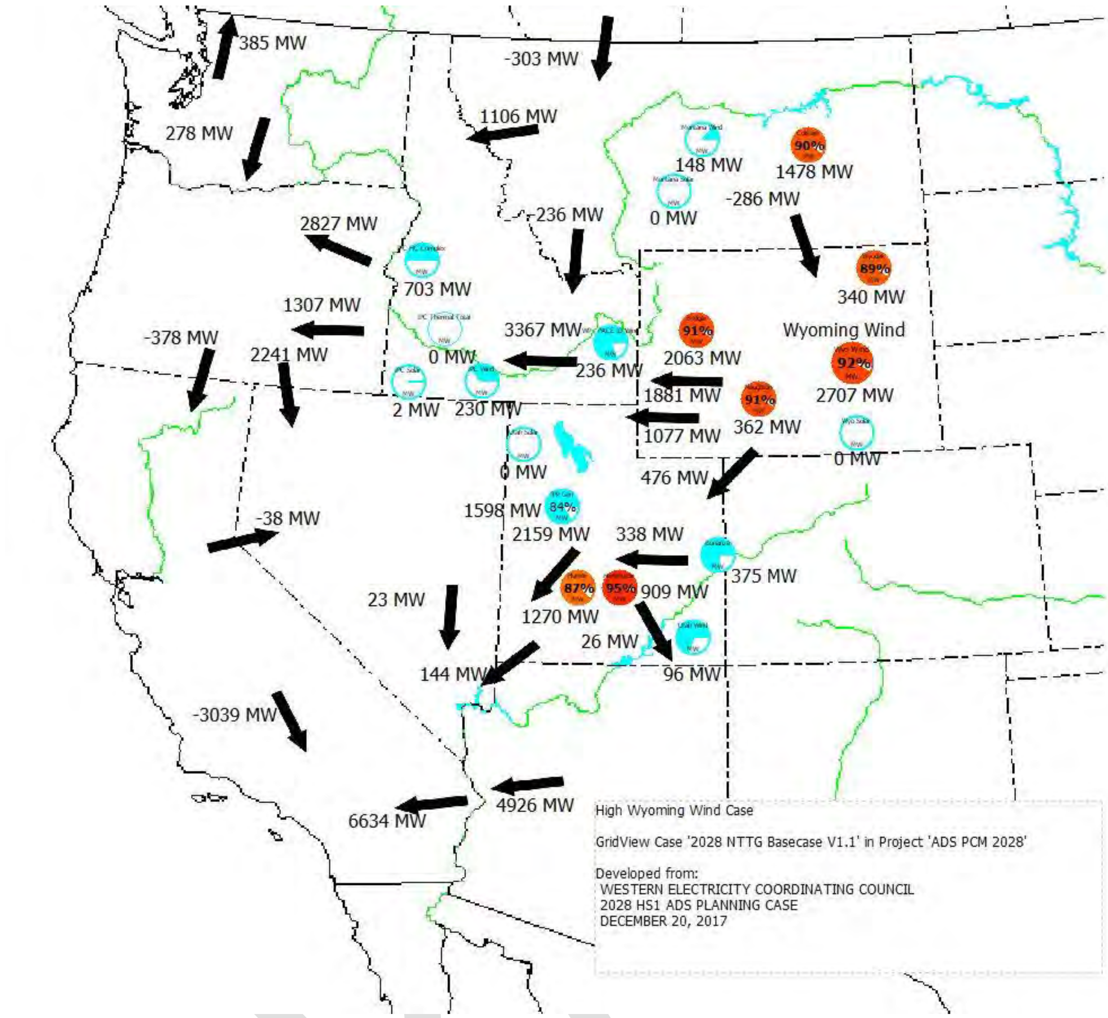


Figure 16 – Other flows for High Wyoming Wind Case
(February 24, 2028 at Midnight - NTTG Case F)

As described in Section IIID, the wind target of 2655 MW is approximately 90% of the existing and future peak wind production. This target level will be exceeded 1020 hours in an average year. This condition is more likely in the mid-September through May time period.

G. High Borah West Case

The NTTG load and generation in this case are 12,482 MW and 14,150 MW respectively with a NTTG export of 972 MW. The Borah West path flow is 3,403 MW. The present rating of the Borah West path is 2557 MW, any firm transfers above this level will require upgrades, without these upgrades, firm resources east of the cutplane could only serve east side firm loads. In the PCM results[22], the 2557 MW net flow level was exceeded 11 times. The bubble diagram follows.

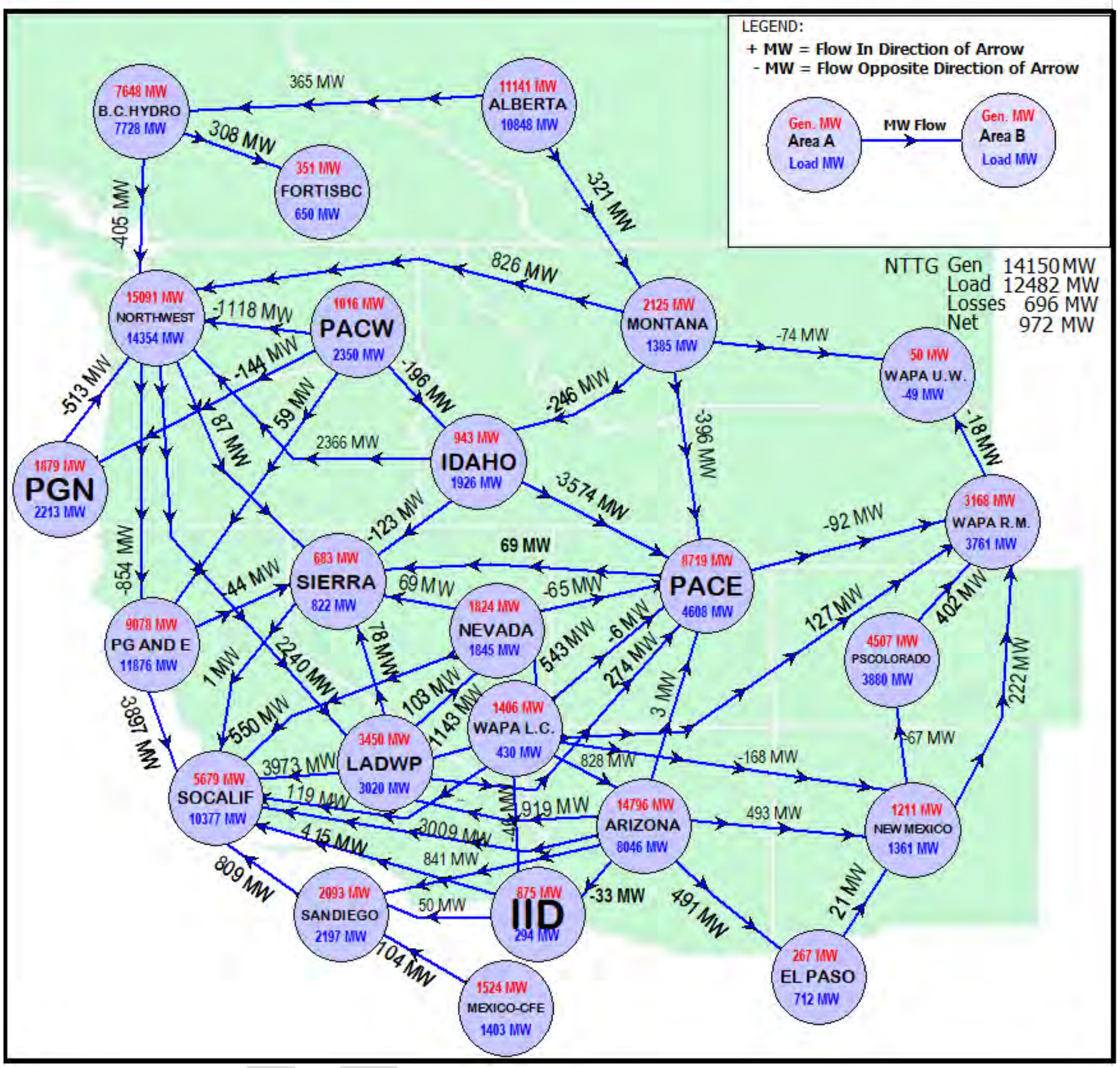


Figure 17 – Tie-line flows for High Borah West Case
(December 11, 2028 Hour 2 - NTTG Case G)

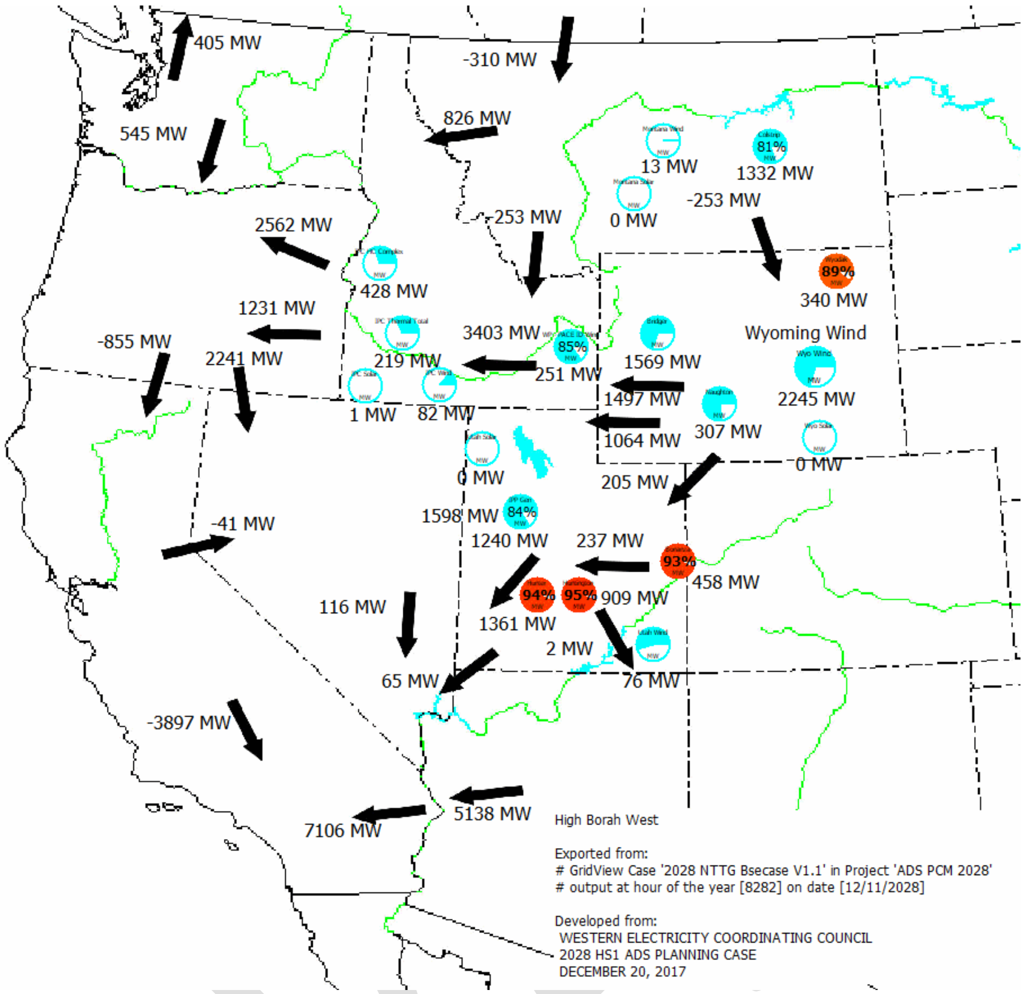


Figure 18 – Other flows for High Borah West Case (December 11, 2028 Hour 2 - NTTG Case G)

A second version of this condition was developed to test whether the Borah West flow condition was dependent on the export condition. The generation dispatch condition was reviewed and the following changes were made to the original G Case:

- Reduced/Turned Off:
  - Klamath Falls 515 MW
  - Port Westward 246 MW
  - Brownlee 177 MW
  - Hells Canyon 53 MW
  - Yale/Merwin 12 MW
- Increased:
  - Coulee 1026 MW

The resulting case is shown in Figure 19 and Figure 20, the case has been dispatched to a near neutral NTTG exchange. The Borah West flow increased 35 MW to 3,438 MW.

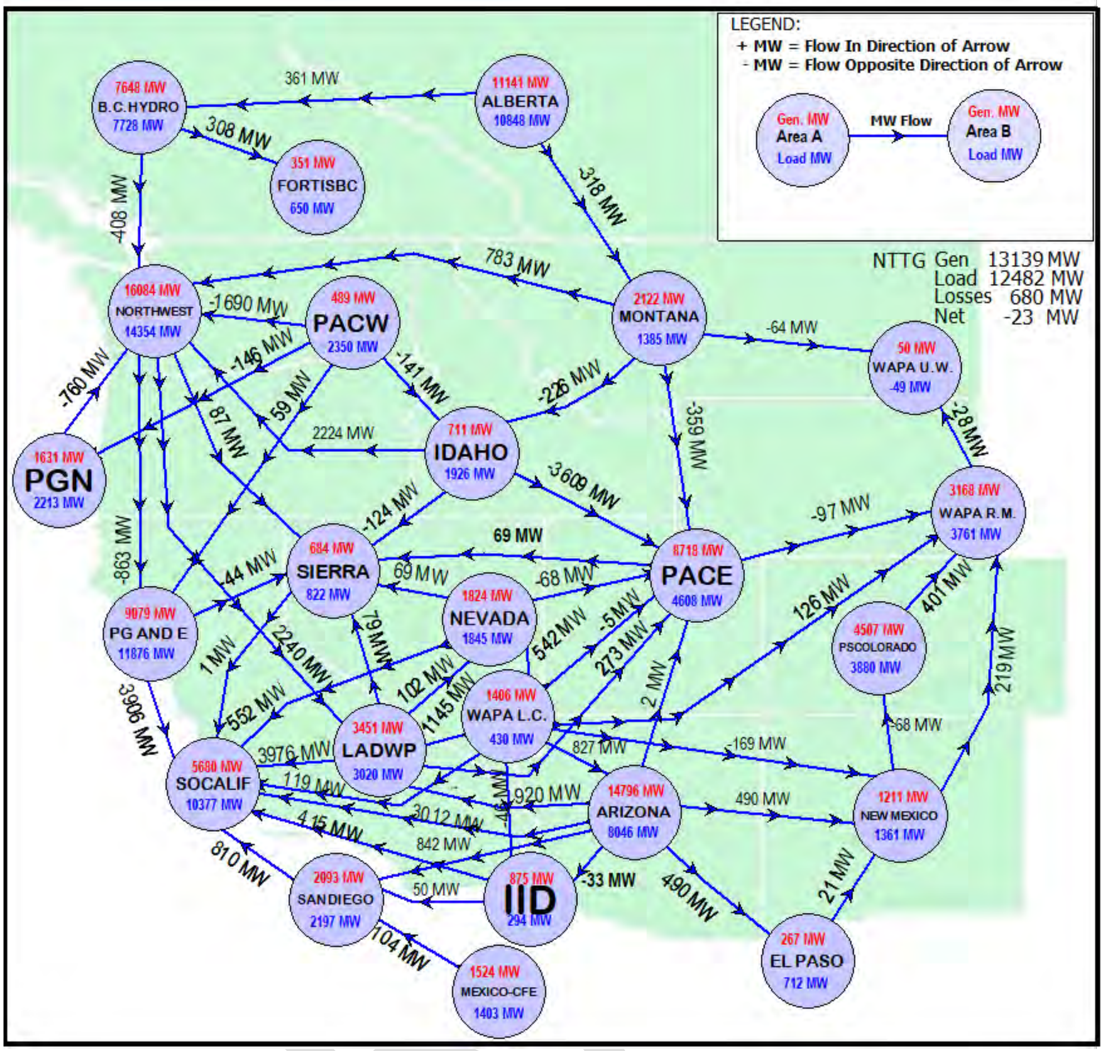


Figure 19 – Tie-line flows for High Borah West Case
(December 11, 2028 Hour 2 - NTTG Case Gv2)

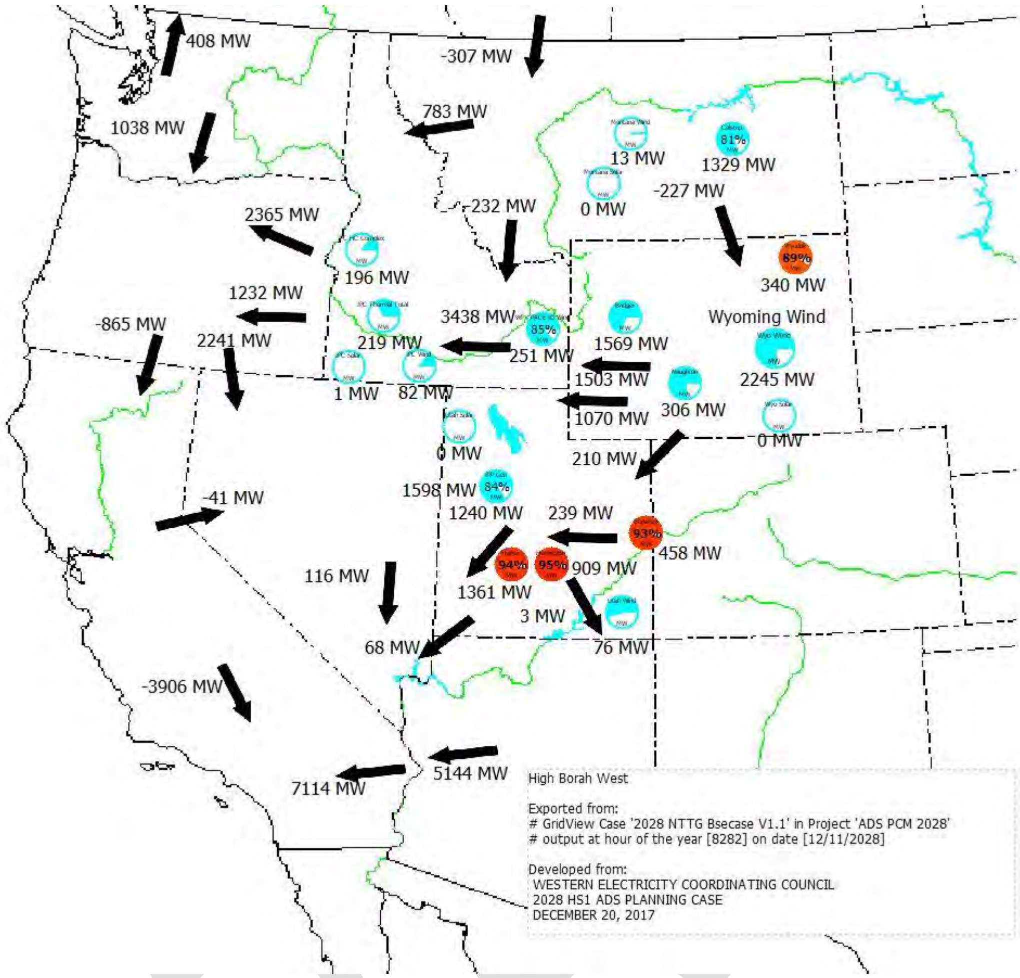


Figure 20 – Other flows for High Borah West Case
(December 11, 2028 Hour 2 - NTTG Case Gv2)

The wind level in this case, 2245 MW, is likely to be exceeded 2530 hours per year, see Section IIID.

H. High NTTG Footprint Import Case

The NTTG load and generation in this case are 20,872 MW and 15,135 MW respectively with a NTTG import of 6,267 MW. Currently there are no operating procedures which would restrict this operation in this dispatch region. This case was selected to test this condition for any concerns. One notable condition of this dispatch hour is that the Wyoming wind production was near zero MW. The bubble diagram follows.

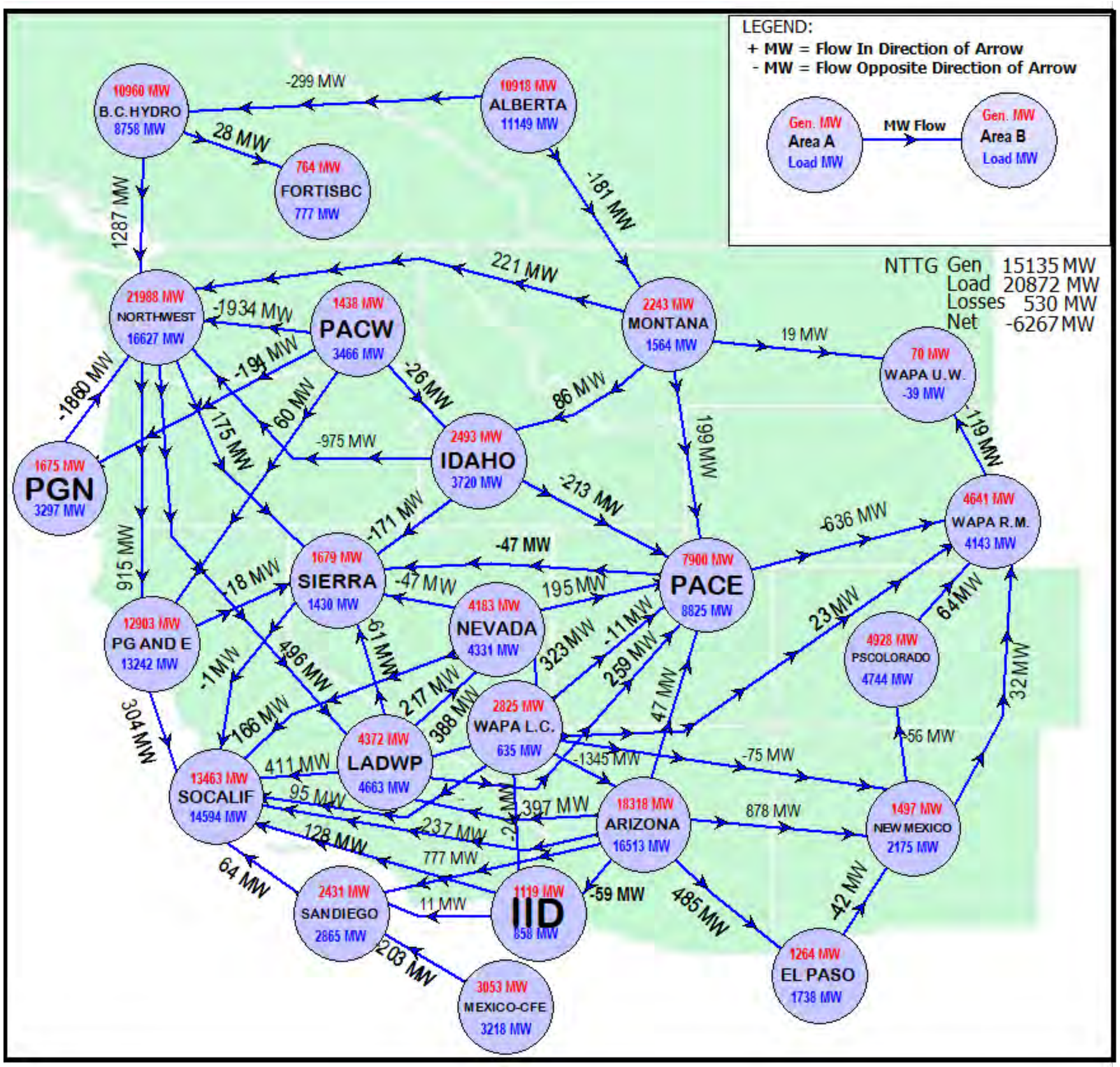


Figure 21 – Tie-line flows for High NTTG Footprint Import Wind Case
(July 27, 2028 Hour 14 - NTTG Case H)

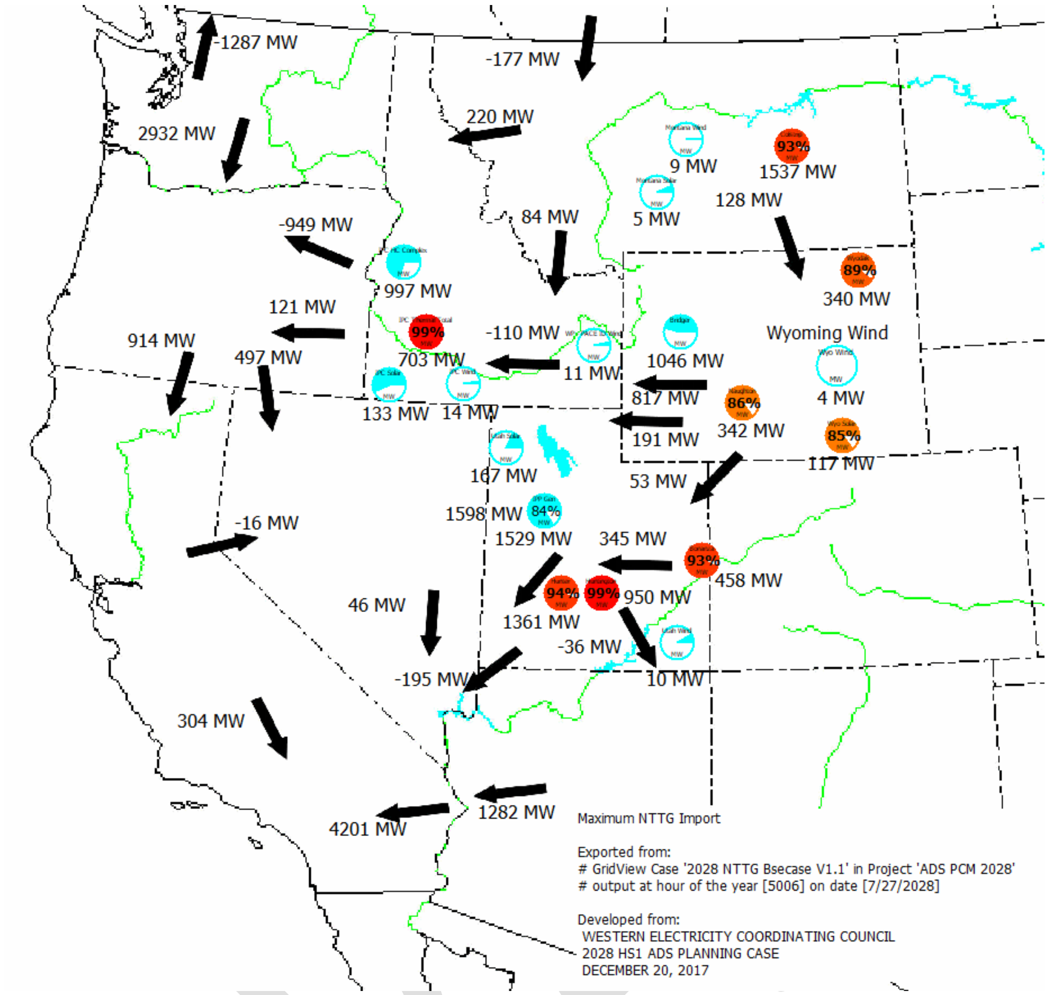


Figure 22 – Other flows for High NTTG Footprint Import Wind Case (July 27, 2028 Hour 14 - NTTG Case H)

I. High Aeolus West and South Case

The NTTG load and generation in this case are 14,287 MW and 13,317 MW respectively with a NTTG import of 1,624 MW. In reviewing the flows of the other extracted hours, it was noted that few hours fully stressed the Gateway South project. This hour was selected for that purpose. In this case, the Gateway South project is flowing 1,018 MW. The bubble diagram follows.

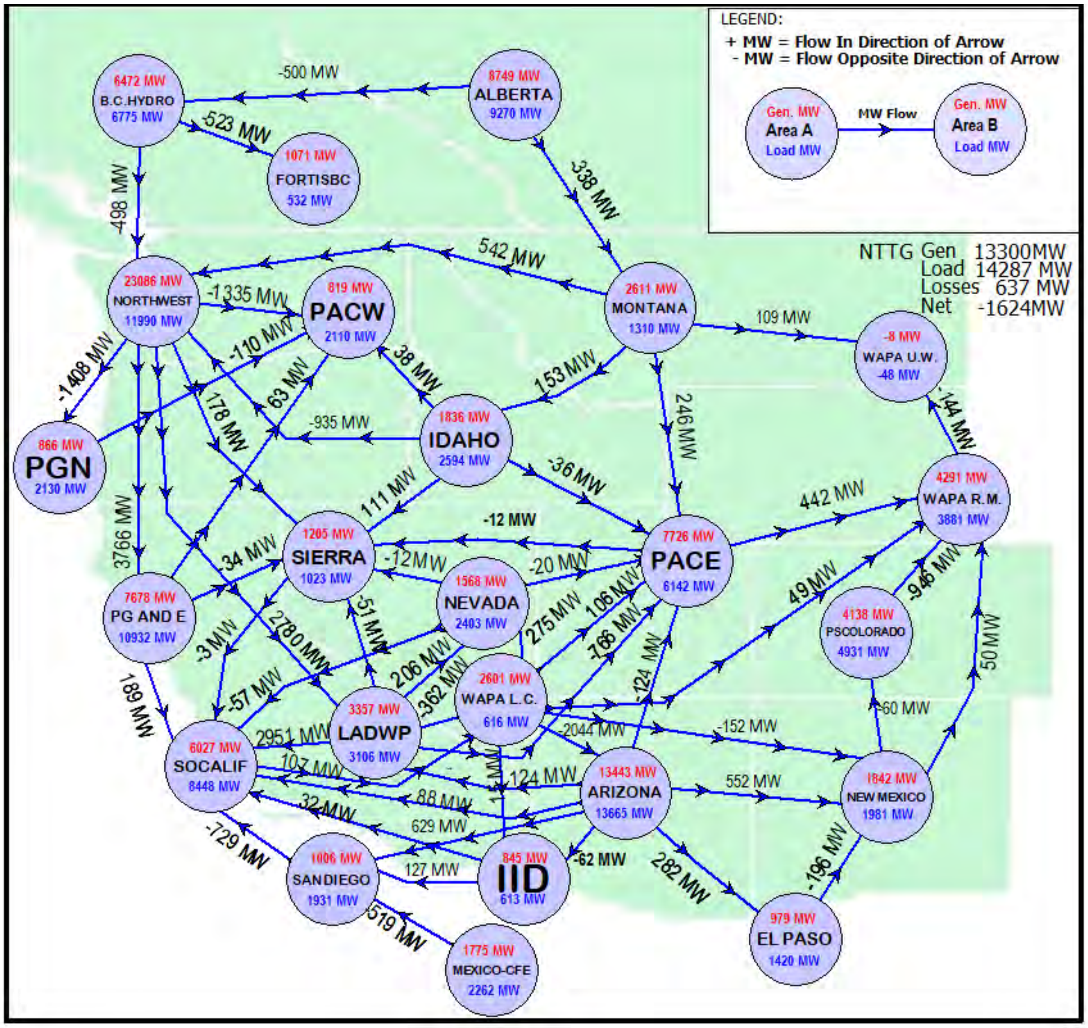


Figure 23 – Tie-line flows for High Aeolus West and South Case
(June 3, 2028 Hour 18 - NTTG Case I)

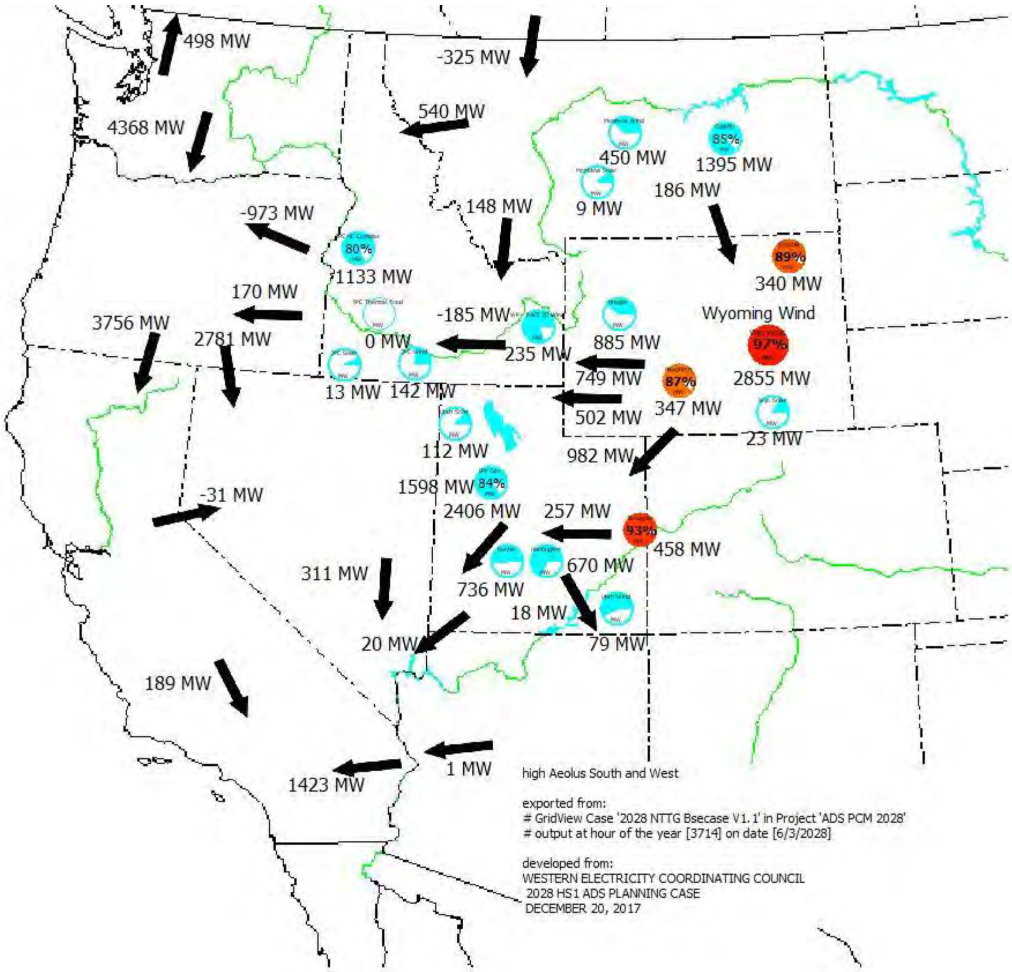


Figure 24 – Other flows for High Aeolus West and South Case (June 3, 2028 Hour 18 - NTTG Case I)

The wind level in this case, 2855 MW, is likely to be exceeded 513 hours per year, see Section IIID.

V. Change Case Results

For each of these stress conditioned cases, a "Null" Change Case was prepared, and reliability results were analyzed. The Null case represents roughly today's transmission topology with 2028 Loads and Resource requirements. For all null cases, the Antelope resource addition resulted in poor performance without the associated Antelope Projects.

Generally, cases can be ranked in increasing severity order: the Heavy Winter case (B), the high NTTG Import case (H), the Heavy Summer case (A); the high eastbound Idaho-Northwest case (C); the High Tot2 case (E); the high Borah West case (G), the High Wyoming wind case (F), and finally the Aeolus West and South case (I) being the worst.

The IRTP as submitted in Quarter one includes the following Non-Committed projects:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains a number of sub-sections:
    - Windstar-Aeolus 230 kV
    - Aeolus-Anticline (Jim Bridger) 500 kV
    - Anticline-Populus 500 kV
    - Populus-Borah 500 kV
    - Populus- Cedar Hill 500 kV
    - Cedar Hill-Hemingway 500 kV
    - Cedar Hill- Midpoint 500 kV
    - Borah-Midpoint 345 to 500 kV conversion
    - Midpoint-Hemingway #2 500 kV
- The Gateway South Project:
    - Aeolus-Clover 500 kV
- The Antelope Projects:
    - Goshen-Antelope 345 kV
    - Antelope-Borah 345 kV

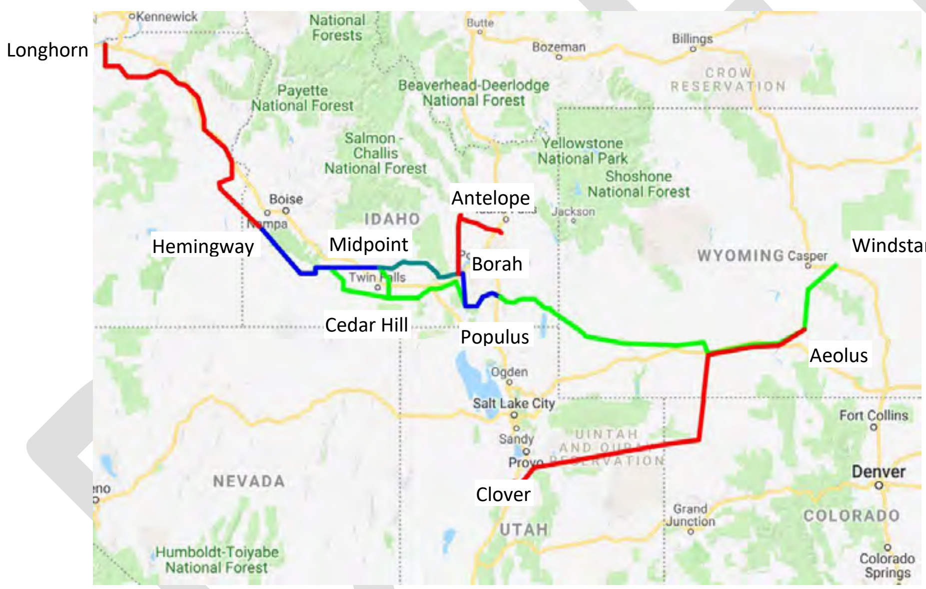


Figure 25 - IRTP Projects

The prior Regional Transmission Plan from last planning cycle included a subset of the projects submitted in the current Quarter one:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains several sub-sections:
    - Windstar-Aeolus 230 kV
    - Aeolus-Anticline (Jim Bridger) 500 kV
    - Anticline-Populus 500 kV
    - Populus- Cedar Hill 500 kV

- Cedar Hill-Hemingway 500 kV
- Borah-Midpoint 345 to 500 kV conversion

- The Gateway South Project:
  - Aeolus-Clover 500 kV
- The Antelope Projects:
  - Goshen-Antelope 345 kV
  - Antelope-Borah 345 kV

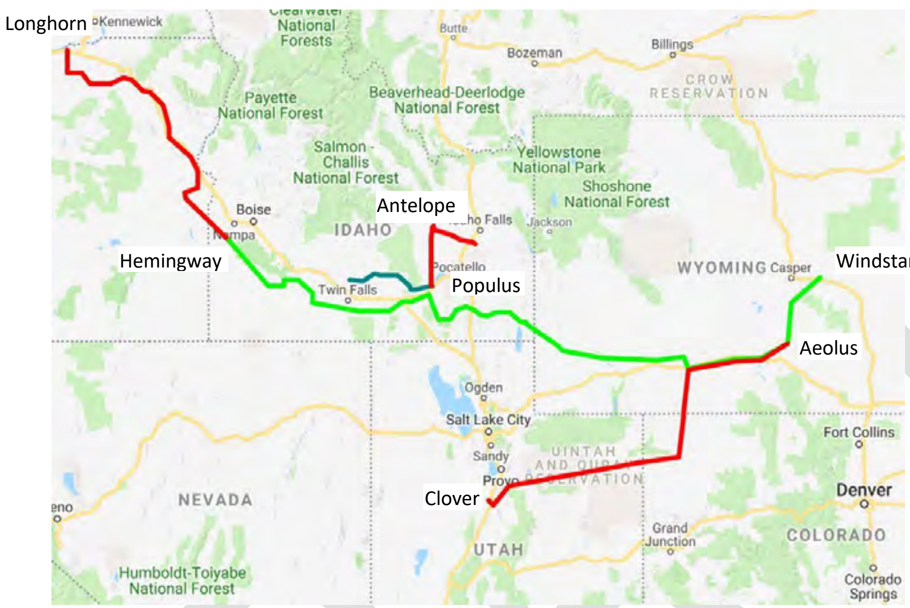


Figure 26 - pRTP Projects

To efficiently study the wide range of potential combinations of Non-Committed projects, the TWG formulated a Change Case matrix, an initial formulation of which was included in the Biennial Study Plan[29]. Once the stressed power flow cases had been selected and developed, the TWG modified the matrix to better reflect the recommended analysis. During the month of August 2018, stakeholder comments were solicited on the draft set of projects selected for analysis in the Change Case matrix. No comments were submitted. The matrix was also presented to the Planning Committee at the October and November meetings. Table 13 below, is the Change Case matrix that was used by the TWG:

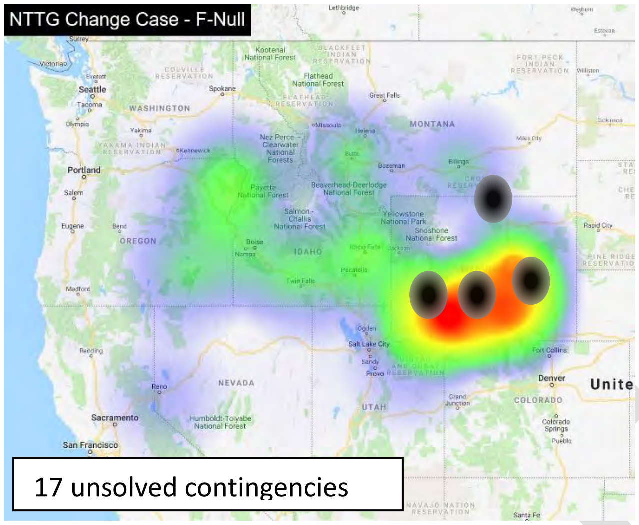
[29] The Biennial Study Plan is the study plan used to produce the Regional Transmission Plan, as approved by the NTTG Steering Committee.

Case	B2H	Gateway S	Gateway W	Antelope Projects	SWIP N	Cross-Tie	TWE DC	TWE DC/AC	Stressed Conditions:
null									A B C F G H I
pRTP	✓	✓	a	✓					A B C E F G H I
iRTP	✓	✓	✓	✓					A B C E F G H I
CC1	✓								A B C F G I
CC2		✓		✓					A C E F I
CC3		✓	a						A C E F I
CC4	✓		a	✓					A C E F I
CC5	✓	✓		✓					A C E F I
CC6	✓	✓	a						A B C E F G H I
CC7								✓	A B C E F I
CC8							✓		A B C E F I
CC9						✓			A B C F I
CC10					✓				A B C F
CC11				✓				✓	(E)+RPS@1500
CC12		✓		✓				✓	(E)+RPS@1500
CC13			a	✓				✓	(E)+RPS@1500
CC14		✓	a	✓				✓	(E I)+RPS@1500
CC15				✓			✓		(E)+RPS@1500
CC16		✓		✓			✓		(E)+RPS@1500
CC17			a	✓			✓		(E)+RPS@1500
CC18		✓	a	✓			✓		(E)+RPS@1500
CC19				✓		✓			(E)+RPS@1500
CC20		✓		✓		✓			(E)+RPS@1500
CC21		✓	a	✓		✓			(E I)+RPS@1500
CC22			a	✓	✓				(E)+RPS@1500
CC23		✓	a	✓	✓				(E I)+RPS@1500
CC24		✓	a	✓	✓	✓			(E I)+RPS@3000
CC25			a	✓	✓			✓	(E)+RPS@3000
CC26		✓		✓		✓		✓	(E)+RPS@3000
CC27		✓	a	✓	✓	✓		✓	(E)+RPS@4500
CC28			a	✓	✓		✓		(E)+RPS@3000
CC29		✓		✓		✓	✓		(E)+RPS@3000
CC30		✓	a	✓	✓	✓	✓		(E)+RPS@4500
CC31	✓	✓	b	✓					E F G I
CC32	✓	✓	c	✓					F G I
CC33	✓	✓	d	✓					E F I

	The change case does not include the non-Committed Project
✓	The change case includes the non-Committed Project
a	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah
b	pRTP less Populus-Cedar Hill-Hemingway
c	pRTP less Populus-Cedar Hill-Hemingway plus Populus-Borah
d	pRTP less Populus-Cedar Hill-Hemingway and Anticline-Populus
	The change case was run with and without B2H

Table 13 - Change Case matrix used in the development of this report

In all, over 150 reliability studies were performed with the previously mentioned 480+ contingencies. Appendix C lists selected path flows from a subset of the cases developed. A summary of the performance of these cases is described below. To better communicate the results of these studies, the TWG created heat maps which present a weighted[30] graphical performance of a Change Case on a specific flow condition. In these heat maps, performance issues were accumulated for each powerflow zone, for example, the F-Null case performance looks like:



Case: F-Null

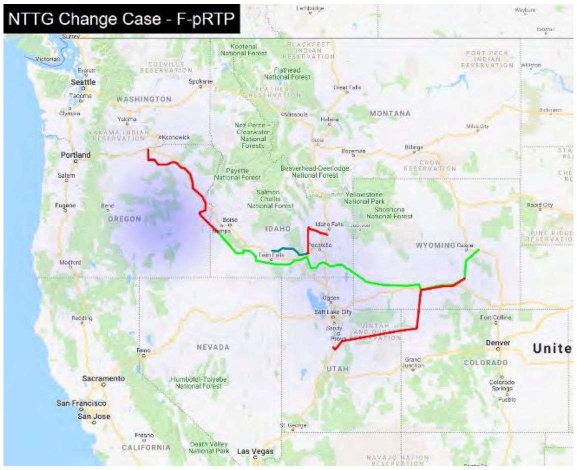
Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Imnaha_OR			1	5
Billings_MT			4	20
Butte_MT	4	15		34
Pac N of Path C			10	50
3 Mile Knoll_ID			3	15
Enterprise_OR			1	5
Harney_OR		9		18
Steamboat_NV			1	5
Upalco_UT			1	5
Point of Rocks_WY	36	4	97	529
Bridger_WY			5	25
Hanna_WY	4		24	124
Miners_WY			19	95
Casper_WY			42	210
Melba_ID	4		2	14
John Day_OR		1		2
Twin Falls_ID	2		5	27
Hells Canyon_ID-OR		2		4
	Times 1	Times 2	Times 5	

Figure 27 and Table 14 – Example Heat Map and Companion Table of the F-Null Case

This map does not indicate where the contingency occurred but the general location where the performance (e.g., overloaded transmission line) issues occurred for the contingency which may be hundreds of miles away. In the above heat diagram the accumulation of overloads and voltage issues are represented by the various colors. The map shows three general areas of reliability violations – NW Wyoming/SE Montana, southern Idaho and SE Washington/Central Oregon. These violations are occurring because the transmission systems are incapable of handling anticipated transfers across that area's transmission system.

The same map for the F-pRTP case looks like:

[30] High voltage conditions had a weighting of 1; Low voltage conditions had a weighting of 2; and overloads of branches had a weighting of 5. For example, a zone in which 10 contingencies caused an overload of one branch in that zone would receive a total weight of 50 (i.e., 10 x 5), which would then be translated into a color on the map. A blue color represents a weighted total of about 10, green is a count up to 30, yellow is a count up to 50 and red is for a weighted count exceeding about 70. In a number of studies, there were many contingencies that were unable to be solved indicating that that particular portion of the system was stressed well beyond its capabilities for reliable operation. In those cases, black circles have been added to the figures to indicate the approximate location of violations that would have occurred had the case stress reduced to permit a solution.



Case: F-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Burns_OR			1	5
	Times 1	Times 2	Times 5	

Figure 28 and Table 15 – Heat Map and Companion Table of the F Case with the pRTP facilities included

In this case, the map points to an overload in Oregon area on the Burns Series capacitor that is likely to be replaced prior to 2028. The rating of the bank will be re-evaluated to avoid it becoming a bottleneck to system performance. This map shows the dramatic improvement of the pRTP Change Case when compared to the Null case.

A. Heavy Summer Case results

In the Heavy Summer Null case, the most significant issue is related to the integration of the new Antelope Project resources. The remaining issues in the pRTP case shown in Figure 30 are local load service issues that are expected in a 1 in 5 peak load scenario.

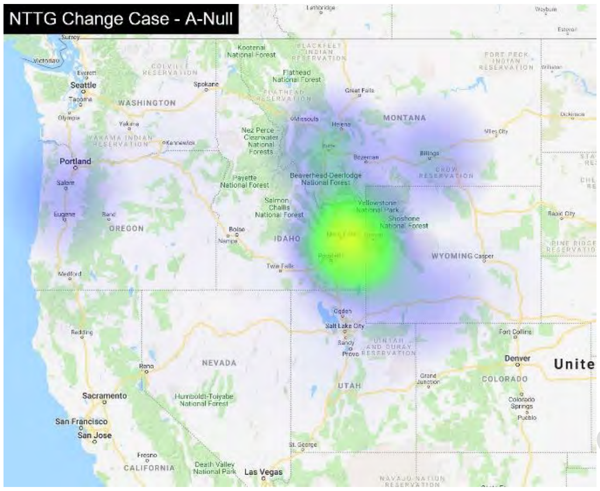


Figure 29

Case: A-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Billings_MT			2	10
Butte_MT			4	20
Pac BPA Loads_ID		1	1	7
Pac N of Path C			15	75
Soda Springs_ID		2		4
Salem_OR			1	5
Point of Rocks_WY			1	5
	Times 1	Times 2	Times 5	

Table 16

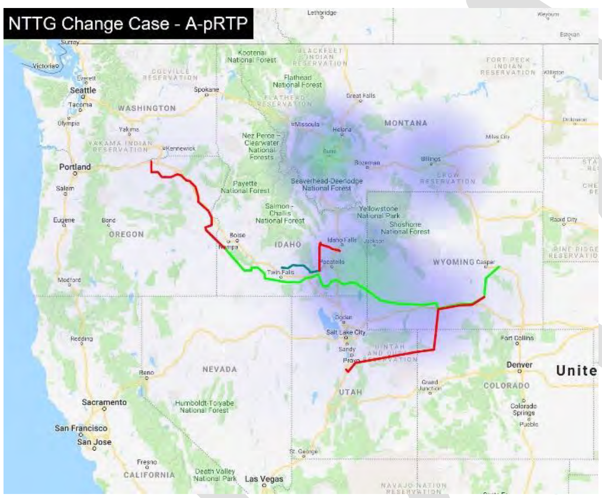


Figure 30

Case: A-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Billings_MT			2	10
Butte_MT			4	20
Pac BPA Loads_ID		1		2
Soda Springs_ID		2		4
Point of Rocks_WY			1	5
	Times 1	Times 2	Times 5	

Table 17

B. Heavy Winter Case results

In the Heavy Winter Null case, similar to the Heavy Summer Null case, the most significant issue is related to the integration of the new Antelope Project resources. The remaining issues in the pRTP case shown in Figure 32 are very slight overload near Billings and an N-2 overload issue at Bridger.

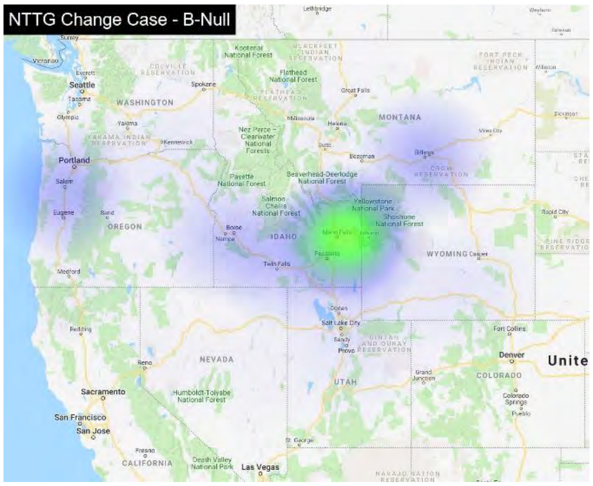


Figure 31

Case: B-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Billings_MT			1	5
Pac BPA Loads_ID			1	5
Pac N of Path C			7	35
Salem_OR			1	5
Melba_ID	1			1
Twin Falls_ID	1			1
	Times 1	Times 2	Times 5	

Table 18

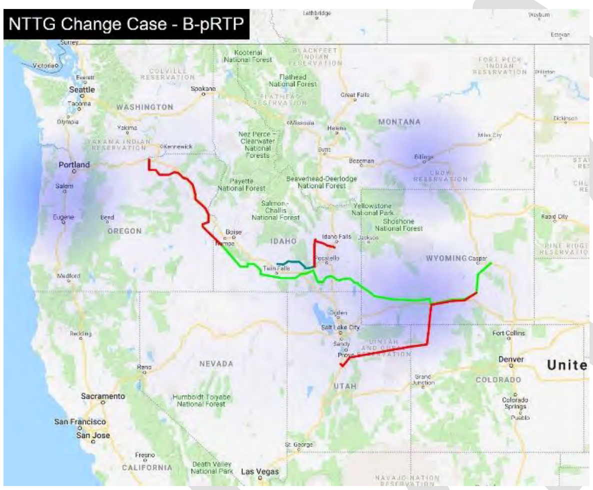


Figure 32

Case: B-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Billings_MT			1	5
Salem_OR			1	5
Point of Rocks_WY			1	5
	Times 1	Times 2	Times 5	

Table 19

C. High Eastbound Idaho-Northwest Case results

Similarly, comparing the High Import Null Case (C-Null) with a case where the B2H project (inserted as a red line in the right heat map) is added is shown below:

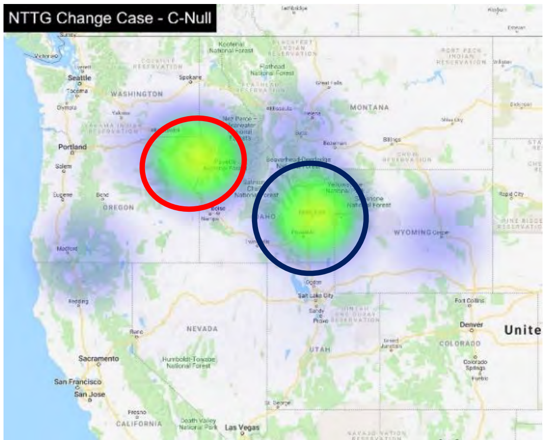


Figure 33

Case: C-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Imnaha_OR			8	40
Butte_MT		4		8
Pac BPA Loads_ID			1	5
Pac N of Path C			12	60
Roundup_OR			1	5
Klamath Falls_OR	2			2
Medford_OR	1			1
Casper_WY			1	5
Arco_ID			1	5
Hells Canyon_ID-OR			7	35
	Times 1	Times 2	Times 5	

Table 20

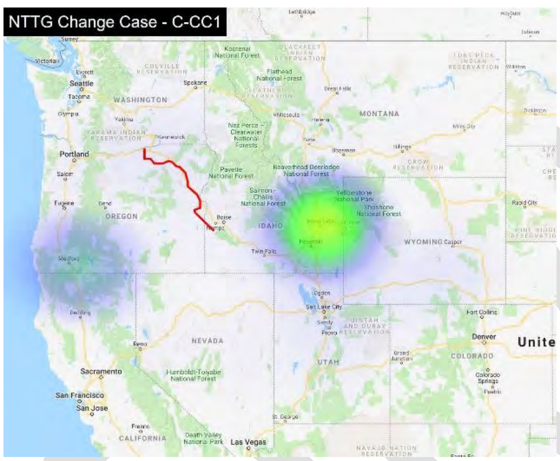


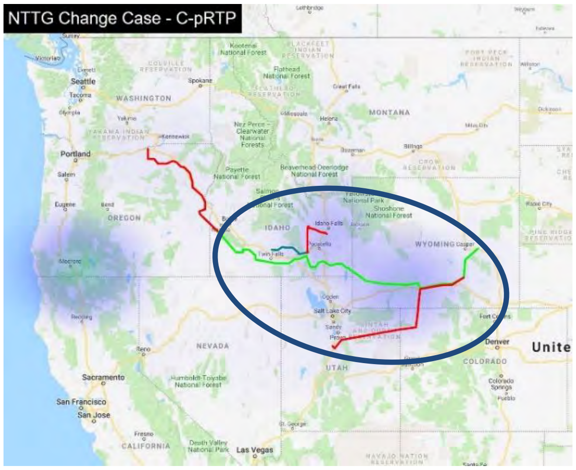
Figure 34

Case: C-CC1

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Pac BPA Loads_ID			1	5
Pac N of Path C			11	55
Grants Pass_OR	1			1
Klamath Falls_OR	2			2
Medford_OR	1			1
Arco_ID			1	5
	Times 1	Times 2	Times 5	

Table 21

The stress across the Idaho-Northwest path, shown within the red oval, has been relieved when B2H is added, as well as, stress across the Montana-Idaho path (WECC Path 18). The Antelope Resource is the cause of the violations shown in the blue oval. The heat map in Figure 34 indicates that the B2H project has little impact on the integration of the Antelope Resource. Including the other Non-Committed projects of the prior RTP in Figure 35 (transmission lines shown in the blue oval) with the B2H project, the violations for the C flow condition are eliminated.

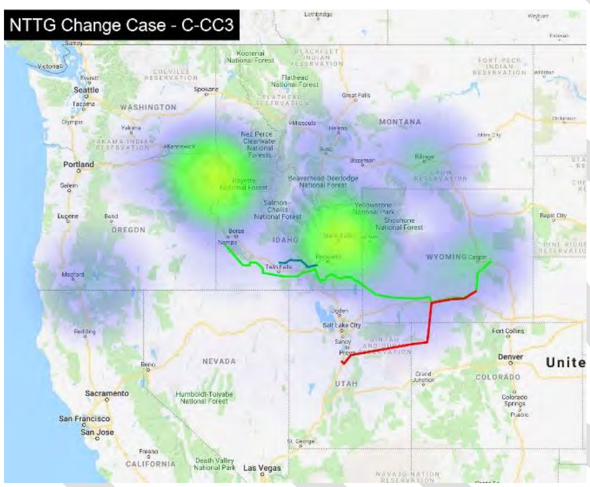


Case: C-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Pac N of Path C	1			1
Grants Pass_OR	1			1
Klamath Falls_OR	2			2
Medford_OR	1			1
Point of Rocks_WY			1	5
	Times 1	Times 2	Times 5	

Figure 35 **Table 22**

Change Case CC3, in the heat map Figure 36 below, tests to see if the Gateway West and/or Gateway South projects shown in the blue oval above can replace or be comparable to the B2H or the Antelope projects.



Case: C-CC3

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Imnaha_OR			6	30
Billings_MT			4	20
Butte_MT		4		8
Pac BPA Loads_ID			1	5
Pac N of Path C			10	50
Roundup_OR			1	5
Klamath Falls_OR	2			2
Medford_OR	1			1
Point of Rocks_WY			1	5
Casper_WY			4	20
Melba_ID	1			1
Arco_ID			1	5
Hells Canyon_ID-OR			6	30
	Times 1	Times 2	Times 5	

Figure 36 **Table 23**

D. High Westbound Idaho-Northwest case results

The flow pattern extracted for this case did not meet the objectives for this case, so further study of the case was dropped.

E. High Tot2/COI/PDCI Case results

The E-Null case results depicted in Figure 37 are similar to the Fv2 case in Wyoming. The stress elsewhere in the NTTG footprint appears to less. The remaining issues shown in Figure 38, the E-pRTP case, are local overloads in the Bonneville Dam area and N-2 transformer overload at the Jim Bridger Power Plant.

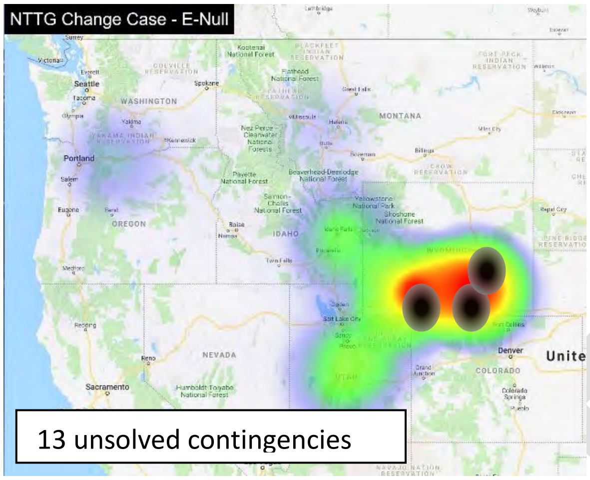


Figure 37

Case: E-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Pac N of Path C			6	30
Soda Springs_ID			1	5
The Dalles_OR			2	10
Mona_UT			1	5
Sigurd_UT		8	2	26
Upalco_UT			1	5
Carrbonville_UT			1	5
Garrison_MT	1			1
Point of Rocks_WY	13	19	58	341
Bridger_WY			2	10
Hanna_WY	5	188	28	521
Miners_WY			6	30
Medicine Bow_WY			1	5
Rock River_WY	2	14	1	35
	Times 1	Times 2	Times 5	

Table 24

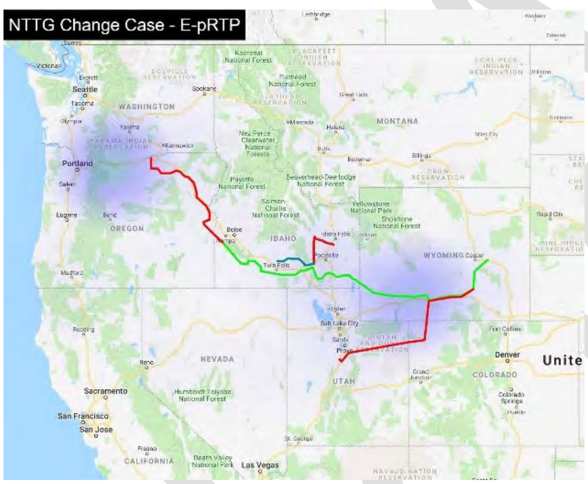


Figure 38

Case: E-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
The Dalles_OR			2	10
Point of Rocks_WY			1	5
	Times 1	Times 2	Times 5	

Table 25

Without Gateway South in E-CC4, that configuration performs poorly. Similarly, without Gateway West in E-CC5, that configuration has similar issues.

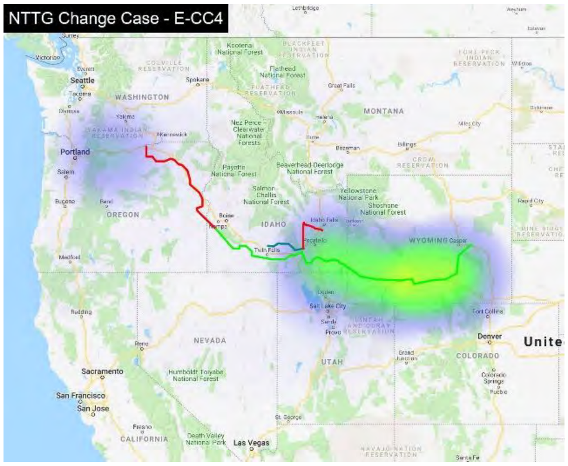


Figure 39

Case: E-CC4

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Soda Springs_ID			3	15
The Dalles_OR			2	10
Logan_UT			1	5
Point of Rocks_WY		24	11	103
Hanna_WY		4	2	18
Miners_WY			2	10
	Times 1	Times 2	Times 5	

Table 26

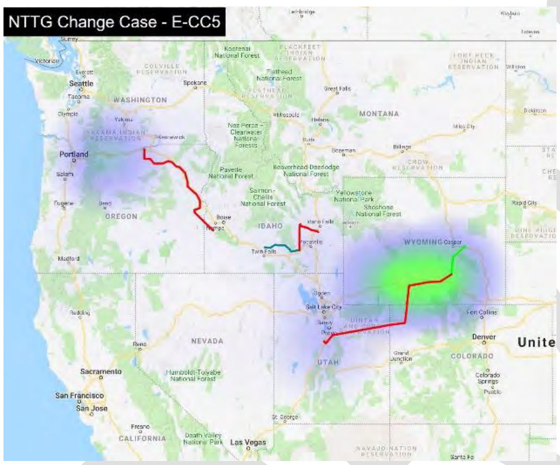


Figure 40

Case: E-CC5

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
The Dalles_OR			2	10
Mona_UT	1			1
Point of Rocks_WY		8	5	41
Hanna_WY		2	1	9
Miners_WY			1	5
	Times 1	Times 2	Times 5	

Table 27

F. High Wyoming Wind Case results

The F-Null case results depicted in Figure 41 with the wind production at the 2,707 MW level, indicate that its performance is worse than the heavy southern Idaho export case. When the pRTP facilities are added in Figure 42, the only remaining problems are with the rating of the Burns series capacitor bank. This bank is due for replacement since it has reached the end of its useful life. Its future rating has not been determined but the parties will consider these studies in establishing its new rating.

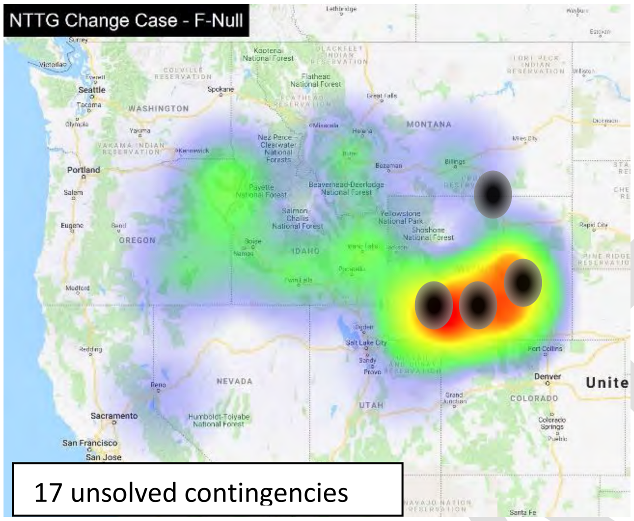


Figure 41

Case: F-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Imnaha_OR			1	5
Billings_MT			4	20
Butte_MT	4	15		34
Pac N of Path C			10	50
3 Mile Knoll_ID			3	15
Enterprise_OR			1	5
Harney_OR		9		18
Steamboat_NV			1	5
Upalco_UT			1	5
Point of Rocks_WY	36	4	97	529
Bridger_WY			5	25
Hanna_WY	4		24	124
Miners_WY			19	95
Casper_WY			42	210
Melba_ID	4		2	14
John Day_OR		1		2
Twin Falls_ID	2		5	27
Hells Canyon_ID-OR		2		4
	Times 1	Times 2	Times 5	

Table 28

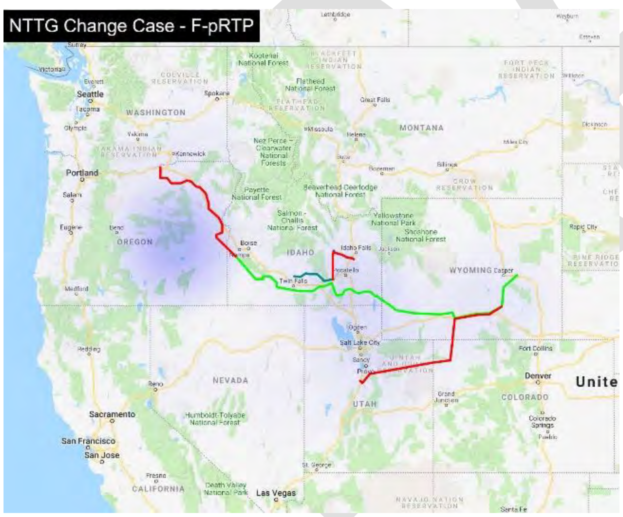


Figure 42

Case: F-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Burns_OR			1	5
	Times 1	Times 2	Times 5	

Table 29

The 2707 MW wind level represents a condition where over 1020 or 11.6% of the hours exceeded this level. The original target level of 2655 MW was 90% of the peak generated energy.

G. High Borah West Case results

The G-Null case results depicted in Figure 43 are similar to the E and F cases in Wyoming.

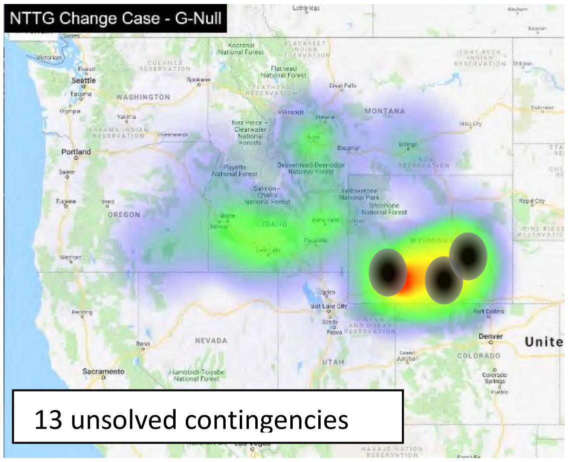


Figure 43

Case: G-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overload	Total
Billings_MT			4	20
Butte_MT	4	19		42
Pac N of Path C		3	7	41
Harney_OR		8		16
Point of Rocks_WY	25		63	340
Hanna_WY	11		10	61
Miners_WY			10	50
Casper_WY			6	30
Melba_ID	2			2
Twin Falls_ID	1		7	36
Mountain Home_ID			2	10
Hells Canyon_ID-OR		2		4
	Times 1	Times 2	Times 5	

Table 30

Figure 44

Case: G-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overload	Total
Davenport_WA			1	5
Burns_OR			1	5
	Times 1	Times 2	Times 5	

Table 31

The G-CC31 configuration shown in Figure 45 performs poorly without the Populus-Cedar Hill-Hemingway segment. Connecting Populus to Borah in G-CC32 helps slightly but the Populus-Cedar Hill-Hemingway segment is still needed at these transfer levels.

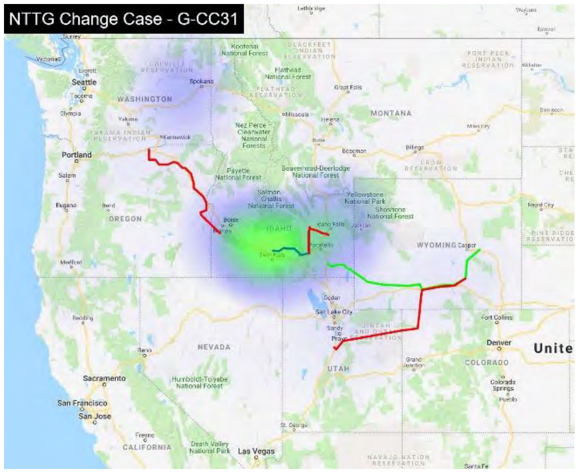


Figure 45

Case: G-CC31

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Davenport_WA			1	5
Pac N of Path C	1		2	11
Twin Falls_ID			8	40
Mountain Home_ID			2	10
	Times 1	Times 2	Times 5	

Table 32

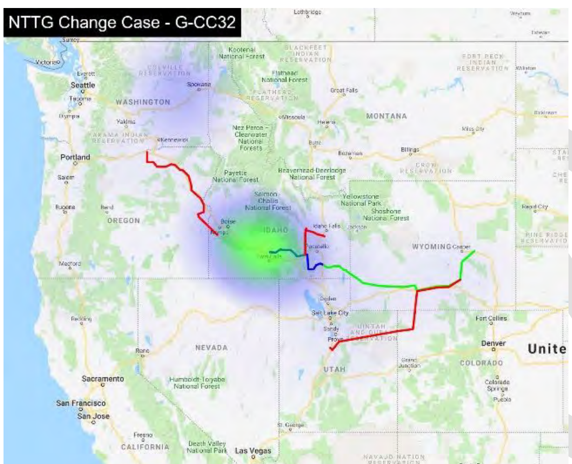


Figure 46

Case: G-CC32

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Davenport_WA			1	5
Twin Falls_ID			7	35
Mountain Home_ID			2	10
	Times 1	Times 2	Times 5	

Table 33

In the G case without NTTG footprint exports (Gv2) shown in Figure 47, the performance of the case in not significantly different than Figure 45. The Populus-Cedar Hill-Hemingway segment is needed to transfort power within the NTTG footprint and is not dependant on exporting energy outside NTTG.

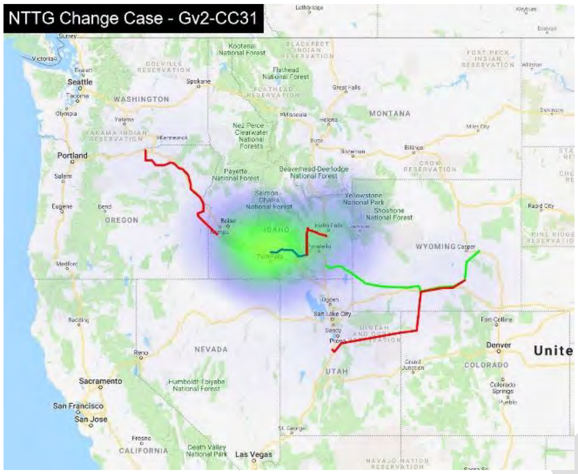


Figure 47

Case: Gv2-CC31

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Pac N of Path C	1		2	11
Twin Falls_ID			10	50
Mountain Home_ID			2	10
	Times 1	Times 2	Times 5	

Table 34

H. High NTTG Footprint Import results

In the High NTTG footprint import case, again the most significant issue is related to the integration of the new Antelope Project resources. The remaining issues in the pRTP case shown in Figure 49 are very slight overload near Vernal and low N-1 voltages in the Three Mile Knoll area.

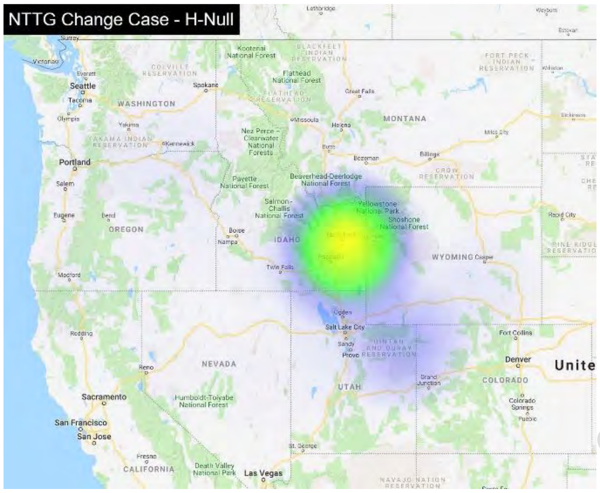


Figure 48

Case: H-Null

Zones	Count of High Voltage	Count of Low Voltage	Count of Overload:	Tota
Pac BPA Loads_ID			1	5
Pac N of Path C			20	100
Soda Springs_ID		2		4
Pocatello_ID			1	5
Vernal_UT			1	5
	Times 1	Times 2	Times 5	

Table 35

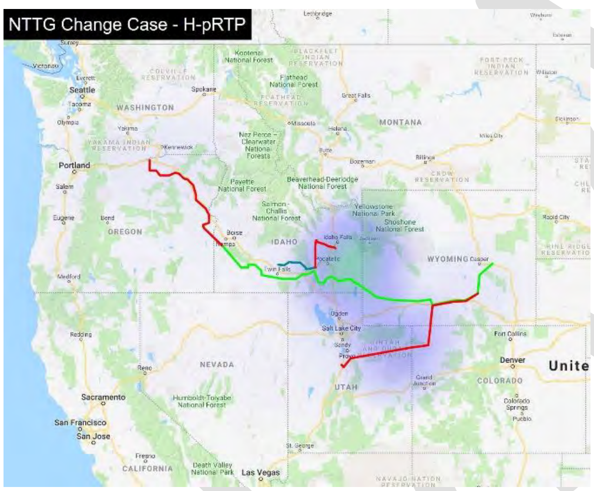


Figure 49

Case: H-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overload:	Tota
Pac BPA Loads_ID		1		2
Soda Springs_ID		2		4
Vernal_UT			1	5
	Times 1	Times 2	Times 5	

Table 36

I. High Aeolus West and South Case results

The I Null case could not be solved without some Wyoming transmission facility additions. The I Null+ (including those additions) case results are depicted in Figure 50.

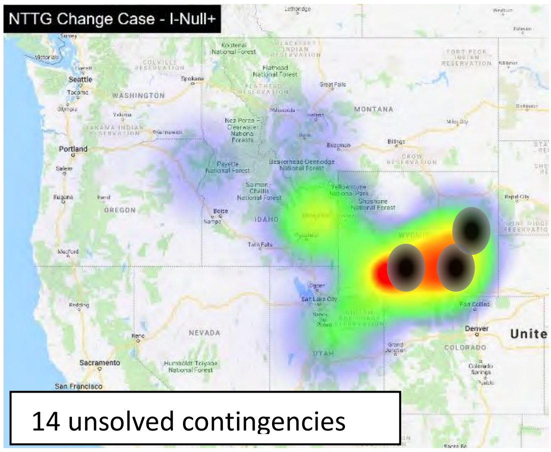


Figure 50

Case: I-Null+

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Butte_MT		4		8
Pac BPA Loads_ID			1	5
Pac N of Path C		1	14	72
Mona_UT			1	5
Upalco_UT			1	5
Carrbonville_UT			1	5
Point of Rocks_WY	34	11	111	611
Hanna_WY	7		35	182
Miners_WY			20	100
Glenrock_WY			20	100
Casper_WY	2			2
Arco_ID			1	5
Hells Canyon_ID-OR			2	10
	Times 1	Times 2	Times 5	

Table 37

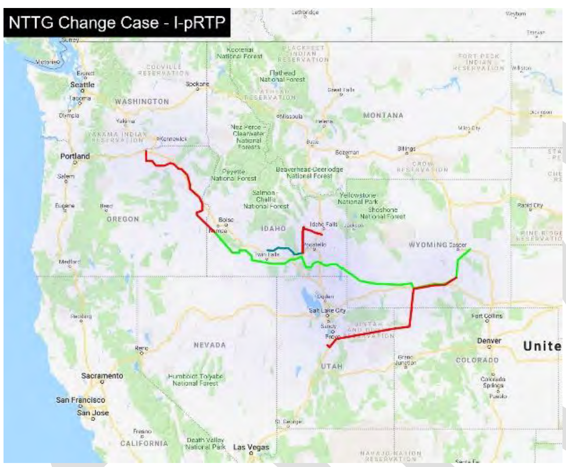


Figure 51

Case: I-pRTP

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
	Times 1	Times 2	Times 5	

Table 38

Case I-CC4 and I-CC5 check to see if either Gateway project, West or South, can perform adequately without the other. Both cases have an unsolved contingency indicating the both configurations are well beyond their capability at this stress level.

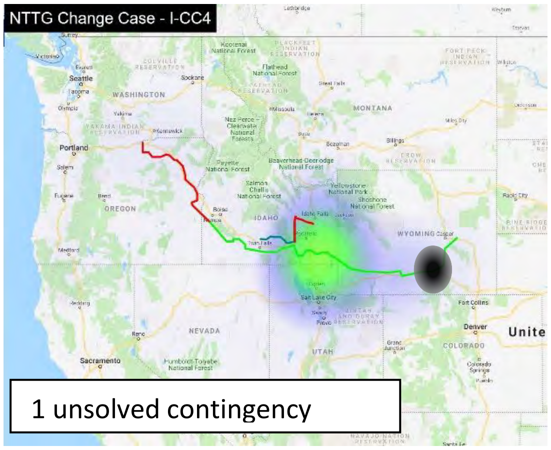


Figure 52

Case: I-CC4

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
Pac N of Path C	1			1
Soda Springs_ID			2	10
Logan_UT			1	5
North Logan_UT			1	5
Point of Rocks_WY	1			1
	Times 1	Times 2	Times 5	

Table 39

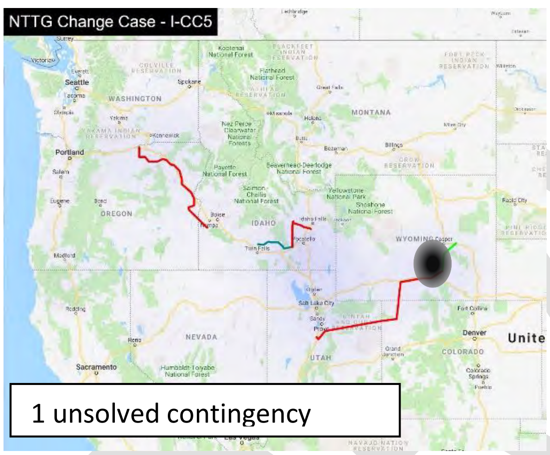


Figure 53

Case: I-CC5

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
	Times 1	Times 2	Times 5	

Table 40

In the case of CC4 (Figure 52, Gateway West without Gateway South) and CC5 (Figure 53, Gateway South without Gateway West), perform poorly for loss of either Gateway segments.

Figure 54

Case: I-CC33

Zones	Count of High Voltage	Count of Low Voltage	Count of Overloads	Total
	Times 1	Times 2	Times 5	

Table 41

In Case I-CC33 (Figure 54), the western portions of Gateway West (west of Bridger) were excluded and replaced with the Gateway South project. This case performs satisfactorily, however, the Bridger dispatch level (885 MW) is low.

J. 2029 Bridger Retirement Sensitivity

Sensitivity cases were performed on the exported hours where all four Bridger Units were dispatched above 1500 MW (3 Unit operation). This occurred in the Heavy Summer case (Case A), the Heavy Winter case (Case B), the Idaho-Northwest Export case (Case D, not studied), the TOT2/COI/PDCI case (Case E) and the High Wyoming Wind case (Case F). In the other cases (Cases C, G, H and I), the Bridger dispatch was below 1500 MW and those conditions would not be impacted by a Bridger Unit Retirement.

Case A, B, E and F were adjusted to remove Bridger Unit 1 from service. In the Heavy Summer and Heavy Winter conditions (Cases A and B), the unit output was replaced by additional Coulee dispatch, as the Idaho and PacifiCorp non-renewable resources were already fully committed. For Cases E and F, the Idaho and PacifiCorp East control areas resources were adjusted on an ownership basis (2/3 PacifiCorp (east), 1/3 Idaho Power). In all four cases, the phase shifter between the 345 kV system and the 500 kV system at Bridger was adjusted to cause an increased 400 MW of flow from the 500 kV to the 345 kV systems, unloading the 500 kV system.

For Cases A and B there was no appreciable change in outage performance, since the Wyoming Wind transfers out of the state were relatively light. In Case E, a slight reduction in a Bridger N-2 Transformer outage overload occurred, yet the reduction would not change the need for mitigation. Similar to Case E, the Case F change in performance was minimal.

K. Interregional Transmission Projects

The Interregional Transmission Projects were analyzed to determine whether an ITP alone or in combination with the other ITPs and/or the Non-Committed projects could, from a regional perspective, satisfy NTTG's transmission needs on a regional or interregional basis more efficiently or cost effectively than through local planning processes. The ITPs were added to the Null cases without any additional resources to serve NTTG load beyond those resources identified in the Quarter one data submittals. The ITP projects were tested with Cases A, B, C, E, F, and I. The high Wyoming wind case results are shown graphically below in Figure 55 through Figure 59.

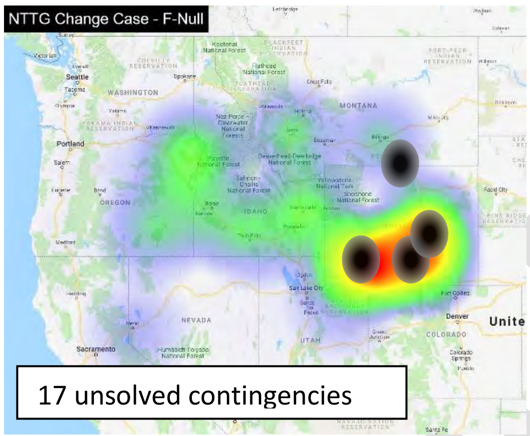


Figure 55

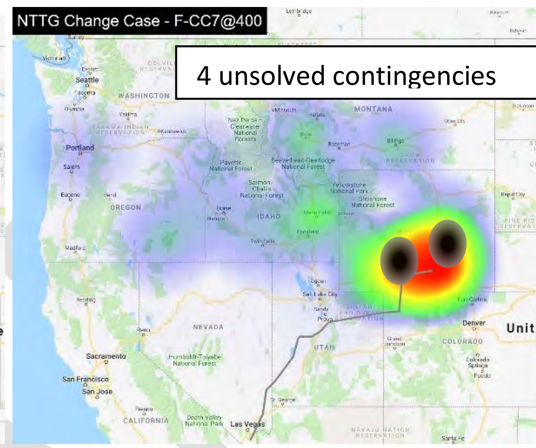
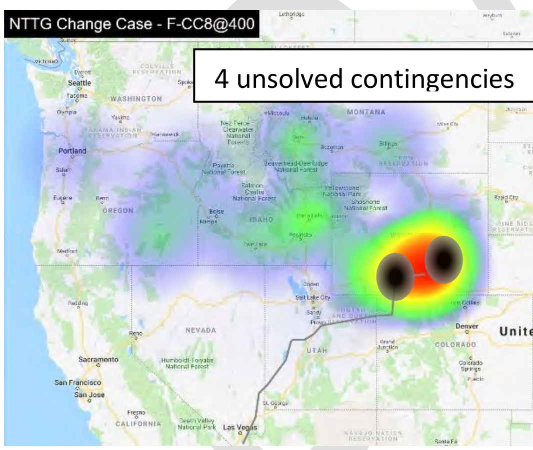


Figure 56



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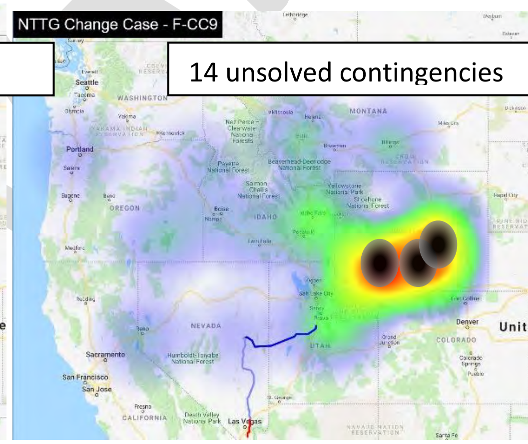


Figure 58

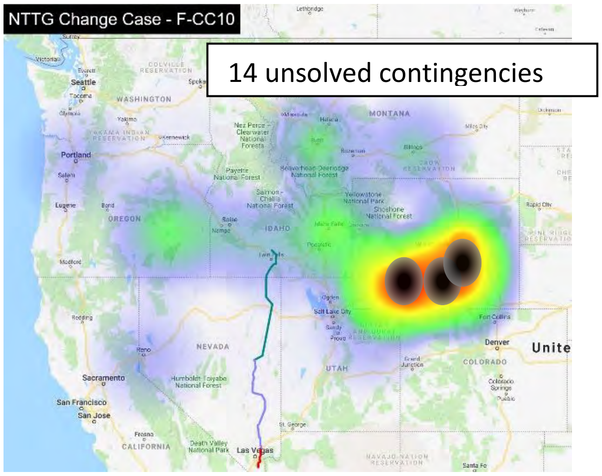


Figure 59

For the High Aeolus West and South case:

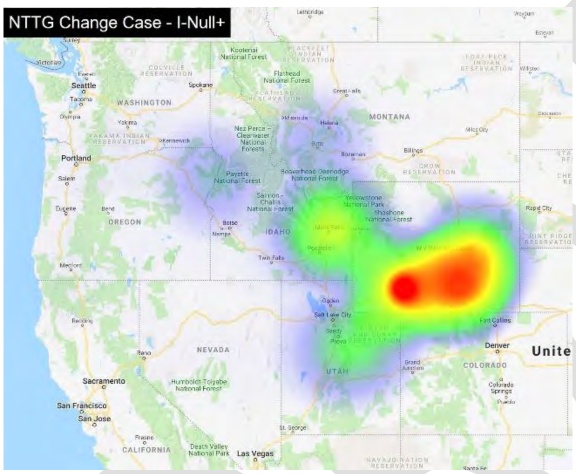


Figure 60

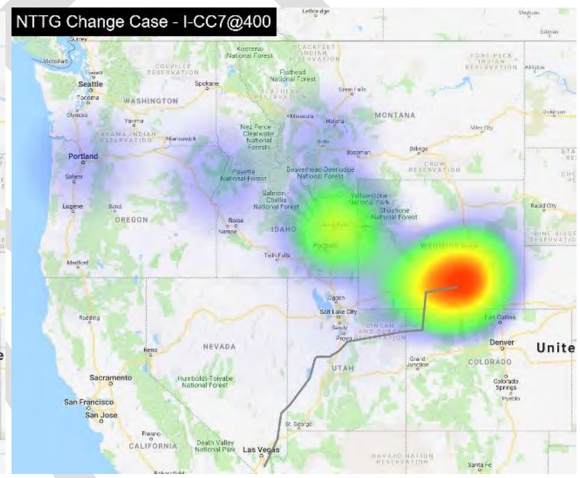


Figure 61

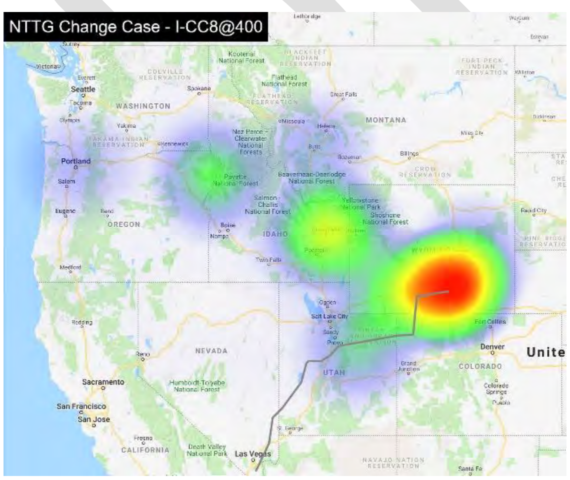


Figure 62

Note that, similar to the I-Null case, the CC9 and CC10 cases were not able to be solved without additional reinforcements in Wyoming. The ITPs do not provide the NTTG footprint with regional benefits by significantly reducing performance issues or displacing NTTG Non-Committed projects.

The dRTP was also analyzed to determine whether it is capable of supporting the interregional resource transfers proposed by the ITPs:

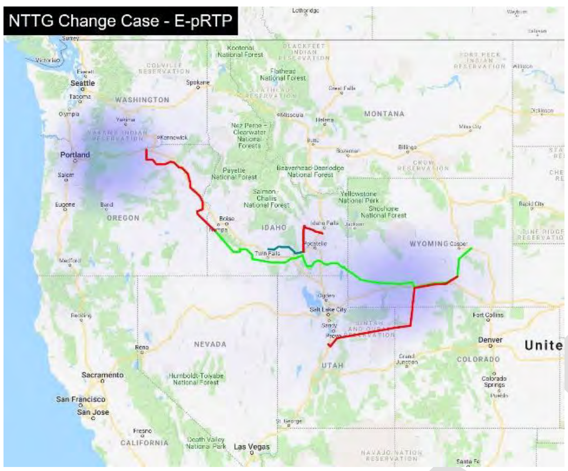


Figure 63

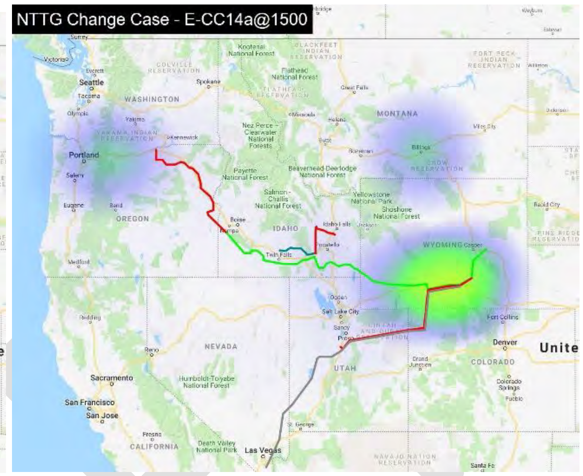


Figure 64

Figure 65

Figure 66

Each of the ITPs interfaces differently with the additional wind resources in Wyoming. In the TWE E-CC14a case (Figure 64), the case was run not tripping the wind resource for DC line outages. In order to avoid performance issues, the most of the 1,500 MW of resources would need to be tripped. Additionally, in these studies, the DC terminal was modeled by connecting the DC terminal to the existing 230 kV system, even when the Gateway West and South 500 kV projects were modeled in the case. Adding a 500 kV interface to the DC terminal would likely improve the Wyoming performance issue. Combinations of the ITPs projects were also studied with resource additions up to 4,500 MW.

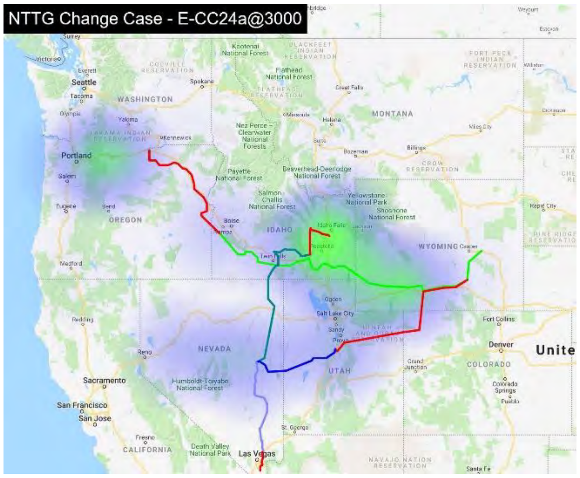


Figure 67

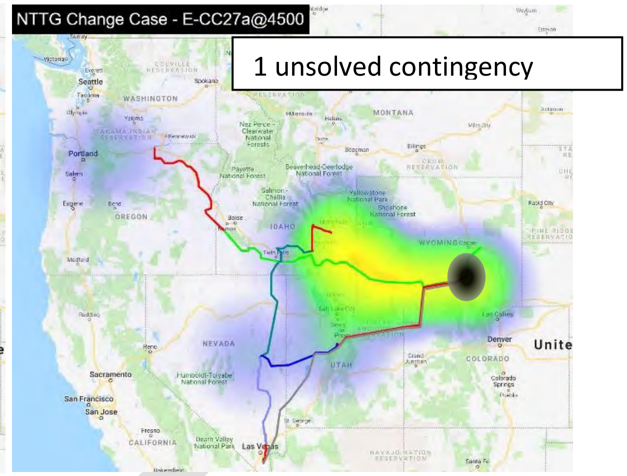


Figure 68

Again, Change Case E-CC27a in Figure 67 has the same issue as Change Case E-CC14a in Figure 64. Given the relatively long distances of the ITPs, the local integration performance issues in Wyoming are solvable.

VI. Impacts on Neighboring Regions

The TWG monitored the impacts of projects under consideration for the Draft Regional Transmission Plan on neighboring Planning Regions through each Change Case. The TWG found that the IRTP or the alternative Change Case plans did not impact neighboring Planning Regions.

VII. Reliability Conclusions

Based on the above study results, the TWG concludes that Change Cases pRTP and the IRTP satisfy the NTTG reliability criteria. The NTTG area is not reliably served in the year 2028 without including the following Non-Committed regional projects:

- Longhorn to Hemingway (formerly B2H)
- The Energy Gateway projects including segments:
  - Windstar-Aeolus 230 kV
  - Aeolus-Clover 500 kV
  - Aeolus-Anticline 500 kV
  - Anticline-Populus 500 kV
  - Populus-Cedar Hill-Hemingway 500 kV
  - Borah-Midpoint 345 kV to 500 kV conversion
- Antelope Transmission Project including:
  - Antelope – Borah 345 kV
  - Antelope – Goshen 345 kV
  - Antelope 345/230 kV transformers and interconnection facilities

The ITPs were evaluated to determine whether one or more ITP would defer or replace NTTG's Non-Committed projects. It was determined that none of the ITPs solve NTTG's reliability performance issues and, as such, have not been included in the NTTG dRTP.

VIII. Economic Evaluations

To determine which of the transmission plans (i.e., iRTP or pRTP) described above is the more cost effective, the calculation and evaluation of certain economic metrics is required. These transmission plans, incorporate some or all of the Non-Committed projects and Alternative Projects as may be necessary to satisfy NTTG's reliability performance criteria. Therefore, after determining the transmission plan that is more "efficient or cost effective" the Non-Committed projects of that plan will be included in the dRTP. From the Biennial Study Plan, the economic metrics to be evaluated are the capital related costs, NTTG footprint losses, and reserves. The economic evaluations are discussed below.

A. Capital Related Cost Metric

Development of the capital related cost metric required two steps to complete. The first step was to validate the Project Sponsor's Q1 submitted project capital cost. The validation was completed by comparing the Project Sponsor's submitted capital cost to the output results of a WECC Transmission Capital Cost Calculator, an MS Excel spreadsheet. If the submitted capital costs varied from the Calculator output by 20% or more, the TWG worked with the Project Sponsor to resolve the cost difference. If the difference could not be resolved, the TWG determined the appropriate cost to apply in the study process. If the Project Sponsor did not submit project capital cost, then the TWG developed the project's capital cost using the Transmission Capital Cost Calculator output. The analysis results from this first step are shown in Table 42.

Project Capital Cost Estimate
2018$

	Non-Committed Projects				
Range	B2H	GW South	GW West iRTP	Alt Proj GW West pRTP	
80%	$1,128,277,367	$1,282,740,293	$2,910,441,363	$2,337,522,943	
WECC Calculator	$1,410,346,708	$1,603,425,366	$3,638,051,703	$2,921,903,678	
120%	$1,692,416,050	$1,924,110,439	$4,365,662,044	$3,506,284,414	
Sponsor Estimate	$1,183,092,750	Not Provided	Not Provided	Not Provided	
Capital Cost Used	$1,183,092,750	$1,603,425,366	$3,638,051,703	$2,921,903,678	
					Plan Capital Cost
iRTP	$1,183,092,750	$1,603,425,366	$3,638,051,703		$6,424,569,819
pRTP	$1,183,092,750	$1,603,425,366		$2,921,903,678	$5,708,421,794
pRTP less iRTP					-$716,148,025

Table 42 Validated Cost Estimates

The second step is to develop the levelized capital related cost metric using the capital cost results described above. First, the annual capital related cost was computed for a 40 year revenue requirement time period using a WECC Capital Cost Calculator. The annual capital related cost is the sum of annual return, depreciation, taxes other than income, operation and maintenance expense, and income taxes (assumed 21%). A future escalation rate of 2.3% was applied to escalate and de-escalate costs from 2018 to the in-service year and a weighted cost of capital of 8.5% was estimated for all projects assuming 50% debt (@6%) and 50% equity (@11%) structure. The depreciation period was assumed to be 40 years for all projects. Next, the total present value of annual capital related costs was computed using a discount rate of 8.5% for all projects. Next the levelized[31] net present value annual capital related costs for the iRTP and the pRTP plans were computed. Table 43 provides that levelized capital related cost for the iRTP and the pRTP.

Plan Capital Related Cost ("CRC") Metric
11/16/2018

2018$	B2H	GW South	GW West iRTP	GW West pRTP	Plan CRC
In-Service Year	2026	2024	2024	2024	
Project Capital Cost	$1,183,092,750	$1,603,425,366	$3,638,051,703	$2,921,903,678	
NPV CRC	$1,882,583,955	$2,551,433,830	$5,789,011,693	$4,649,448,644	
Annual* CRC	$166,386,546	$225,500,839	$511,644,464	$410,927,596	
iRTP Lvl CRC	**$166,386,546**	**$225,500,839**	**$511,644,464**		**$903,531,849**
pRTP Lvl CRC	**$166,386,546**	**$225,500,839**		**$410,927,596**	**$802,814,981**
pRTP less iRTP					($100,716,868)
* Levelized Payment over 40 Yr Economic Life and 8.5% Discount Rate					

Table 43 Estimated Capital Related Cost Estimates

B. Energy Loss Metric

1. Background and Method

The Energy Loss Metric is used to capture the change in energy generated, based on system topology, to serve a given amount of customer load. The study year was 2028. Using Production Cost Modeling software, the NTTG footprint Balancing Authority Area ("BAA") annual MWh losses for the iRTP and pRTP were calculated based on hourly load, generation and export\import flows on external tile lines. A reduction in annual energy losses represents a benefit because less energy is required to serve the same load. The annual BAA MWh loss value was then multiplied by a 2028 BAA Average Locational Marginal Price $/MWh, extracted from the Production Cost Model to produce an annualized dollar cost of energy losses.

2. Results

The Table 44 summarizes the energy loss benefit analysis for each of the affected NTTG balancing areas.

[31] Using the same economic parameters described above.

PCM Loss Detail

11/16/2018
2018$

		pRTP BAA Energy Losses		iRTP BAA Energy Losses		Cost of Annual Losses Savings = pRTP - iRTP
Area	Average LMP for Loads ($/MWh)	Calculated Losses (MWh)	Cost of Annual Losses $	Calculated Losses (MWh)	Cost of Annual Losses $	Annual Losses Cost Savings $
IPFE	24	63,996	$1,514,519	63,923	$1,512,805	$1,714
IPMV	24	147,161	$3,600,421	146,991	$3,596,265	$4,156
IPTV	25	352,993	$8,822,441	352,589	$8,812,342	$10,100
NWMT	20	90,135	$1,791,788	90,032	$1,789,744	$2,044
PACW	28	565,556	$15,673,912	564,909	$15,655,980	$17,932
PAID	22	138,601	$3,016,536	138,443	$3,013,096	$3,439
PAUT	21	959,602	$20,153,366	958,504	$20,130,299	$23,066
PAWY	21	222,515	$4,735,250	222,260	$4,729,839	$5,411
PGE	29	639,392	$18,300,719	638,660	$18,279,768	$20,951
NTTG Total		3,179,951	$77,608,952	3,176,311	$77,520,138	$88,813

Table 44 : Average Energy Loss

Table 44 above shows that from a loss perspective, the pRTP case has more energy losses than the iRTP and as such is the less efficient case. Losses are higher in the pRTP because the electrical flows in the iRTP case were redistributed to the new higher voltage, lower impedance lines. Incremental losses in PCM are a function of topology, impedance and injections. As load and generation dispatch is changed hourly, so does incremental losses.

C. Reserve Metric

The reserve metric evaluates the opportunities for two or more parties to economically share a generation resource that would be enabled by transmission. The metric is a 10-year incremental look at the increased load and generation additions in the NTTG footprint and the incremental transmission additions that may be included in the dRTP. In the study cycle, the Gateway West iRTP, Gateway West pRTP, Gateway South and B2H projects were included in the analysis. To evaluate these projects, the NTTG footprint was segmented into zones.

The metric assumes that the parties within the zones share a pro-rata portion of a simple cycle combustion turbine (priced at $800/kw). A preliminary calculation of the reserve metric found that none of the positive reserve benefits exceed $750,000/year over the reserve sharing ability of the existing transmission system. More importantly, there is not a reserve sharing distinction between the pRTP and the iRTP; both plans can support all the positive reserve combinations. Since the iRTP and pRTP transmission plans could contain the same benefit value, the change in Reserve metric does not factor into the dRTP selection decision.

D. Metric Analysis Conclusion – Incremental Cost Comparison

The sum of the annual capital related cost metric, loss metric (monetized) and reserve metric (monetized) calculate the incremental cost for the iRTP and the pRTP. The set of projects within the IRTP or pRTP plans with the lowest incremental cost, after adjustment by the plan's effects on neighboring regions, will then be incorporated within the dRTP.

Annual Incremental Cost
2018$

11/16/2018	iRTP	pRTP	pRTP less iRTP
Capital Related Cost	$903,531,849	$802,814,981	($100,716,868)
Losses - Monitized	$77,520,138	$77,608,952	$88,814
Reserve - Monitized	($750,000)	($750,000)	$0
Incremental Cost	$980,301,987	$879,673,933	($100,628,054)

Table 45 Change Case Metric Estimate Difference from iRTP

IX. Final Regional Transmission Plan

Based on the reliability and economic conclusions discussed above, the more efficient or cost effective plan, based on the studies in this report, is the pRTP which is a staged variant of the IRTP.

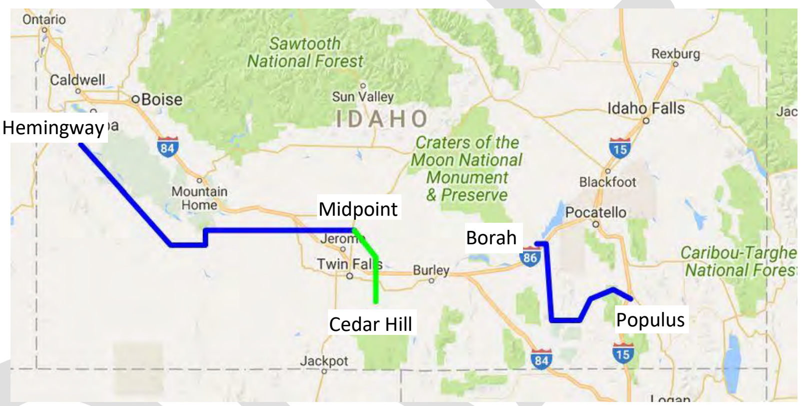


Figure 69 - IRTP segments not included in dRTP

NTTG's dRTP is shown in Figure 70 was selected after a rigorous technical Change Case reliability analysis of NTTG TP's rollup of their local area plans, assumption and Non-Committed regional transmission projects augmented with stakeholder interregional transmission projects. This technical analysis was followed by an economic metric analysis that selected NTTG's more efficient or cost effective Regional Transmission Plan

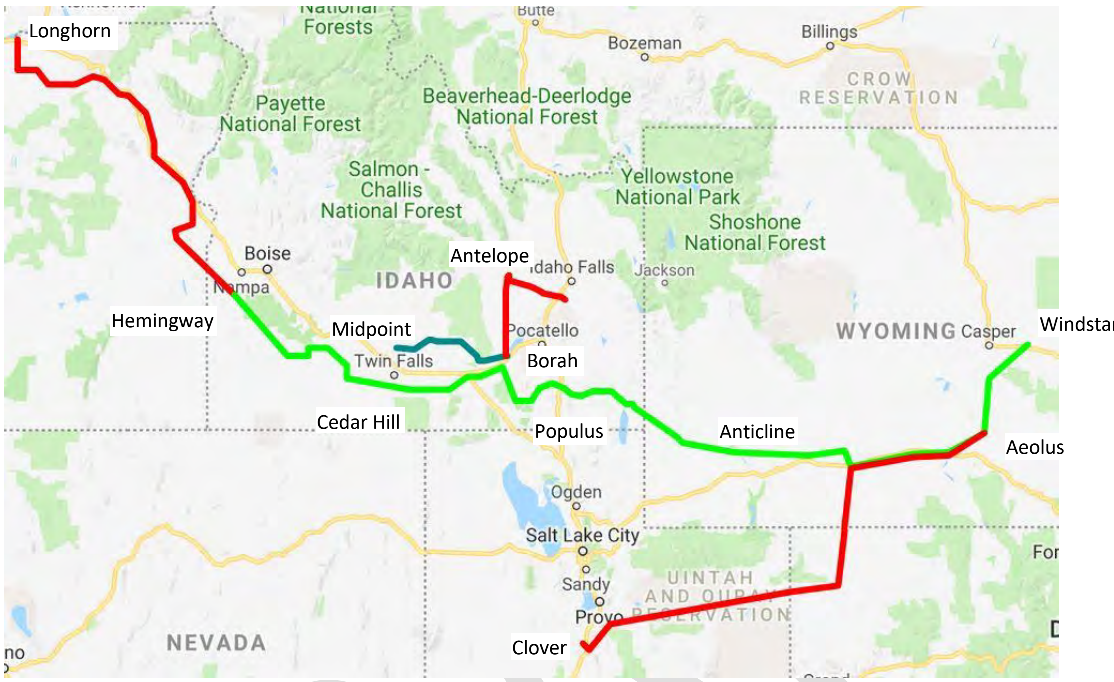


Figure 70 - dRTP Projects

X. Lessons learned in Q1 through Q4

A. Study Plan changes

- The Study Plan was updated to reflect that for the loss metric, only PCM results would be used in the metric analysis.

B. Data submittals in Q1 and Q5

The data submittal form was revised to better capture the desired data. The changes include:

- It was observed that some resource retirements were not submitted. The data submittal form was updated to indicate that retirements should be provided.
- Non-transmission alternative examples were added.

XI. Robustness sensitivity studies - Q5, Q6

In Quarter five, as discussed in Section X below, a three coal replacement scenarios were studied replacing retiring coal units (Bridger and Naughton) with wind resources located in

Wyoming, Utah and the Pacific Northwest. In each of those scenarios, the dfRTP was able to accommodate the additional resource.

In Quarter six, TWG discussed several robustness scenarios including the cost allocation scenarios discussed in the NTTG 2018-19 study plan, specifically a 1000 MW load increase scenario. TWG also considered other scenario sources including the WECC Long Term Planning Scenarios. A higher growth scenario supplied by renewable resources was thought to be the most instructive from these sources.

TWG scaled the NTTG footprint load up by 2000 MW and 4000 MW (8.5% and 17% respectively) to reflect both a higher than expected growth pattern and a longer than 10 year horizon to test the dRTP. The additional energy requirement of this growth was assumed to be supplied by a 50% wind and 50% solar resource mix. The capacity of these resources were determined based on a load factor/capacity factor ratio for each balancing area and located at likely resource locations of the balancing area.

Transmission Provider	2017 Summer Loads	2028 Forecasted Summer Loads	2000 MW Increase over 2028 Summer	4000 MW Increase over 2028 Summer
Idaho Power	3806	4299	4661	5022
Northwestern	1803	2030	2201	2372
PacifiCorp East	8870	9697	10513	11329
PacifiCorp West	3558	3589	3999	4310
Portland General	4023	4060	4402	4743
Total	22060	23775	25775	27775

Table 46 Robustness scenario load targets

Transmission Provider	2000 MW		4000 MW	
	Solar	Wind	Solar	Wind
Idaho Power	489	279	978	559
Northwestern	257	131	515	263
PacifiCorp East	908	537	1817	1073
PacifiCorp West	428	298	855	596
Portland General	474	260	949	520
Total	2557	1506	5114	3011

Table 47 Robustness scenario incremental resources

For each case these installed capacities were scaled to reflect the extracted dispatch hour. For the 2000 MW and 4000 MW scenarios, this resulted in the following net load and resource balance:

2000 MW Net Balance (Solar + Wind – Load)								
	A	B	C	E	F	G	H	I
Idaho Power	-127	-163	-151	-72	-42	-122	-24	-126
Northwestern	-32	-150	-33	22	-93	-115	-113	-32
PacifiCorp East	-27	-321	47	49	-50	-64	85	22
PacifiCorp West	-230	-506	-263	-21	81	1	-455	134
Portland General	120	-336	115	92	-109	-29	162	121
Total	-296	-1476	-286	70	-213	-330	-346	119

Table 48 2000 MW robustness scenario net balance

4000 MW Net Balance (Solar + Wind – Load)								
	A	B	C	E	F	G	H	I
Idaho Power	-254	-325	-302	-143	-83	-245	-49	-251
Northwestern	-64	-299	-67	43	-187	-230	-226	-65
PacifiCorp East	-55	-643	94	98	-100	-127	170	44
PacifiCorp West	-460	-1012	-525	-43	163	1	-910	268
Portland General	240	-672	229	184	-218	-59	324	242
Total	-593	-2951	-572	140	-426	-659	-691	238

Table 49 4000 MW robustness scenario net balance

Most of these scenarios resulted in a NTTG footprint deficit, so the Pacific Northwest area was used supply the balance to the NTTG footprint. In the Heavy Winter case, insufficient energy was available in the Pacific Northwest so additional energy was scheduled in from Canada and California. It is likely that some balancing areas would add gas resources to support these renewable resource additions, however, using external energy purchases would result in increased stress on the dfRTP facilities for this analysis.

To implement the above tables, the NTTG balancing area loads were each uniformly scaled. The wind and solar resources applied to an appropriate bus in each balancing area. In actual practice, load increases would not be uniform and generator interconnection processes would perform studies to determine suitable interconnection facilities and necessary network upgrades. The purpose of this robustness analysis was to identify if facilities in the dfRTP would accommodate these additional loads and resources. It is expected that local area reinforcements may be necessary to accommodate most of these load and resource additions.

Results:

The dfRTP facilities performed well in all of the incremental cases. There were a number of local area issues that surfaced in the Heavy Summer (Case A), Heavy Winter (Case B), and Heavy Import (case H) conditions. Most likely related to the local load increase, the location of the added resources or inadequate tuning of the incremental case. All would be remediated during normal future planning processes.

Case Specific Notes:

- Heavy Summer – Case A
    - NWE: A number of slight branch/transformer load related overloads and few areas of low voltages
    - PACE: A number of slight branch overloads and low voltages occur in the Path C area for a few outages.
    - PACW: A few low voltages occur in the Meridian area for an outage.
    - PGN: A number of branch overloads occur due to the integration of the solar resource at a single backbone bus.
- Heavy Winter – Case B
    - PACE: A number of slight branch overloads and low voltages occur in the Path C area for a few outages.
    - PACW: large increase in low voltages in the Klamath Falls-Meridian Area due to increased loads (from 3 to 62 in the 2000 MW case and from 3 to 95 in the 4000 MW case).
    - PGN: A few of transformer/branch overloads occur due to the increased load.
- Heavy Import – Case H
    - NWE: Few overloads due to increased loads.
    - PACE: A number of low voltages in the Path C area and the St George area.

XII. Public Policy Consideration - Q5

During Quarter one of the NTTG 2018-2019 Regional Planning Cycle, Deseret Power, Utah Association of Energy Users, Utah Associated Municipal Power Systems, Utah Department of Commerce Office of Consumer Services, Utah Municipal Power Agency, and Wyoming Industrial Energy Consumers jointly submitted a Public Policy Consideration ("PPC"), defined in the NTTG Funders' Attachment K, request for a scenario analysis study. This request is to assess the transmission impacts and reliability implications associated with the retirement of Jim Bridger Unit 1 ("Bridger") and Naughton Units 1 and 2 ("Naughton") all three retirements are outside the 2028 study period and the integration of replacement resources for Idaho Power and PacifiCorp. The Study was completed during Quarter five of the study cycle and its report is included as Appendix D.

XIII. Cost Allocation Evaluation - Q6

Since none of the projects selected in the dfRTP have requested cost allocation, these studies have not been performed.

XIV. Economic Study Request – Q7

The NTTG Regional Economic Study Request (ESR) window provides stakeholders with the opportunity to request NTTG to model the ability of specific upgrades or other investments to the Transmission System or Demand Resources, not otherwise considered in the Local Transmission Plans of the NTTG Transmission Providers, to reduce the overall cost of reliably serving the forecasted needs of the NTTG Footprint.

In Quarter five of the NTTG 2018-2019 Biennial Study cycle, Deseret Power on behalf of the "Joint Parties" (Utah Association of Energy Users, Deseret Power, Utah Municipal Power Agency, Utah Department of Commerce Office of Consumer Services and Utah Associated Municipal Power Systems) submitted an ESR to evaluate up to two 345 kV transmission lines as a lower cost alternative to Gateway West and Gateway South. The Study was completed during Quarter seven of the study cycle and its report is included as Appendix E.

Appendix A Public Policy Requirements

This attachment includes all Public Policy Requirements information that was available at the time the revised NTTG Biennial Study Plan was developed:

State	Legislation	Requirement or Goal
California	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond Based on the retail load for a three- or four-year compliance period
Idaho	• No RPS Requirement	•
Montana	• SB 45 2013 • SB 325 2013	• 5% by 2008-09 • 14% by 2010-14 • 15% by 2015 and Beyond
Oregon	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 Based on the retail load for that year
Utah	• Senate Bill 202 (2008)	• Goal of 20% by 2025 (must be cost effective • Annual targets are based on the adjusted[1] retail sales for the calendar year 36 months prior to the target year
Washington	• Initiative Measure No. 937 (2006)	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond • Annual targets are based on the average of the utility's load for the previous two years
Wyoming	• No RPS Requirement	

[1] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM.

Appendix B 2028 ADS Case Resource Changes

Resource Additions and Removals to the 2028 Anchor Data Set

Changes to the WECC 2028 ADS Case include:

- Retirements
  - Dave Johnson 1, 2, 3 and 4
  - Naughton 3 Gas Unit (converted coal unit)
  - Valmy 1 and 2

- Additions
  - Idaho Power
    - Solar – 4 Projects, 24 MW
  - Northwestern
    - Solar – 1 Project, 80 MW
    - Wind – 5 Projects, 540 MW
  - PacifiCorp – Oregon
    - Solar – 13 Projects, 118 MW
    - Wind – 6 Projects, 60 MW
  - PacifiCorp – Utah
    - Solar – 2 Projects, 106 MW
    - Wind – 1 Project, 79 MW
  - PacifiCorp – Wyoming
    - Solar – 1 Projects, 58 MW
    - Energy Vision 2020 Wind – increased from 1100 MW to 1311 MW
    - Wind – 1 Project, 320 MW

Appendix C Path Flows

Path Flows in a selected number of Power Flow Change Cases

NTTG Case Path Flows												
				Interface MW Flow								
Number	Name	MW Forward Limit	MW Reverse Limit	Heavy Summer - Case A-v1d	Heavy Winter - Case B-v1c	High Eastbound Idaho-NW Case C-v1f	High Idaho-NW export - Case D-v1b	High Tot2/COI/ PDCI Case E-v1d	High Wyoming Wind - Case F-v1c	High Borah West - Case G-v1e	High NTTG Footprint Import Case H-v1b	High Aeolus West&South Case I-v1c
1	ALBERTA - BRITISH COLUMBIA	1000	-1200	-863	-261	-491	-329	410	-456	368	-297	-494
2	ALBERTA - SASKATCHEWAN	150	-150	0	0	0	0	0	0	0	0	0
3	NORTHWEST - CANADA	3000	-3150	-1622	-431	508	-395	-14	385	405	-1287	498
4	WEST OF CASCADES - NORTH	10200	-10200	3011	6529	4794	3475	6038	4564	4034	4049	5793
5	WEST OF CASCADES - SOUTH	7200	-7200	3241	4831	2598	3425	3688	3256	3076	4060	3210
6	WEST OF HATWAI	4277		-525	-160	639	-169	2129	546	41	29	1357
8	MONTANA - NORTHWEST	2200	-1350	-320	410	-111	319	1239	1106	826	220	551
9	WEST OF BROADVIEW	2573		826	1147	209	936	1326	1502	1239	1016	895
10	WEST OF COLSTRIP	2598		1577	1580	856	747	1775	1537	1354	1556	1474
11	WEST OF CROSSOVER	2598		1609	1645	678	1099	1690	1751	1543	1620	1361
14	IDAHO - NORTHWEST	3400	-2250	-1117	1368	-1970	1415	-428	2827	2562	-949	-984
15	MIDWAY - LOS BANOS	4800	-2000	-105	2357	-1461	2491	-1214	3333	4123	1280	-716
16	IDAHO - SIERRA	500	-360	-115	-101	115	-40	179	-50	-123	-171	110
17	BORAH WEST	3600		61	1635	-843	2089	497	3367	3403	-110	-198
18	MONTANA - IDAHO	337	-256	159	-37	170	-159	176	-236	-253	84	151
19	BRIDGER WEST	2400	-600	1660	1672	532	1754	1679	1881	1497	817	729
20	PATH C	2250	-2250	1332	99	1507	507	1731	-428	-882	731	1776
25	PACIFICORP/PG&E 115 KV INTERCON.	100	-45	61	59	63	62	60	60	59	60	63
26	NORTHERN - SOUTHERN CALIFORNIA	4000	-3000	1635	-2046	957	-1759	601	-3039	-3897	304	187
27	IPP DC LINE	2400	-1400	1242	1288	2186	1849	2406	2159	1240	1530	2406
28	INTERMOUNTAIN - MONA 345 KV	1400	-1200	389	265	-489	-253	-812	-591	275	260	-760
29	INTERMOUNTAIN - GONDER 230 KV	200		-34	41	-38	0	0	41	80	-60	-51
30	TOT 1A	650		-3	144	13	52	-109	169	7	282	-78
31	TOT 2A	690		105	125	16	36	19	8	111	25	15
32	PAVANT, INTRMTN - GONDER 230 KV	440	-235	-63	70	-53	59	23	107	146	-108	-64
33	BONANZA WEST	785		-226	-316	-228	-343	-300	-373	-257	-384	-303
34	TOT 2B	780	-850	-58	-62	103	-72	43	26	2	-36	16
35	TOT 2C	600	-580	-20	2	47	72	174	144	65	-195	18
36	TOT 3	1680		928	661	365	960	1231	931	609	339	1527
37	TOT 4A	810		-95	-37	46	-18	101	97	42	25	179
38	TOT 4B	680		-7	136	-40	154	-84	46	69	133	-99
39	TOT 5	1680		461	390	170	339	136	335	338	291	537
40	TOT 7	890		223	175	102	233	230	246	177	43	377
41	SYLMAR - SCE	1600	-1600	-270	1422	108	54	248	565	935	-19	45
65	PACIFIC DC INTERTIE (PDCI)	3100	-3100	1652	1121	2781	125	1686	2241	2241	497	2781
66	COI	4800	-3675	2072	1802	4296	288	4767	-378	-855	914	3755
71	SOUTH OF ALLSTON	3980	-1115	2299	1430	709	672	667	106	146	1328	700
73	NORTH OF JOHN DAY	7700	-7700	3584	3185	4168	1144	4321	278	545	2932	4371
75	MIDPOINT - SUMMER LAKE	1500	-550	-149	949	-159	871	596	1308	1231	-121	165
76	ALTURAS PROJECT	300	-300	176	110	180	153	177	101	87	175	178
77	CRYSTAL - ALLEN	950		131	18	126	78	3	76	88	145	108
80	MONTANA SOUTHEAST	600	-600	238	-191	377	-510	300	-286	-253	128	172
83	MATL	325	-300	-243	-266	-327	-299	-264	-303	-310	-177	-325

Appendix D Public Policy Consideration Study

NORTHERN TIER TRANSMISSION GROUP

NTTG Study Report
for the
2018-2019 Public Policy Consideration Scenario

NTTG Study Report
for the
2018-2019 Public Policy Consideration Scenario

Table of Contents

1. Background

During Quarter 1 of the NTTG 2018-2019 Regional Planning Cycle, Deseret Power, Utah Association of Energy Users, Utah Associated Municipal Power Systems, Utah Department of Commerce Office of Consumer Services, Utah Municipal Power Agency, and Wyoming Industrial Energy Consumers jointly submitted a Public Policy Consideration ("PPC"), defined in the NTTG Funders' Attachment K, request for a scenario analysis study. This request is to assess the transmission impacts and reliability implications associated with the retirement of Jim Bridger Unit 1 ("Bridger") and Naughton Units 1 and 2 ("Naughton")[32] all three retirements are outside the 2028 study period and the integration of replacement resources for Idaho Power and PacifiCorp. See PPC study plan in Attachment 1.

The PPC Study Plan, approved July 2018, assumed Idaho Power's share of the jointly owned Jim Bridger Unit 1 would be replaced with purchases from the Pacific Northwest[33] and the replacement energy for PacifiCorp's share of Jim Bridger Unit 1 and Naughton Units 1 and 2 was deferred. Since the PacifiCorp 2019 IRP update is underway and results are not expected until summer 2019. The NTTG Technical Workgroup ("TWG") reviewed the PPC request and identified three resource bracketing scenarios to test the impact of likely PacifiCorp replacement resources; 1) wind resources in Wyoming, 2) wind resources in Utah and 3) resources located in the Pacific Northwest.

The TWG reviewed the requested powerflow cases: High Wyoming Wind (Case F), High Southern Idaho export (Case D), and High Southern Idaho import (Case C). However, upon further examination Case D was dropped from further study because that case flows did not achieve the desired objectives; any subsequent study of the that case would not have provided useful information. The Draft Regional Transmission Plan (DRTP) replaced Case D with two other cases: the High Borah West (Case G), and the High Aeolus South and West (Case I) cases.

For reference, the existing and planned 2028 Wyoming resources are listed in the following table. The replacement resources being considered in this study are in addition to the 2028 Planned Resources and vary in size and location:

	Thermal	Wind	Solar	Total
Existing (2018)	3155	1334	0	4489
Planned	-1042	1613	138	727
Total in 2028	2113	2949	138	5216
Beyond 2028	-913[34]	Varies	0	Varies

[32] Units already modeled as retired in NTTG 2018-2019 studies include: Boardman, Cholla Unit 4, Colstrip units 1 and 2, Dave Johnson Units 1-4, Naughton Unit 3 and Valmy Units 1 & 2.

[33] In powerflow studies the removal of resources must be replaced in kind with output from other resources. If none are provided, the area swing generators will pick up the lost output potentially overloading those generators and likely not representing the appropriate new resource location.

[34] Jim Bridger Unit 1, Naughton Unit 1 and Unit 2.

Table 1 – Wyoming Resources, existing and future changes included in studies

2. Study Assumptions

The following assumptions were applied to the scenarios to retire PacifiCorp resources.

- Solar resources were considered for the makeup of the PacifiCorp energy, but three of the four PPC study cases were extracted from a night time hour. So, contribution to the capacity deficit would be zero in those hours. As a result, the study's focus was on replacement renewable wind resources.
- The DRTP cases had the following dispatch of the Bridger and Naughton resources:

	Case C	Case F	Case G	Case I
Bridger 1	-212.3	-523.3	-523.0	-212.0
Naughton 1	-130.7	-141.6	-201.0	-200.0
Naughton 2	Off-line	-220.0	-201.0	-200.0
Total dispatch change	-343.0	-884.6	-830.0	-556.9
Idaho Power's Share	70.8	174.3	174.3	70.7
PacifiCorp Share	272.2	710.3	655.7	486.2

Table 2 – PPC Study Retirements and Idaho Power's and PacifiCorp's replacement energy requirements in Powerflow study

- For Idaho Power's share of the retirements, the study plan indicated its replacement resource would come from the Pacific Northwest via the proposed B2H project. For this study, the TWG used the large resource at Coulee as a proxy for additional energy.
- For the wind scenarios #1 and #2, see Table 1 below, the wind capacity needed to be determined with the tools available to the TWG. The TWG concluded that there is no industry criteria that could be used for determining an appropriate capacity for this study. Subsequently, the TWG, using the wind profiles in adjacent projects, adjusted the installed capacity levels until two of the four cases had surplus wind energy and two required additional energy from other available dispatchable resources.
    - For the Wyoming wind Scenario #1, 850 MW of installed capacity appeared to be reasonable.
    - In Scenario #2, the Utah wind profiles appeared to be of a lower capacity factor for the hours selected than the Wyoming wind profiles, so installed capacity was increased to 1025 MW to compensate.

- In summary, for PacifiCorp share of the retirements the following adjustments were made:

	Case C	Case F	Case G	Case I	Capacity
Scenario 1					
Evanston	40.8	137.7	114.2	145.2	150
Rock Springs	68.1	229.5	190.3	242.0	250
Aeolus	122.5	413.1	342.6	435.7	450
Utah Coal	40.8	-70.0	8.6	-336.7	
Scenario 2					
Pinto	113.0	138.1	109.7	113.0	200
Blackrock	466.3	569.7	452.5	466.1	825
Utah Coal/Gas	-307.1	2.5	93.5	-92.8	
Scenario 3					
Coulee	272.2	710.3	655.7	486.2	

Table 3 – PacifiCorp's replacement energy in bracketing scenarios

- It should be noted that this study has used the net flow as modeled in the typical PCM and powerflow studies. The TWG did not perform an assessment to determine whether there would be sufficient contract capacity in the B2H project to support the additional transfers contemplated in Scenario #3 for PacifiCorp's replacement energy from the Pacific Northwest.
- For each of the four selected cases, these three bracketing resource scenarios were applied, totaling 12 separate base cases.
- To each of these base cases, the following Change Case configurations was tested:

  Change Case Description
  - Null: no future transmission facilities
  - dRTP: Facilities included in the Draft Regional Transmission Plan
  - CC4: included Gateway West without Gateway South
  - CC5: included Gateway South without Gateway West
  - CC31: dRTP without Populus-Cedar Hill-Hemingway 500 kV
  - CC32: CC31 configuration adding Populus-Borah 500 kV
  - CC33: CC31 configuration without Anticline-Populus 500 kV

3. Base cases

NTTG used the WECC ADS 2028 case in its 2018-2019 studies, edited the case to incorporate fixes to load shapes, modified resource retirements/additions not included in the WECC 2028HS1a case, plus other adjustments that improved the accuracy of the dataset. The production cost model simulating the

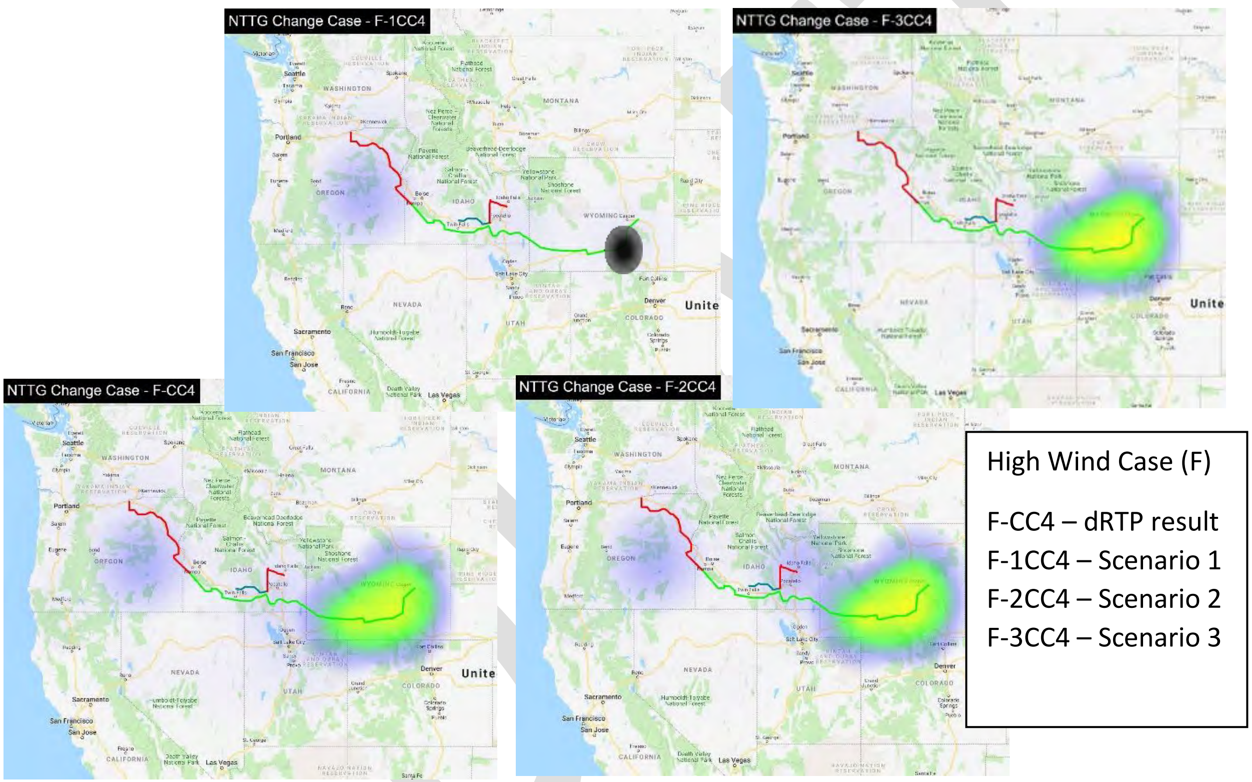
2028 load and resources forecast was used to identify stressed system conditions (i.e., load and generation dispatch conditions) to study. A production cost model uses the costs of operating a fleet of generators within the western interconnection to minimize costs for the 8760 hours of the year while simultaneously adhering to a wide variety of operating constraints.

The production cost model data for the nine selected system conditions were then translated into power flow base cases. A power flow model is a numerical analysis of a single condition flow (e.g., hour) of electric power in an interconnected system. Of the nine selected cases, four were used as described in section 1. See Attachment 2 for powerflow case flow detail.

4. Power Flow Analysis Results; Steady State and Post Disturbance

All analyses involved both steady state power flow and contingency runs. The contingencies include 36 credible double and 445 single contingencies in this analysis.

For the transmission configuration with Gateway West without Gateway South (Change Case CC4):

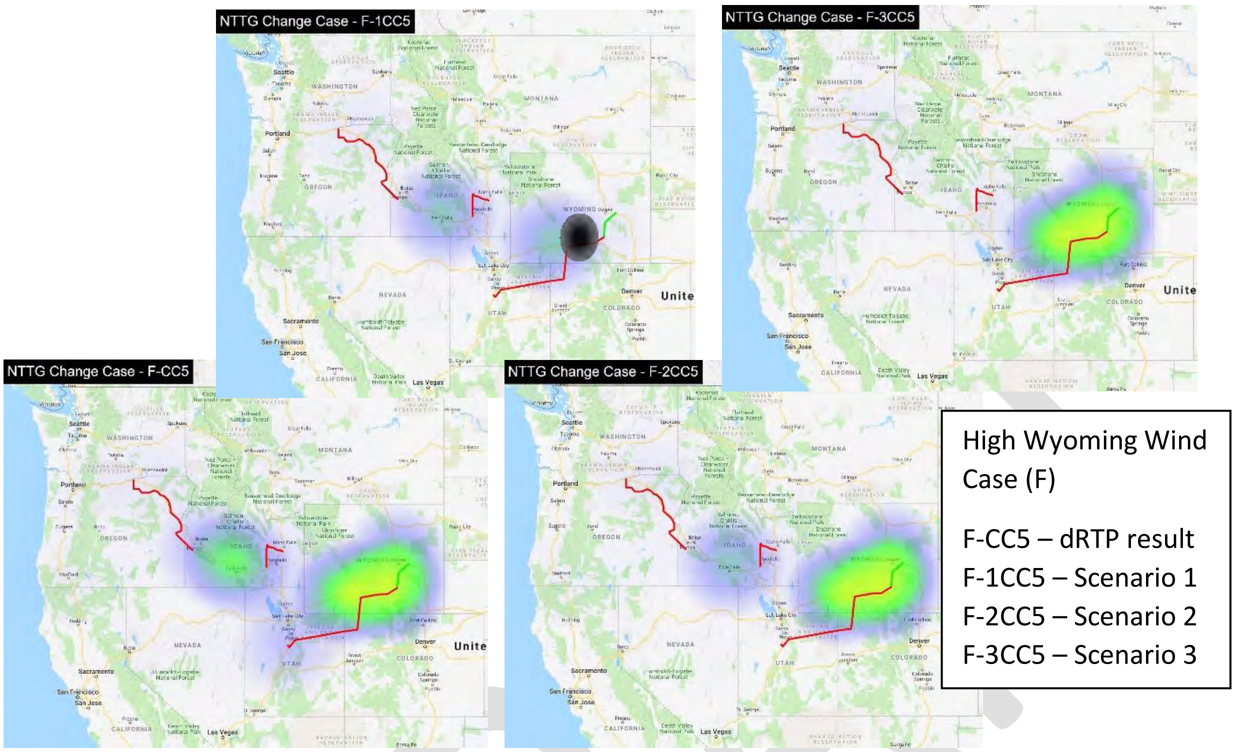


Figures 1 through 4 – Heatmap results for Change Case CC4

Observations

The performance issues illustrated in these heatmaps are the result of overloads due to the loss of the Gateway West project in Wyoming causing overloads of the existing transmission system. These overloads are mitigated in the DRTP by the inclusion of Gateway South.

For the transmission configuration with Gateway South without Gateway West (Change Case CC5), both projects are necessary to move the wind energy out of Wyoming. The retired resources are in the southwestern portion of Wyoming with over half of the retired resource at Bridger. These retired Bridger resources are more tightly associated with the Southern Idaho system than Wyoming. The contemplated wind resource additions in eastern Wyoming exceed the retired capacity because of the lower capacity factor renewable resource:



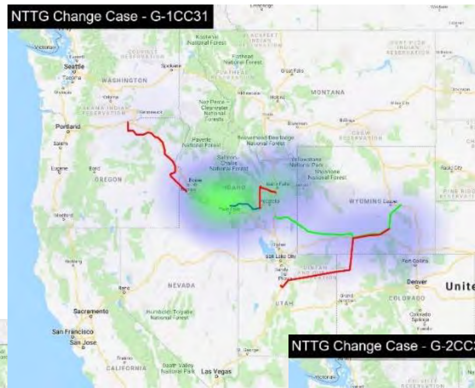
Figures 5 through 8 – Heatmap results for Change Case CC5

Observations

The performance issues illustrated in these heatmaps are the result of overloads due to the loss of the Gateway South project in Wyoming causing overloads of the existing transmission system. These overloads are mitigated in the DRTP by the inclusion of Gateway West.

The dRTP report found that the Populus-Hemingway segment was needed to mitigate transmission overloads in the southern Idaho system. The following heat maps show the result of the dRTP result versus the three scenarios used in this study.

Figures 9 through 12 – Heatmap results for Change Case CC31



High Borah West Case (G)

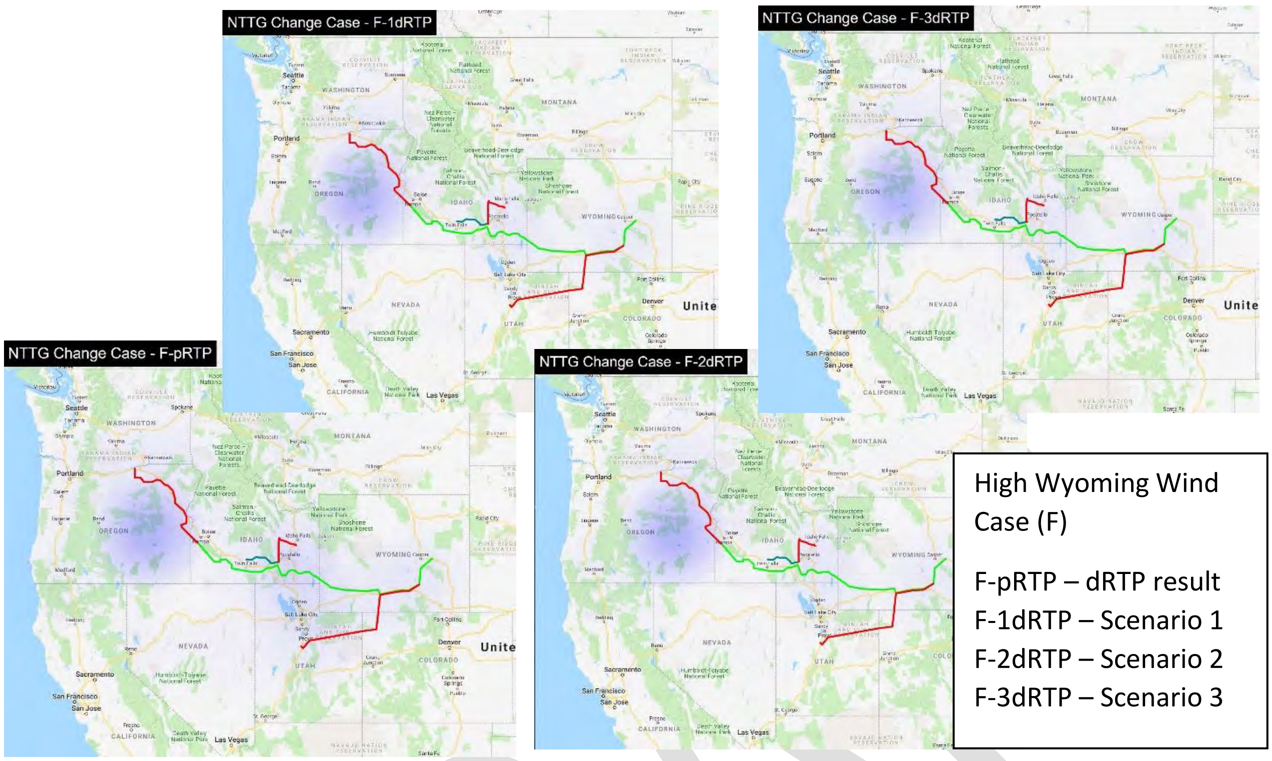
G-CC31 – dRTP result
G-1CC31 – Scenario 1
G-2CC31 – Scenario 2
G-3CC31 – Scenario 3

Observations

The performance issues illustrated in these heatmaps are the result of overloads due to the loss of the Gateway West project in Idaho causing overloads of the existing transmission system. These overloads are mitigated in the DRTP by the inclusion of some segments of Gateway West in Idaho (Populus-Cedar Hill-Hemingway). Conversion of the Borah-Midpoint section of the Kinport-Midpoint 345 kV line does not materially resolve these performance issues as the issues are west of Midpoint in these cases.

Having the replacement energy located in the Pacific Northwest (Scenario 3) could potentially defer the need the Populus-Cedar Hill-Hemingway segment, as shown in case G-3CC31 (Figure 12).

The bracketing scenarios provided an opportunity to test the robustness of the dRTP configuration. This PPC study found that the dRTP configuration accommodates all three resource bracketing scenarios. For example, in Case F, shown below, there isn't a practical difference between the original study resource scenario and this studies' three alternative scenarios:



Figures 13 through 16 – Heatmap results for the DRTP

5. Observation Summary

The Study Plan requested a review of the following DRTP segments:

- Anticline – Populus 500 kV & Aeolus – Clover 500 kV
  - Necessary to integrate the projected Wind capacity in Wyoming
  - Anticline – Populus 500 kV necessary to support outage of Aeolus-Clover (see results from CC5)
  - Aeolus – Clover 500 kV necessary to support outage of Aeolus-Anticline (see results from CC4)
- Populus – Cedar Hill 500 kV & Cedar Hill – Hemingway 500 kV (see results from CC31)
  - Necessary to avoid overloads in Southern Idaho
- Populus – Borah 500 kV
  - Not part of dRTP but would partially mitigate a Populus-Hemingway removal
- Borah – Midpoint 500 kV & Borah 500/345 kV transformer (uprating the Borah-Midpoint section of the existing Kinport-Midpoint 345 kV)
  - Upgrade necessary to support increased westbound transfers with Populus-Cedar Hill-Hemingway
- Midpoint – Hemingway #2 500 kV
  - Not part of dRTP. Needed at higher Borah West transfers than modeled in 2028
- Midpoint – Cedar Hill 500 kV
  - Not part of dRTP. Needed at higher Borah West transfers than modeled in 2028

Attachment 1
Public Policy Consideration Study Proposal for a Scenario Analysis:

Objective

On May 9, 2018, the NTTG Planning Committee approved studying a Public Policy Consideration (PPC) request submitted by Deseret Power, Utah Associate of Energy Users, Utah Associated Municipal Power Systems, Utah Office of Consumer Services, Utah Municipal Power Agency, and Wyoming Industrial Energy Consumers.

These Joint Submitters requested NTTG study the retirement of additional coal fired generation not being considered in the 2018-2028 NTTG 10-year planning window. These coal retirements have been identified in NTTG members' Integrated Resource Plans (IRPs). NTTG will remove this additional coal generation and perform a power flow transmission reliability assessment utilizing base cases that will be developed as part of the 2018-2019 planning cycle.

Base Case Building Process and Assumptions

As part of the NTTG 2018-2019 cycle, NTTG will undertake the development and study of several power flow base cases. This PPC study will utilize the base cases that are developed to be studied in the 2018-2019 cycle representing stressed conditions on the system such as:

1) High Wyoming Wind
2) High Southern Idaho Export
3) High Southern Idaho Import

For each of the relevant cases, the following coal generation should be modeled as off-line:

- Boardman
- Jim Bridger 1
- Cholla 4
- Colstrip 1 & 2
- Dave Johnston 1, 2, 3 & 4
- Naughton 1 & 2
- Naughton 3
- Valmy 1 & 2

Note: The units underlined above will be modeled as off-line in all 2018-2019 NTTG studies.

Make-up power for the units taken off-line should attempt to be consistent with the planned resource additions of the respective company's most recent IRPs and consider individual company's available transmission capacity.

For Idaho Power, make-up power for Jim Bridger 1 should be dispatched from either (1) internal Idaho Power resources, or (2) the Pacific Northwest across the Boardman to Hemingway 500 kV transmission line.

PacifiCorp's make-up power for Jim Bridger 1, and Naughton 1 & 2, will be developed using available 2019 IRP information in consultation with the PPC submitters and Planning Committee.

Study Process

The NTTG TWG will ultimately create and run powerflow contingency analysis on the relevant cases, such as:

1) High Wyoming Wind _ PPC
2) High Southern Idaho Export _ PPC
3) High Southern Idaho Import _ PPC

Given all previous assumptions, the NTTG Technical Working Group, through contingency analysis on the cases, will determine if any of the following Energy Gateway segments are superfluous to the specific power flow case:

- Anticline – Populus 500 kV
- Aeolus – Clover 500 kV
- Populus – Cedar Hill 500 kV
- Cedar Hill – Hemingway 500 kV
- Populus – Borah 500 kV
- Borah – Midpoint 500 kV & Borah 500/345 kV Transformer (uprating Kinport-Midpoint 345 kV)
- Midpoint – Hemingway #2 500 kV
- Midpoint – Cedar Hill 500 kV

Note: It is unknown which facilities will be included into the Draft Regional Transmission Plan. Those lines not included in the Draft Regional Transmission Plan will be removed from this PPC analysis.

Study Schedule

This analysis is scheduled to be completed in Quarter 6 of the 2018-2019 Biennial Planning Cycle.

Deliverable

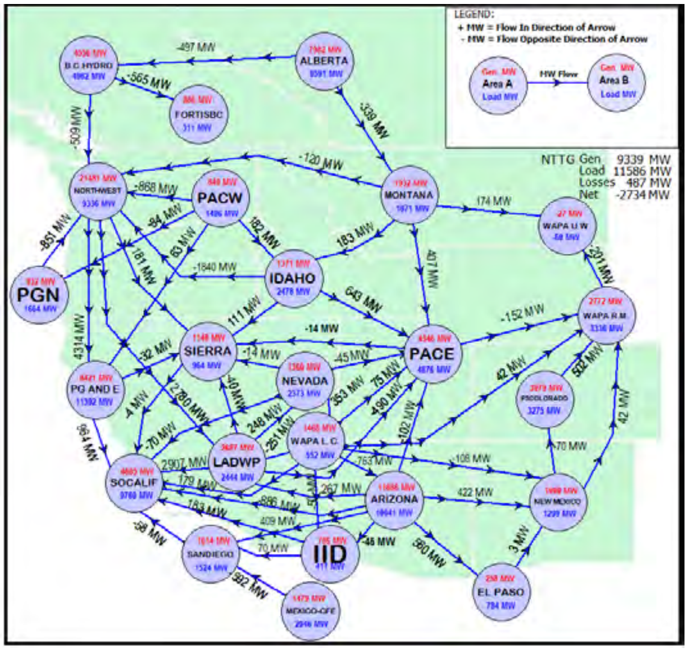
A final PPC Study Report will document the results and will be incorporated, as an attachment, into the final NTTG 2018-2019 Biennial Transmission Plan. The results of this additional analysis are informational only and may inform the 2018-2019 Regional Transmission Plan, but will not result in the inclusion of additional projects or exclusion of projects in the Regional Transmission Plan.

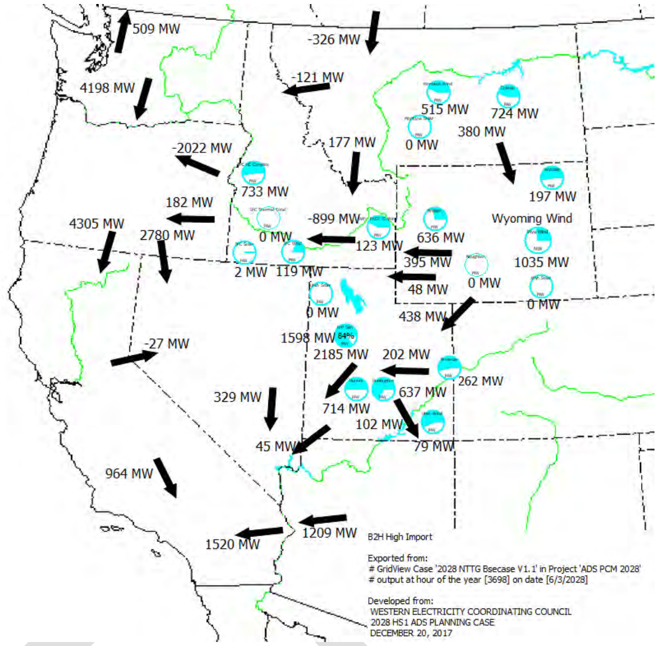
Attachment 2
Powerflow Base Case maps

Table of cases:

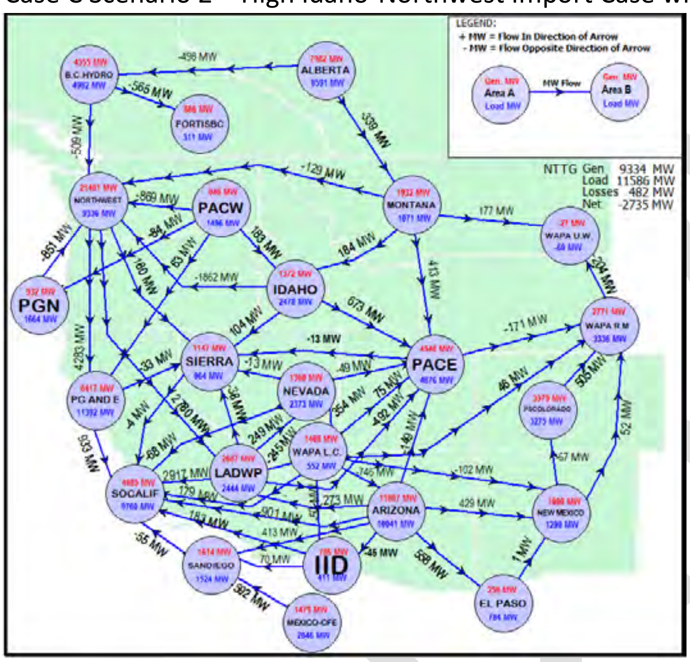
Case C Scenario 1 -	High Idaho-Northwest Import case with Wyoming Wind Replacement Energy
Case C Scenario 2 -	High Idaho-Northwest Import case with Utah Wind Replacement Energy
Case C Scenario 3 -	High Idaho-Northwest Import case with Pacific Northwest Replacement Energy
Case F Scenario 1 -	High Wyoming Wind case with Wyoming Wind Replacement Energy
Case F Scenario 2 -	High Wyoming Wind case with Utah Wind Replacement Energy
Case F Scenario 3 -	High Wyoming Wind case with Pacific Northwest Replacement Energy
Case G Scenario 1 -	High Borah West case with Wyoming Wind Replacement Energy
Case G Scenario 2 -	High Borah West case with Utah Wind Replacement Energy
Case G Scenario 3 -	High Borah West case with Pacific Northwest Replacement Energy
Case I Scenario 1 -	High Aeolus West and South case with Wyoming Wind Replacement Energy
Case I Scenario 2 -	High Aeolus West and South case with Utah Wind Replacement Energy
Case I Scenario 3 -	High Aeolus West and South case with Pacific Northwest Replacement Energy

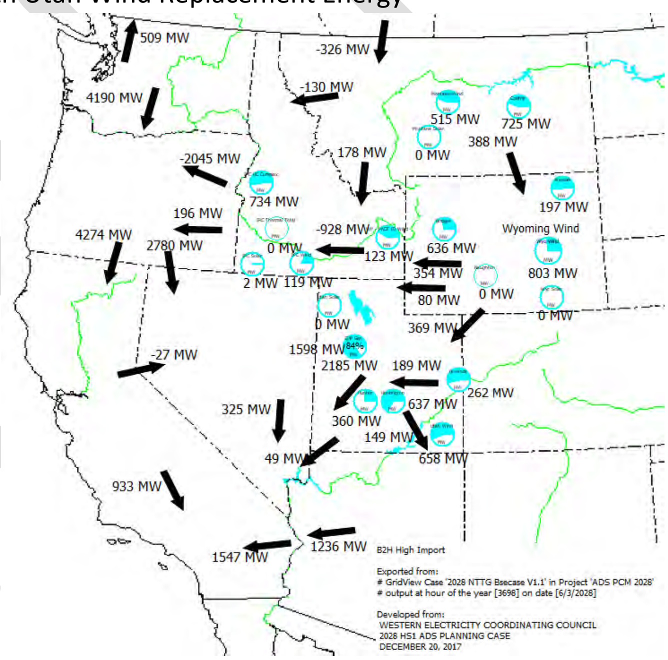
Case C Scenario 1 – High Idaho-Northwest Import Case with Wyoming Wind Replacement Energy



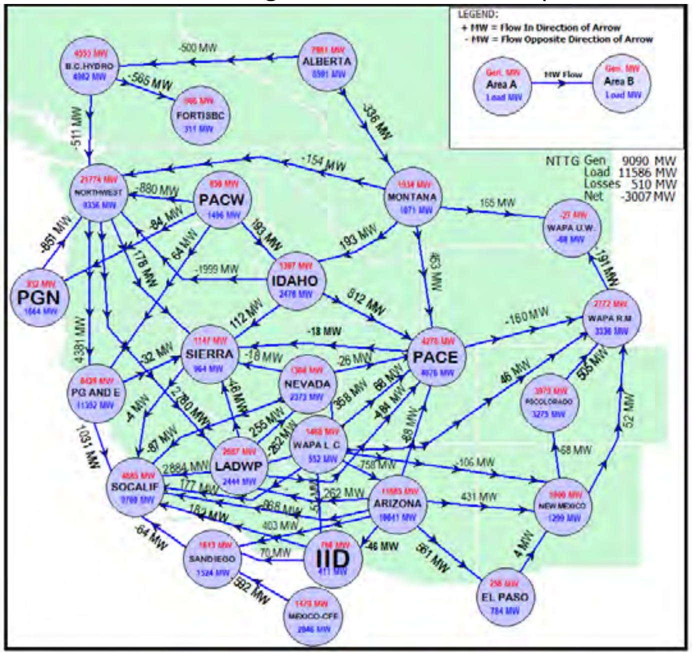


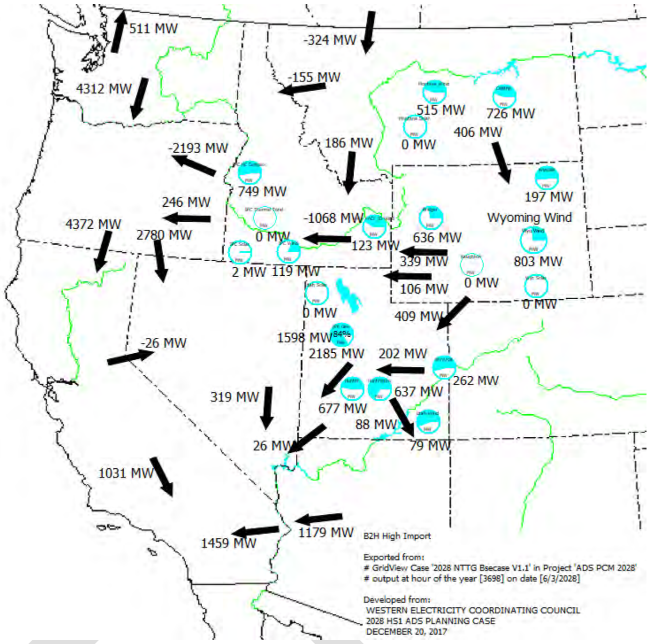
Case C Scenario 2 – High Idaho-Northwest Import Case with Utah Wind Replacement Energy



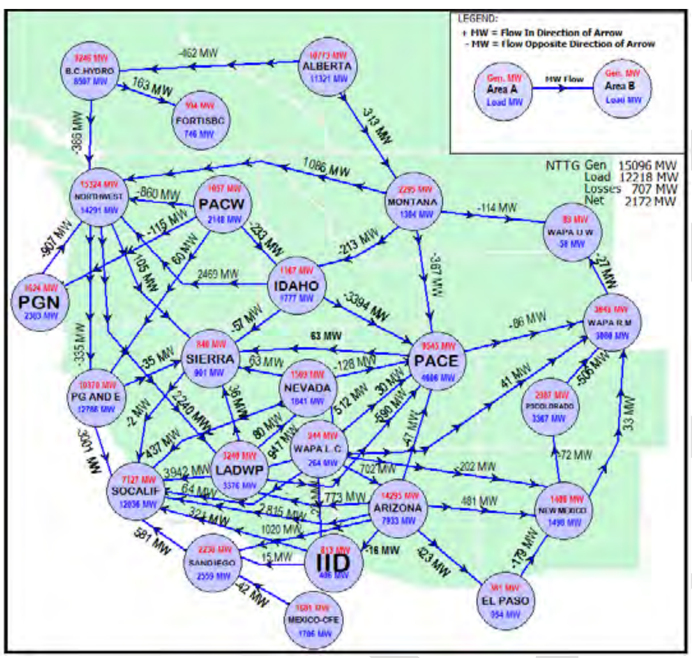


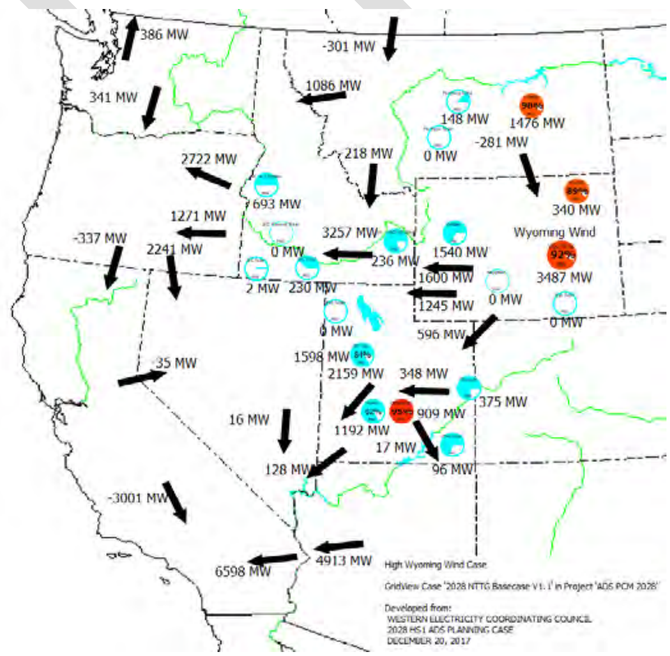
Case C Scenario 3 – High Idaho-Northwest Import Case with Pacific Northwest Replacement Energy



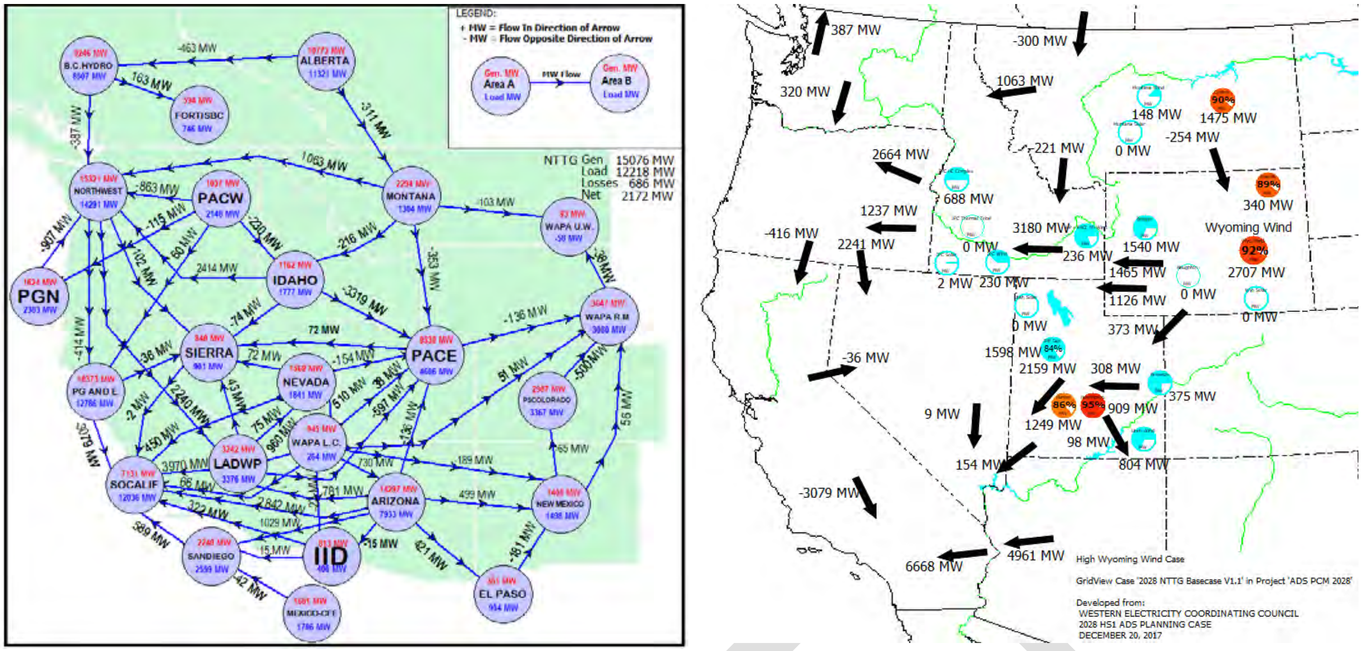


Case F Scenario 1 – High Wyoming Wind Case with Wyoming Wind Replacement Energy

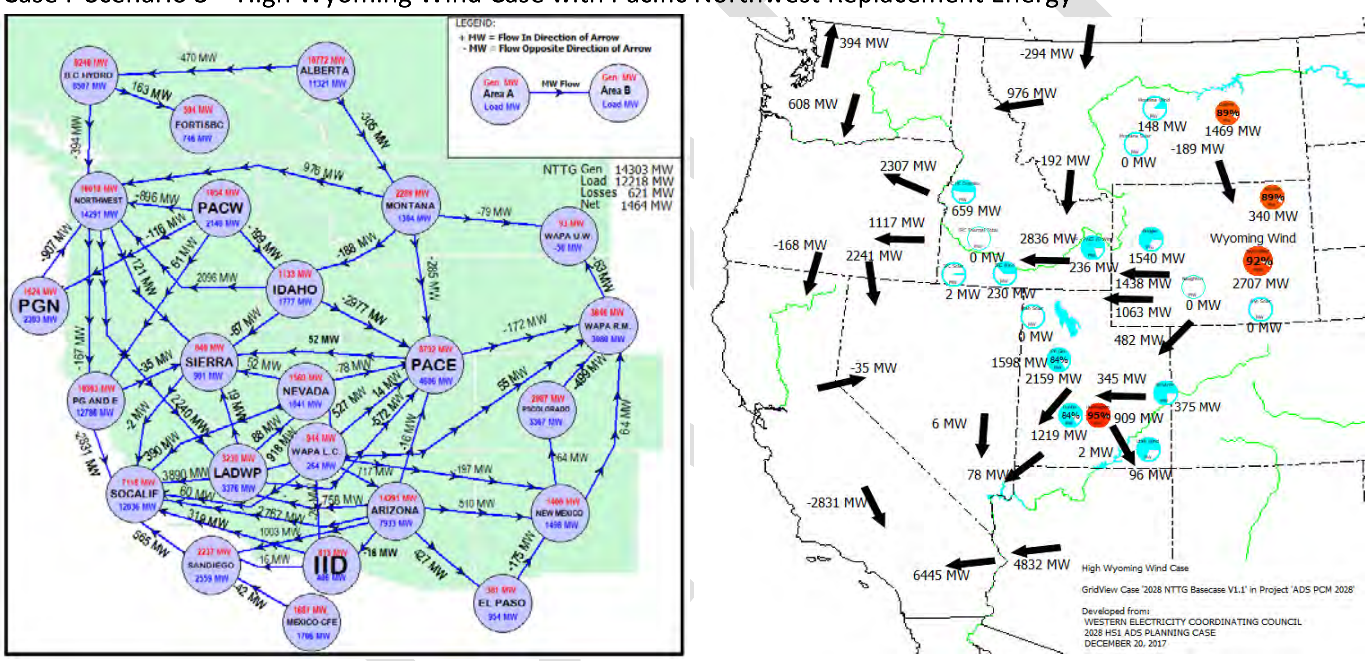




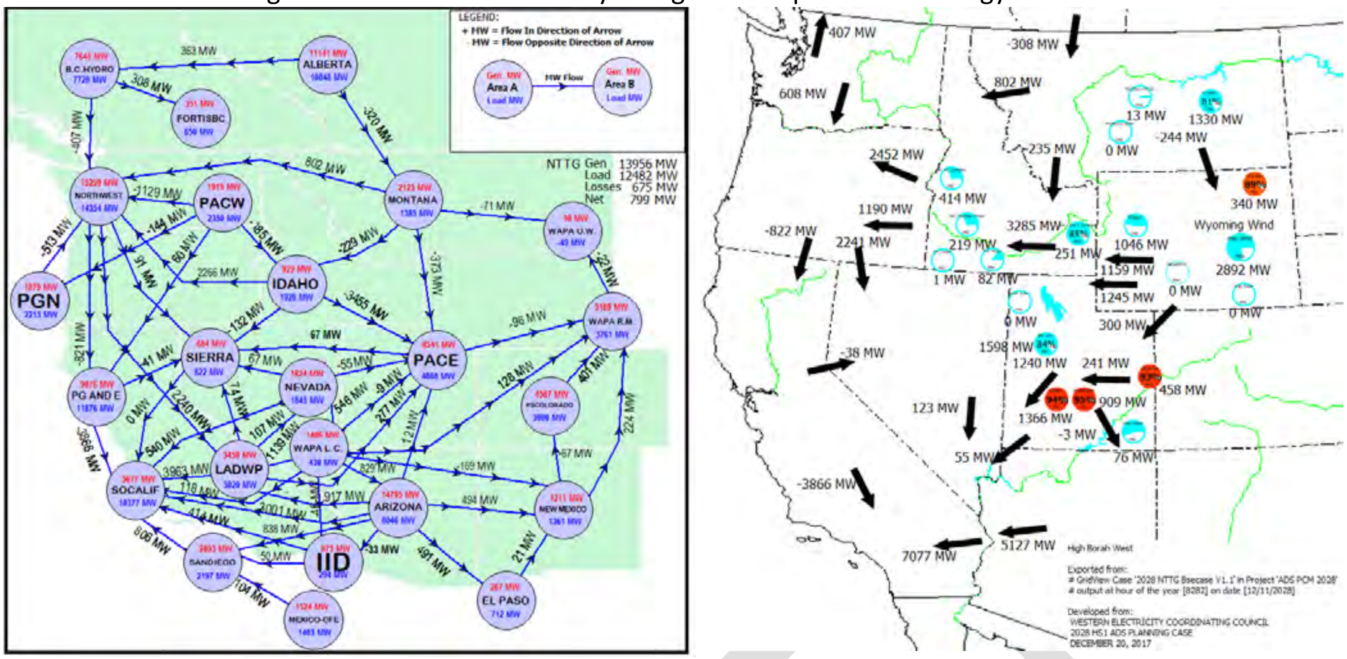
Case F Scenario 2 – High Wyoming Wind Case with Utah Wind Replacement Energy



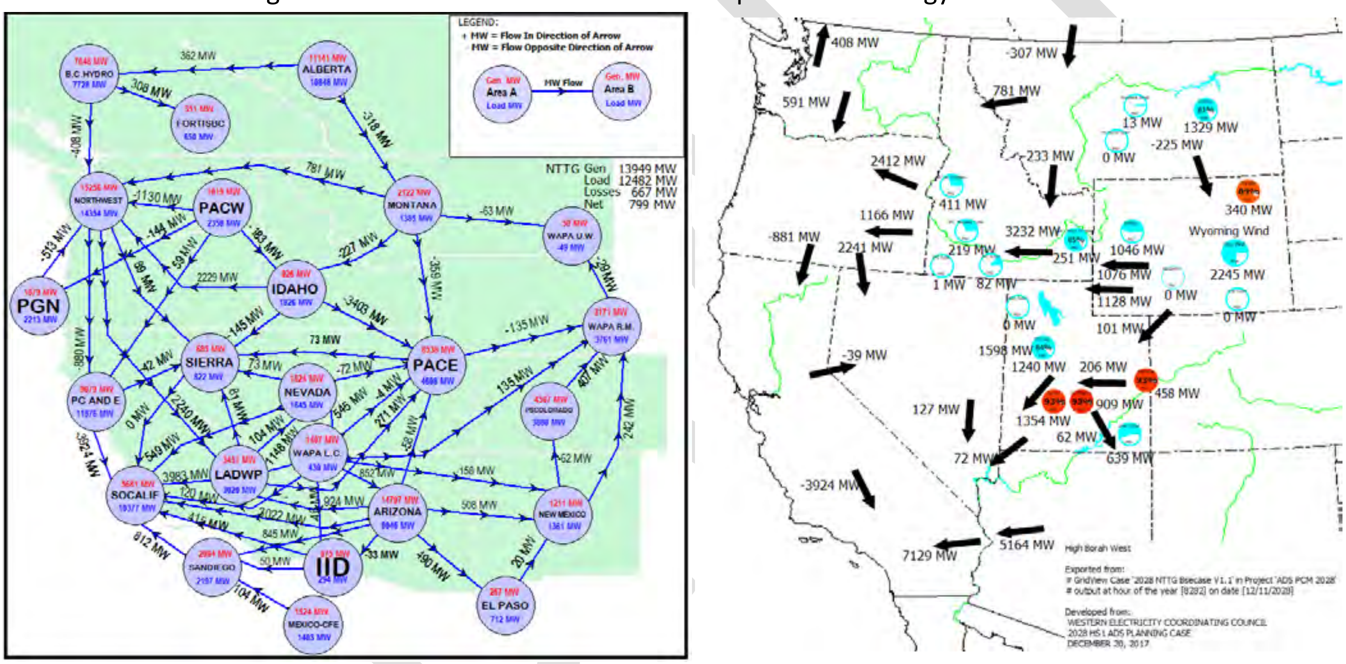
Case F Scenario 3 – High Wyoming Wind Case with Pacific Northwest Replacement Energy



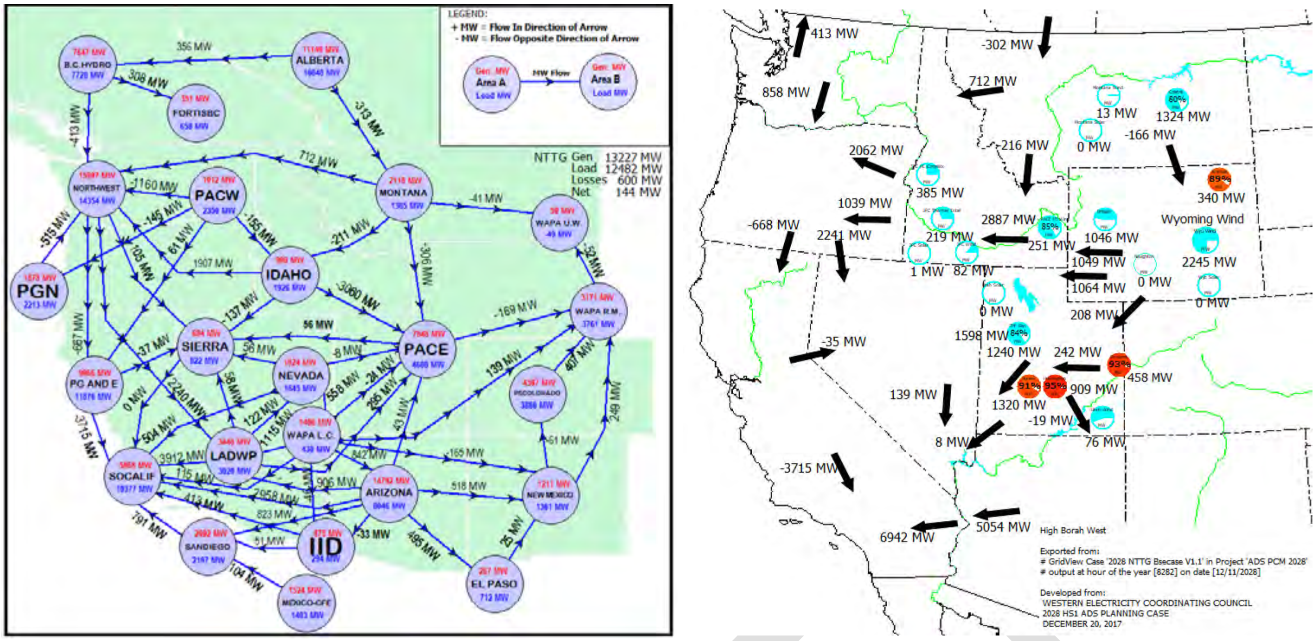
Case G Scenario 1 – High Borah West Case with Wyoming Wind Replacement Energy



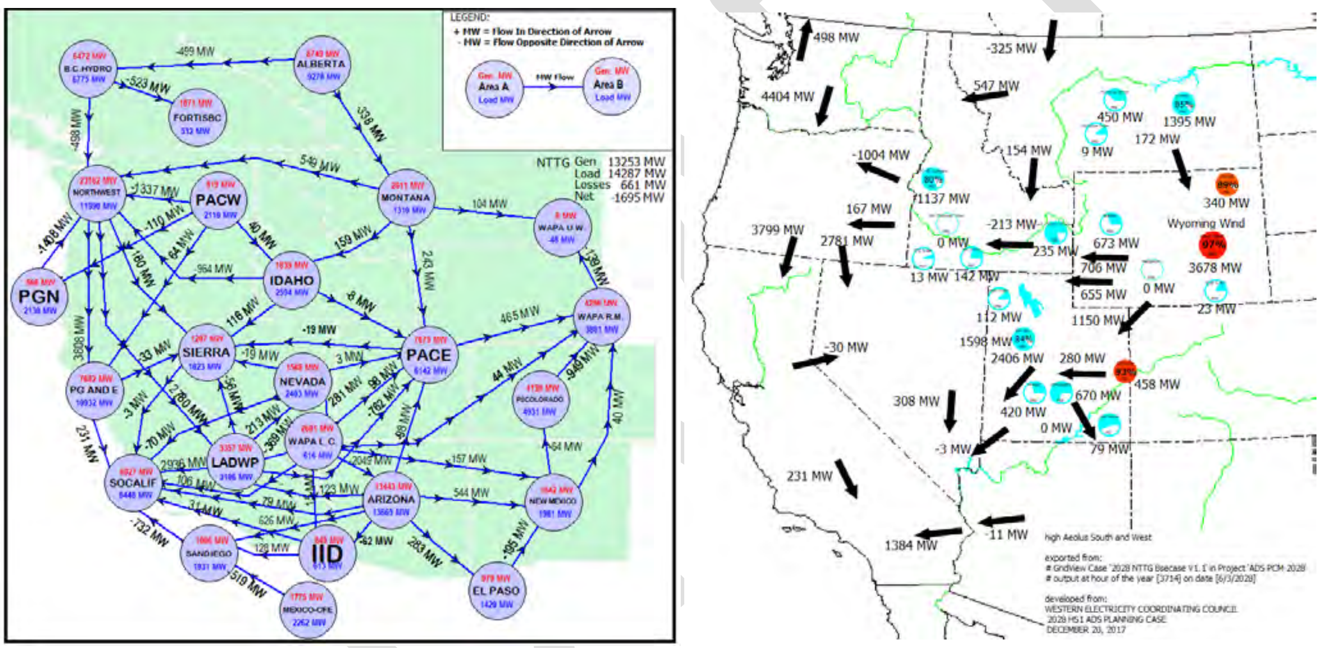
Case G Scenario 2 – High Borah West Case with Utah Wind Replacement Energy



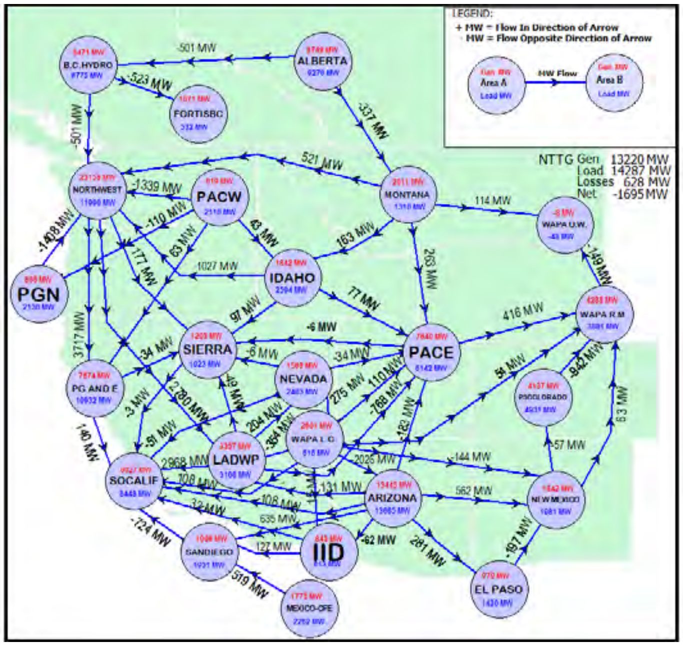
Case G Scenario 3 – High Borah West Case with Pacific Northwest Replacement Energy

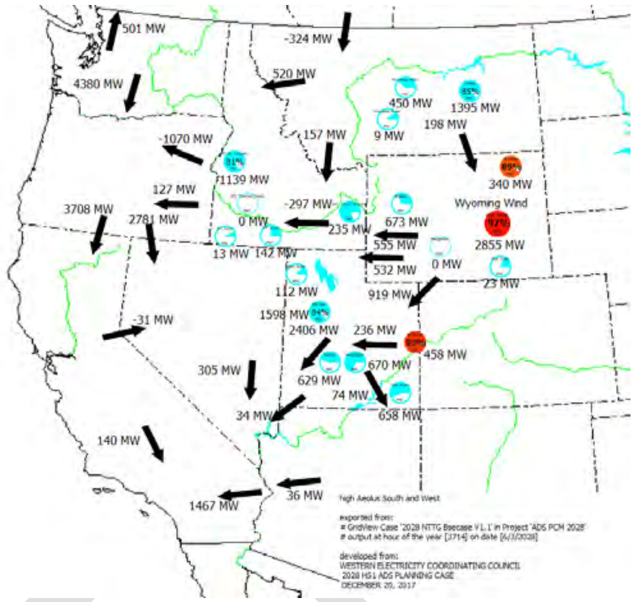


Case I Scenario 1 – High Aeolus West and South Case with Wyoming Wind Replacement Energy

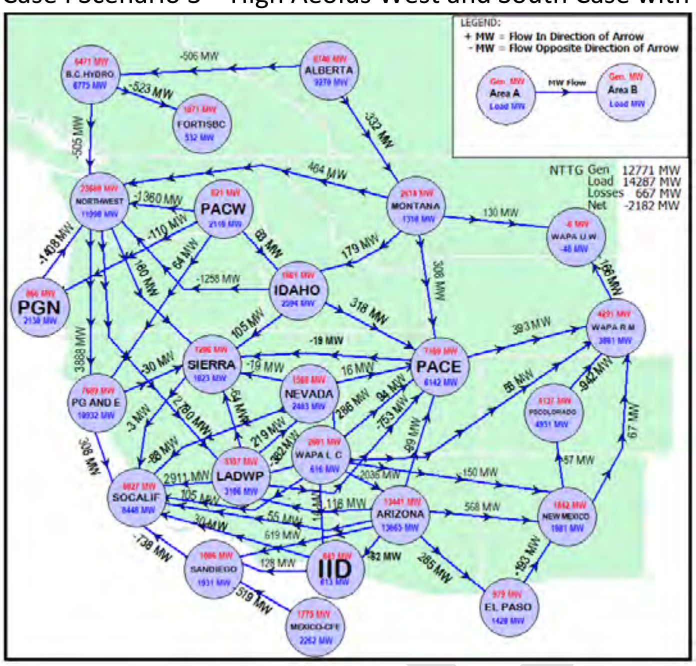


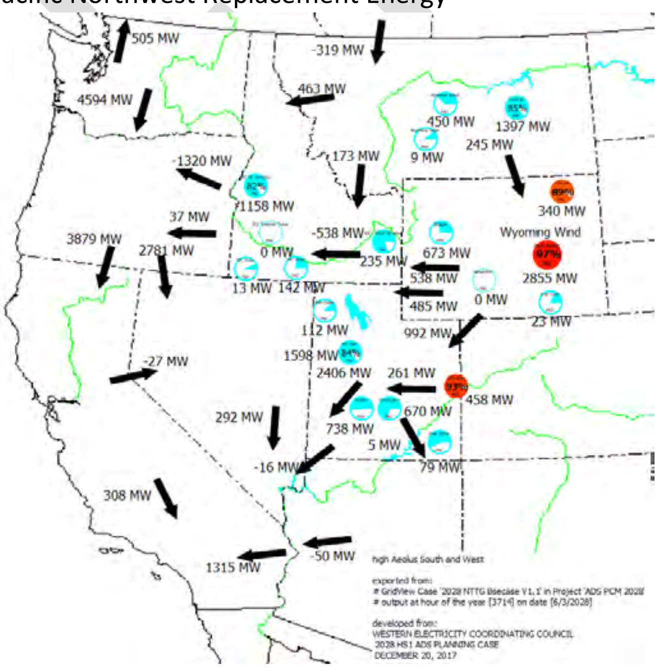
Case I Scenario 2 – High Aeolus West and South Case with Utah Wind Replacement Energy





Case I Scenario 3 – High Aeolus West and South Case with Pacific Northwest Replacement Energy





Appendix E Economic Study Request

NTTG 2019 Economic Study Request (ESR) Report

Executive Summary

The Technical Work Group (TWG) study, using stressed power flow (PF) cases for the NTTG footprint, showed acceptable performance covering the ESR scenario for year 2028 for all the relevant stressed condition cases that were used in development of the dRTP and demonstrated reduced capital costs, however, at the cost of added transmission congestion and dumped energy in Wyoming. The power flow portion of the study focused on the impacts serving loads in the Wasatch Front and did not address impacts serving other PacifiCorp network loads.

While the study demonstrated acceptable system performance, additional production cost model (PCM) simulations indicated that the proposed ESR 345 kV transmission had lower overall transmission capacity than the planned dRTP 500 kV transmission resulting in increased flows on transmission exiting Wyoming, including non-NTTG transmission and some generation dispatch decrease in Wyoming due to inadequate capacity. This capacity limitation forced generation to increase in Utah in the PCM simulations, dispatching it without consideration of economics.

In addition to the economic and capacity limitations, permits and right-of-way for the proposed 2-345 kV lines option on separate rights-of-way may be a concern assuming that an additional 12-15 years may be required for securing these rights and associated permits. In order to support PacifiCorp's customer needs, PacifiCorp is already in the process of building Aeolus to Anticline 500 kV transmission system in WY, scheduled for energization in 2020. In contrast, the proposed ESR 2-345kV option has no sponsor.

Background:

The NTTG Regional Economic Study Request window provides stakeholders with the opportunity to request NTTG to model the ability of specific upgrades or other investments to the Transmission System or Demand Resources, not otherwise considered in the Local Transmission Plans of the NTTG Transmission Providers, to reduce the overall cost of reliably serving the forecasted needs of the NTTG Footprint.

In Quarter 5 of the NTTG 2018-2019 Biennial Study cycle, Deseret Power on behalf of the "Joint Parties" (Utah Association of Energy Users, Deseret Power, Utah Municipal Power Agency, Utah Department of Commerce Office of Consumer Services and Utah Associated Municipal Power Systems) submitted an ESR to evaluate up to two 345 kV transmission lines as a lower cost alternative to Gateway West and Gateway South 500 kV transmission proposed in the draft Regional Transmission Plan (dRTP).

Joint Partiers Economic Study Request:

The Joint Parties request that a lower cost transmission alternative be studied, that reliably meets the projected 2028 loads and resources submitted by NTTG members for the NTTG footprint. With wind resource additions projected to cause transmission constraints in the Wyoming area, it is requested that a more targeted transmission solution consisting of 345 kV transmission line additions through the immediate congestion area be developed and evaluated as a lower cost alternative to Gateway West and Gateway South. Targeting the transmission additions through the congestion area and utilizing the existing 345 kV system voltage class (rather than introducing a higher cost 500 kV solution) may result in fewer transmission miles at a lower cost per mile when compared to the dFRTP.

This study request consists of evaluating up to two 345 kV transmission lines, independently originating in a logical location on the east side of the transmission constraint such as the Windstar or Aeolus area of Wyoming and independently terminating at a logical location on the west side of the constraint such as Bridger, Borah or Midpoint as needed to meet reliability criteria. Please identify the minimum amount of 345 kV line additions between these locations that are required to meet reliability criteria, including the use of any transformer additions that may be necessary.

It is also requested that this potential lower cost transmission alternative be evaluated under the scenarios that were studied as part of the Public Policy Considerations request, where additional resources are expected to be retired in the Wyoming area.

Link to the 2019-Q5 ESR: Joint Parties Economic Study Request

The Economic Study (ESR) assumed initially:

1. Two 345 kV circuits[35] between Aeolus and Anticline[36] (154 Miles),
2. A single 345 kV circuit from Anticline to Bridger
3. Two series compensated[37] 345 kV circuits between Anticline and Populus (203 Miles),
4. A single series compensated 345 kV circuit between Populus and Midpoint (153 Miles),
5. A single series compensated 345 kV circuit between Midpoint and Hemingway (130 miles),
6. With two Hemingway 345/500 kV transformers (700 MVA each).
7. Line shunt reactors to balance 90% the line charging of each circuit and bus shunt reactors for the remaining 10%.

Discussion

The Economic Study Request references the existing 345 kV system voltage class that already exists in Wyoming, hence, making the case that there is no need (yet) – to introduce higher cost 500 kV

[35] Assuming a bundled 1272 kcm H-frame construction.

[36] An alternate will consider using the Gateway West line at 500 kV already under construction and add second 345 kV.

[37] Compensation set to match the existing Bridger-Populus 345 kV lines.

solution. To clarify, there is no existing 345 kV transmission east of Bridger in eastern Wyoming in the area of significant congestion.

The study tested the ESR configuration on all eight NTTG cases (A, B, C, E, F, G, H, I). Particular attention was focused on the Path C constraint, as mentioned above, the lack of the Aeolus to Clover 500 kV line segment support caused increased stress across Path C. Additional analysis of the Path C constraint was found to be necessary.

The study performed the same contingencies as performed in the dRTP analysis, with additional contingencies added to the ESR configuration facilities. Additional N-2 outages were evaluated on the ESR facilities to determine which N-2 outages should be categorically avoided.

Power Flow Analysis

Performance of the ESR configuration was comparable in most of the NTTG cases with the exception of Case I which stressed Path C to its transfer capability.

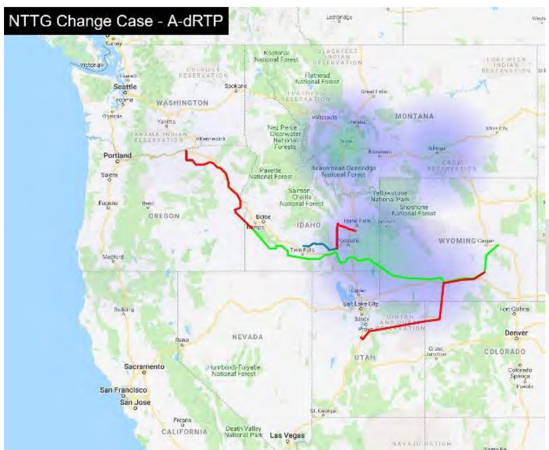


Figure 71 – Heavy Summer Case with dRTP configuration

Figure 72 – Heavy Summer Case with ESR configuration

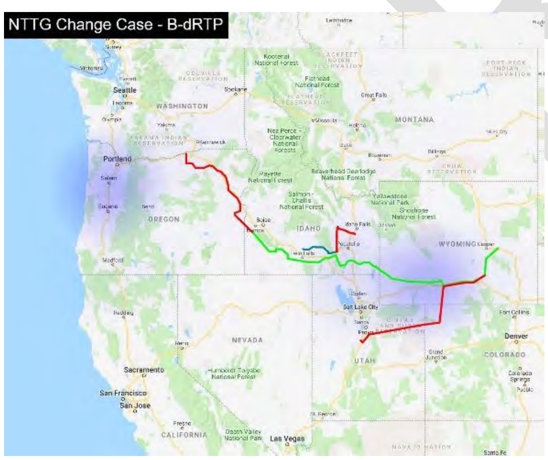


Figure 73 – Heavy Winter Case with dRTP configuration

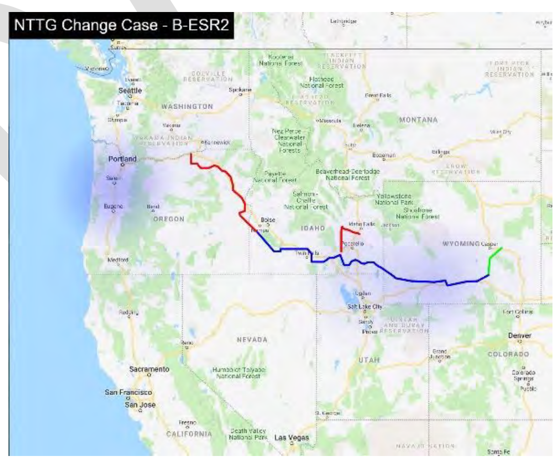


Figure 74 – Heavy Winter Case with ESR configuration

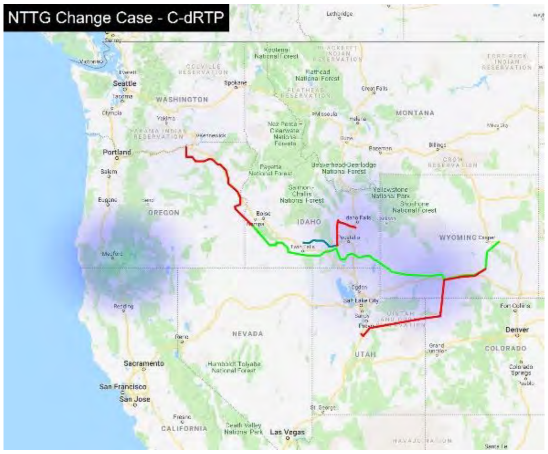


Figure 75 – High NW-ID Import Case with dRTP configuration

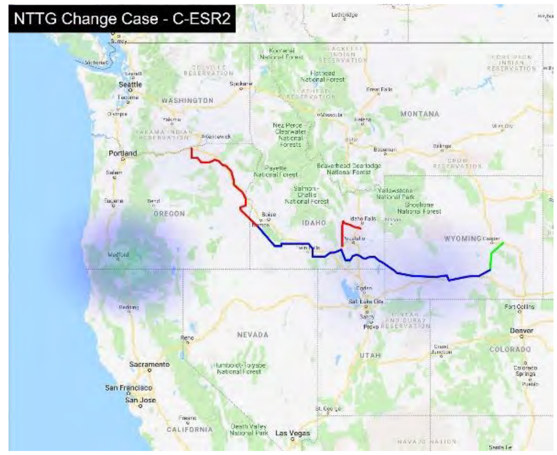


Figure 76 – High NW-ID Import Case with ESR configuration

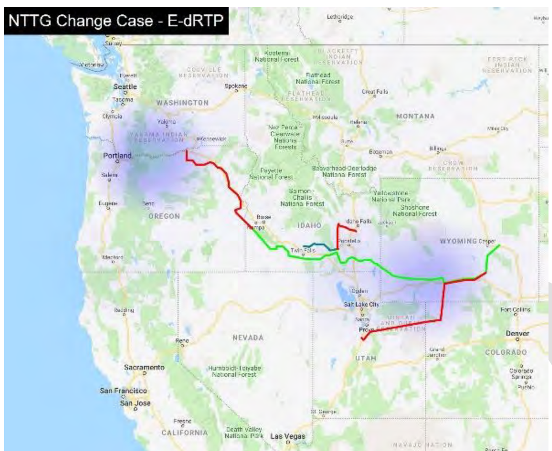


Figure 77 – High Tot2/COI Case with dRTP configuration

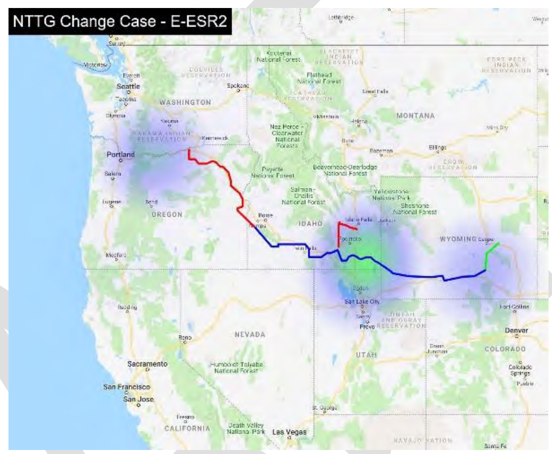


Figure 78 – High Tot2/COI Case with ESR configuration

The highlighted violations in the ESR configuration are the result of slight post contingency overloads in the 138 kV Path C system.

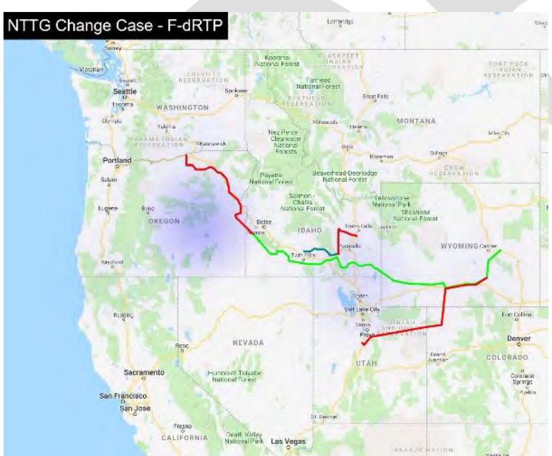


Figure 79 – High Wyo Wind Case with dRTP configuration

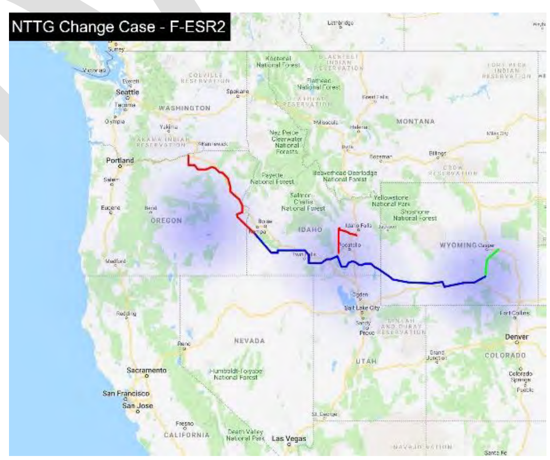


Figure 80 – High Wyo Wind Case with ESR configuration

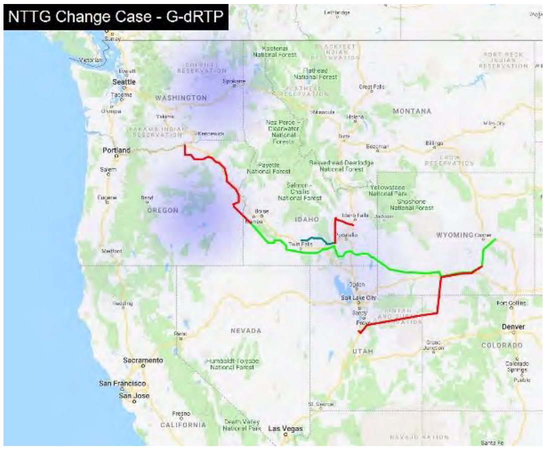


Figure 81 – High Borah West Case with dRTP configuration

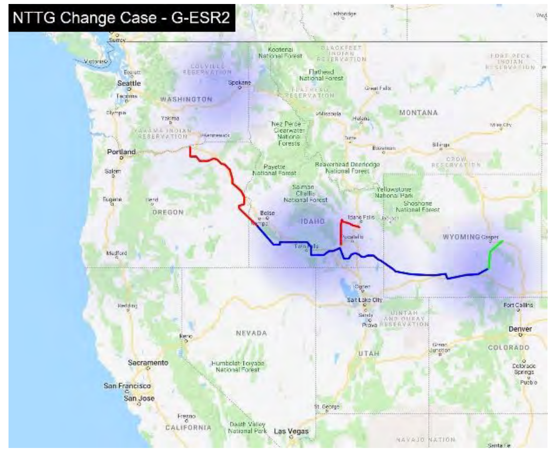


Figure 82 – High Borah West Case with ESR configuration

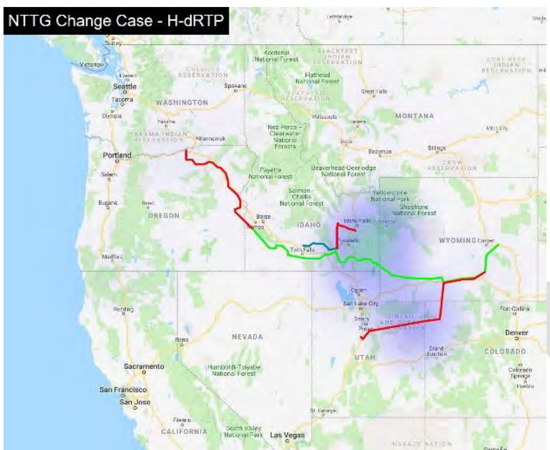


Figure 83 – High NTTG Import Case with dRTP configuration

Figure 84 – High NTTG import Case with ESR configuration

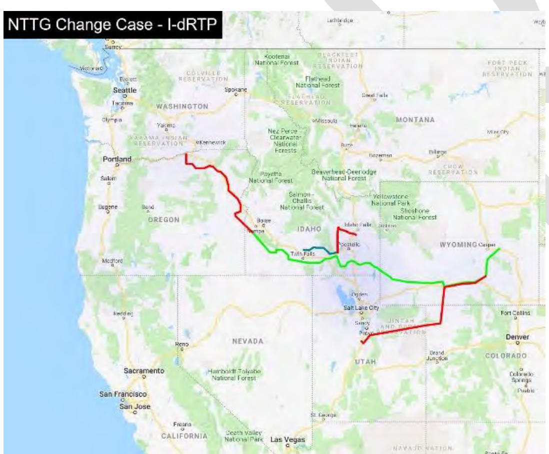


Figure 85 – High Aeolus West/South Case with dRTP configuration

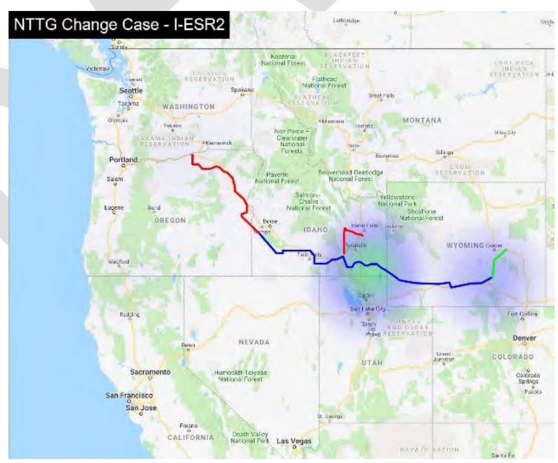


Figure 86 – Heavy Aeolus West/South Case with ESR configuration

The absence of the Aeolus – Clover 500 kV line connection to Utah resulted in increased flows across Path C up to the 2250 MW path capability. The highlighted violations in the ESR configuration are the result of post contingency overloads in the 138 kV Path C system similar to those that occur in Case E.

Production Cost Analysis

To determine the full costs from transmission expansion, consideration should also be given to system operating costs, annual electricity costs developed using production cost modeling (PCM). These costs, should then be added to the capital and or fixed costs for the resource and transmission added.

Using the WECC 2028 ADS PCM case, a PCM run was made comparing the two scenarios (dRTP and ESR, see Figure 17) hourly flows that result in increased incremental loading on Path C by 700 MW and up to 1000 MW (see Figure 18) for some hours and adds flow for select hours on other interconnected paths to Wyoming, loading through Montana north and to the northwest (paths 8, 18), including the COI\PDCI and on the east side, connections to WAPA and through Colorado on TOT 3 + TOT 5 and south as indicated in the charts below. With the dRTP, Path C flows occasionally exceeded 2000 MW and in the ESR configuration, Path C flow hits the 2250 MW path limit more often, causing a change in the economic dispatch.

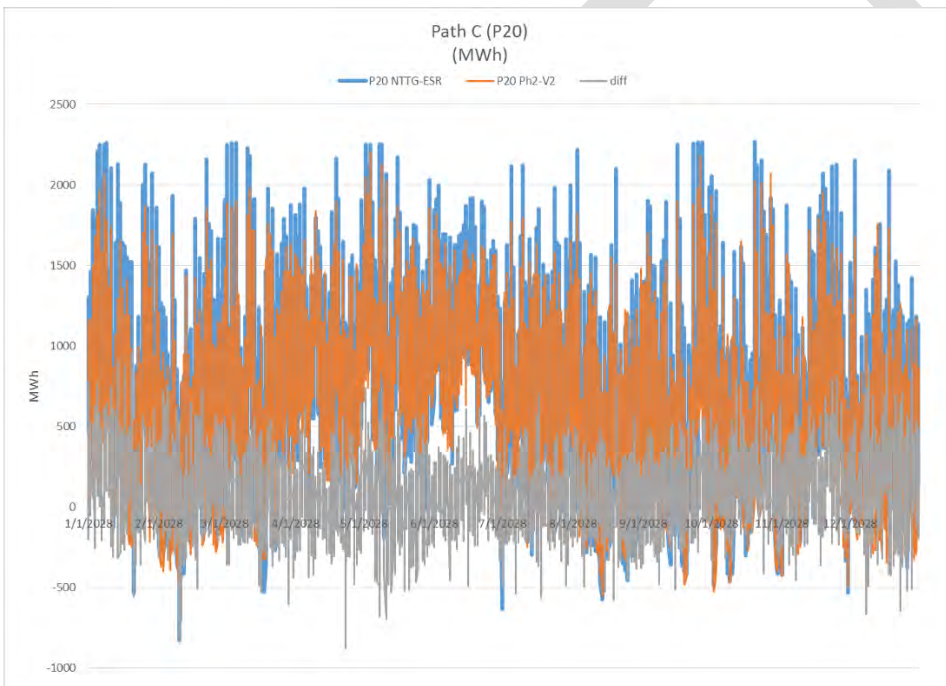


Figure 87 – PCM case Path C flows

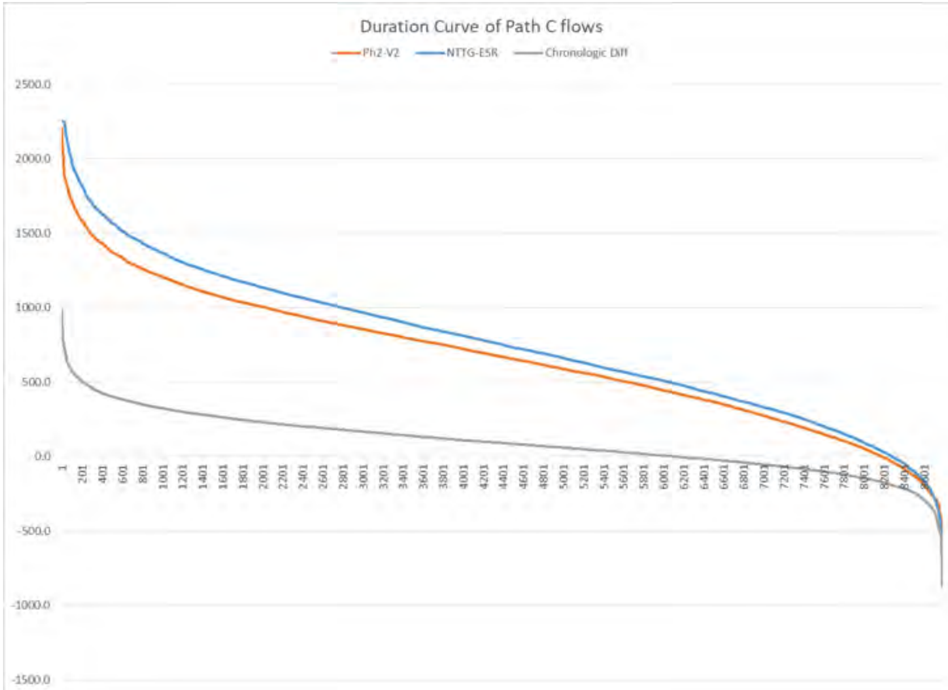


Figure 88 – Duration Curve of Path C flows[38]

Checking the other transmission ties connecting to Utah indicates resources south of Utah only contribute somewhat to the Aeolus to Clover 500 kV line removal, indicating that Path C limitations are resulting in increased flows through Colorado as well as increased Utah area generation dispatch.

[38] The Blue and Orange curves are non-coincident sorts of the Path C flow of the two cases. The Gray curve has taken the flow difference between the two cases for each hour and sorted that result.

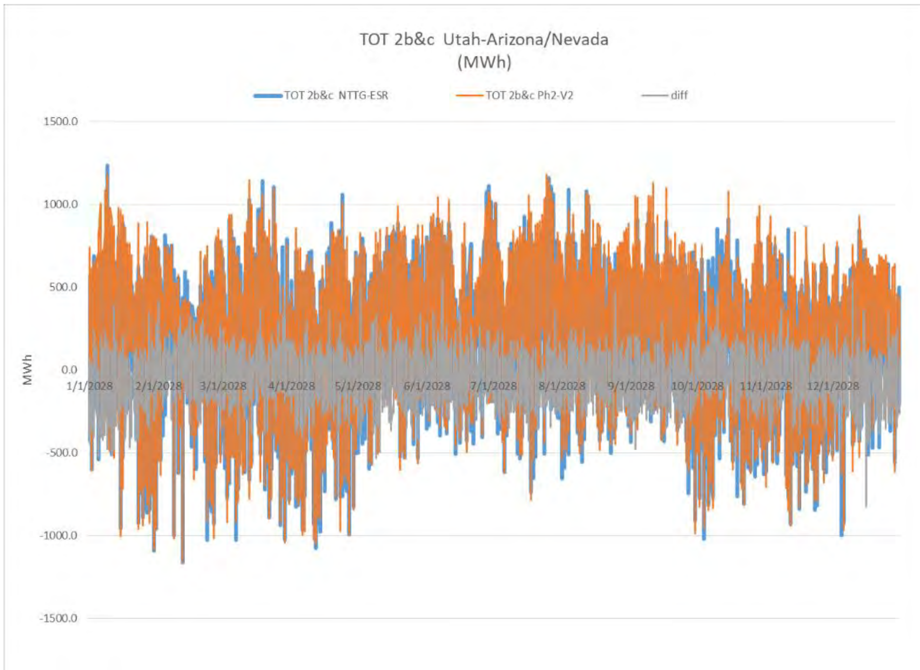


Figure 89 – PCM case Tot 2 b&c flows

The increased power flows through Colorado across the Tot 1a path are shown in Figure 90. Flows west of Bonanza can be seen to increase demonstrating that system flow increases through Colorado and Eastern Utah in the ESR configuration when compared to the dRTP, as shown in Figure 91.

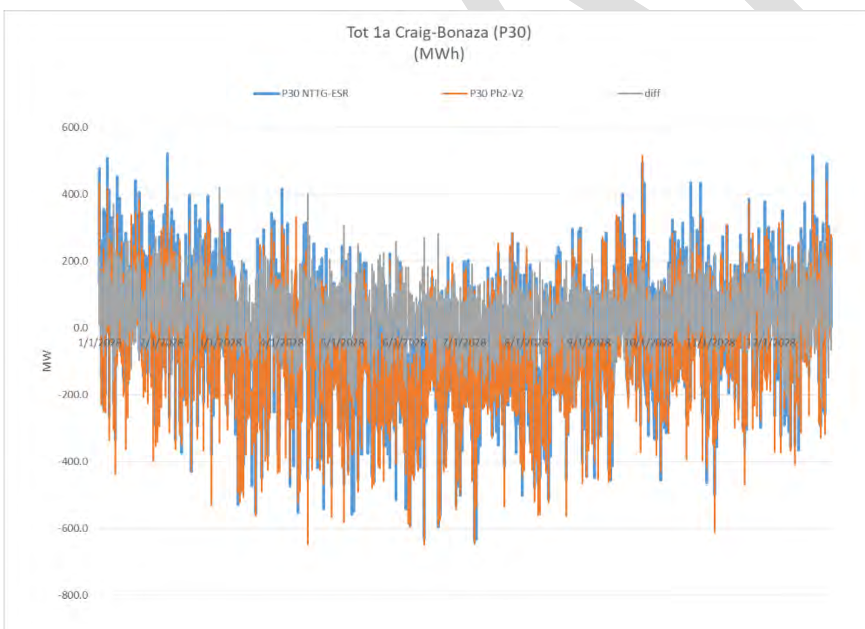


Figure 90 – PCM case Tot 1a flows

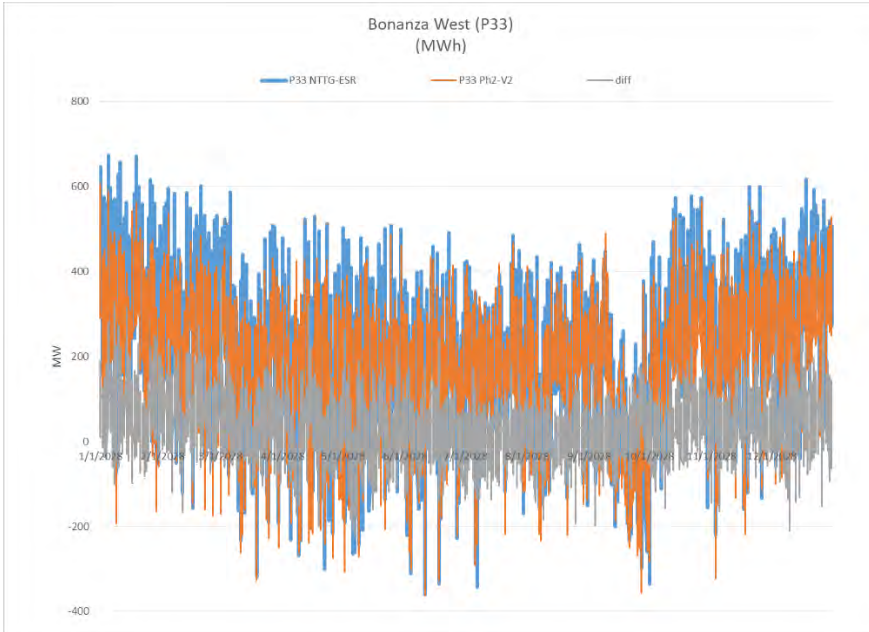


Figure 91 – PCM case West of Bonanza flows

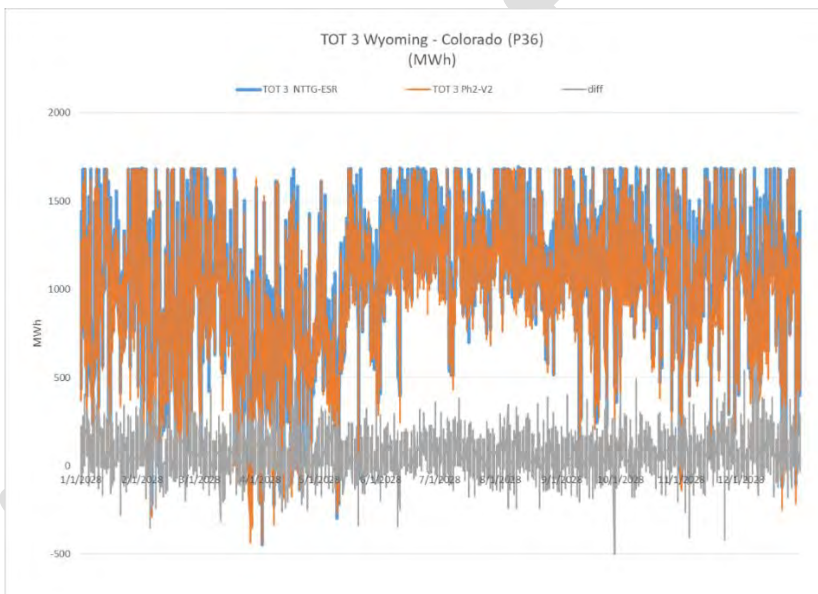


Figure 92 – PCM case Tot 3 Wyoming-Colorado flows

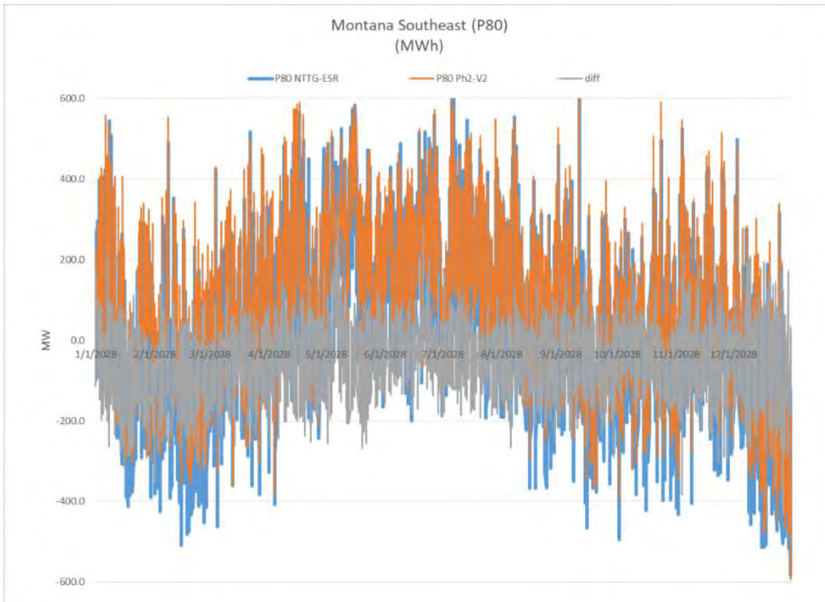


Figure 93 – PCM case Montana Southeast flows[39]

Checking paths with increased congestion costs, the PCM results indicate that resources in Wyoming are subject to increased congestion. Most significantly, congestion costs almost double in the ESR configuration on the ties into Colorado from Dave Johnston when compared to the already congested amount in the dRTP configuration. Similarly, flows also increase to the north into Montana and across to the Pacific Northwest, continuing south on PDCI.

[39] Note Montana Southeast path direction southbound, increased flows north out of Wyoming will be shown as a negative flow.

Total Congestion Cost ($)	dRTP	ESR	diff
P08 Montana to Northwest	498,056	932,607	434,552
P18 Montana-Idaho	14,890	28,654	13,764
P20 Path C	-	568,026	568,026
P32 Pavant-Gonder InterMtn-Gonder 230 kV	2,524,955	2,936,094	411,139
P36 TOT 3	3,920,847	6,860,597	2,939,750
P39 TOT 5	-	142,631	142,631
P65 Pacific DC Intertie (PDCI)	-	145,014	145,014
P66 COI	10,672	3,412	(7,260)
P75 Hemingway-Summer Lake	6,622,456	5,821,117	(801,339)
P80 Montana Southeast	47,212	210,098	162,886
P83 Montana Alberta Tie Line	49,338,336	53,604,504	4,266,168
South of Custer	2,409,188	3,745,993	1,336,805
W27_BS_PACE__RM_WACM_1	9,430,535	10,050,967	620,432
W17_NW_NWMT+__RM_WACM_1	2,119,987	2,243,588	123,602
Total			10,356,169

Table 50 – Selected PCM case NTTG ties increased Congestion costs

The total change in PCM dispatch costs for the NTTG footprint is shown in Table 51 below. It should be noted that fixed dispatch and hydro resources are not included in this tabulation, as those resources are included at zero cost in the PCM model.

Operating Costs (2018$)	***2028ADS_Ph2-V2.0 dRTP***	***2028ADS_Ph2-V2 ESR***	***Diff (ESR-dRTP)***
IPFE	$13,311,231	$13,078,921	$(232,310)
IPMV	$38,234,276	$37,798,816	$(435,460)
IPTV	$127,704,080	$130,410,392	$2,706,312
NWMT	$81,126,576	$82,660,440	$1,533,864
PACW	$339,970,528	$340,844,736	$874,208
PAID	$70,948,592	$70,958,600	$10,008
PAUT	$617,476,672	$624,573,312	$7,096,640
PAWY	$102,819,872	$101,039,432	$(1,780,440)
PGE	$238,849,920	$246,217,840	$7,367,920
NTTG Total	**$1,630,441,747**	**$1,647,582,489**	**$17,140,742**

Table 51 – Change in NTTG thermal operating Costs between dRTP and ESR cases

Changes in the network flows resulting from the ESR configuration cause increased dump energy in the NTTG footprint as shown in Table 3.**Error! Reference source not found.**.

Table 52 – Change in NTTG dump energy between dRTP and ESR cases

Accounting for the increased transmission flows entering\exiting PACE as a result of the ESR decreased transmission capacity is warranted. Although within their transmission ratings, PacifiCorp has no existing firm contractual arrangements on transmission lines\paths listed in the Table 53 to serve

PacifiCorp network loads. Consistent with operating practices, PacifiCorp would drop "bottled" energy[40] and limit congestion as necessary in pursuit of the economic dispatch. Hence, the aggregate energy summarized on transmission lines\paths below were used to calculate what could be characterized as "bottled energy" cost; this is essentially the PacifiCorp energy not finding its way out plus the non-contracted flows circulating to serve PacifiCorp's network loads.

(MWh)	P08 MT-NW	Tot 2 (2b1+2b2 +2c)	P32 Pavant-Gonder	P28, IPP-Mona	P36, Tot 3	P30, Tot 1A	Wyo Spill	Total
Bottled Energy	939,192	241,702	80,679	634,505	694,360	472,876	21,381	3,084,695

Table 53 – *Bottled Energy, connecting to PACE and PACW power system*

Calculating the Annual Bottled Energy Costs (assuming a $23.13/MWh Utah Average clearing cost from the PCM model):

3,084,695 MWh x $23.13/MWh = $71.3 million

P-V & Q-V analysis

Considering that a large portion of the Utah generation south of Path C is from coal (over 2900 MW) and assuming that those coal resources will be retiring beyond the 10 year study timeframe, it is possible that the Utah system will see increased constraints with the ESR configuration compared to the dRTP. Replacing those coal resources with renewable wind and solar resources will likely be the preference. While there are proven solar resource opportunities in southern Utah, access to the Wyoming wind resources or resources north of Path C will be limited, forcing selections elsewhere. The ESR configuration could result in dispatch changes with increased must run resources within the state of Utah, potentially adding yearly cost to the overall cost of the transmission upgrades proposed in the ESR.

Other paths including COI, PDCI and the AB32 also exhibit increased congestion costs indicating that the dRTP provides benefit outside the NTTG Footprint compared to the ESR configuration.

While the ESR configuration showed acceptable performance in the selected power flow hours considered, the overall capability of the ESR configuration is less than the dRTP. For example, outages in the Wyoming 345 kV segments for some of the stressed condition scenarios resulted in the remaining system to be at its thermal capacity, indicating the ESR configuration is at its

[40] The term "Bottled Energy" is use to represent the additional energy crossing the transmission network that would require additional firm transmission rights and is assumed to not likely available. Without those transmission rights, the energy would have to be dumped.

capability while the 500 kV dRTP configuration[41] has further capability beyond the conditions studied.

Power vs Voltage (P-V) and Var vs Voltage (Q-V) analysis was performed on Case I which had Path C loaded to 2214 MW in the ESR configuration. The Q-V analysis shown in Figure 94 confirms that at the flow levels in the ESR Case I, there is adequate reactive margin for the critical N-2 contingencies. The P-V analysis shown in Figure 95 suggests that the ESR configuration is significantly less capable of servicing future Utah loads. Voltages of the dRTP configuration with an additional 1200 MW schedule exceed that of the ESR configuration with only a 400 MW additional schedule.

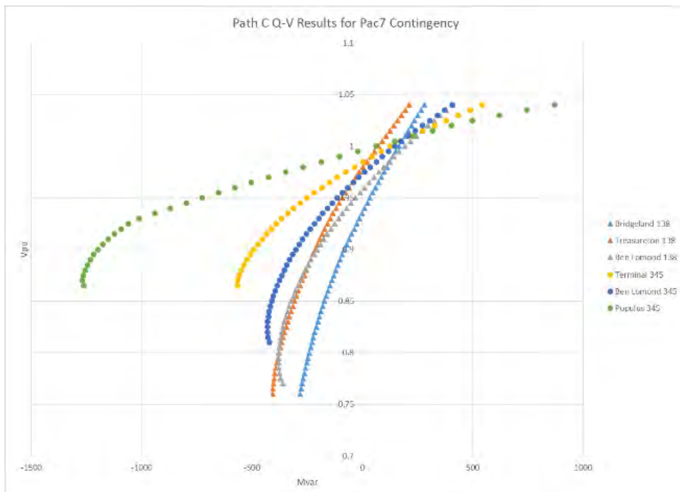


Figure 94 – Q-V curves for ESR2 configuration on Case I

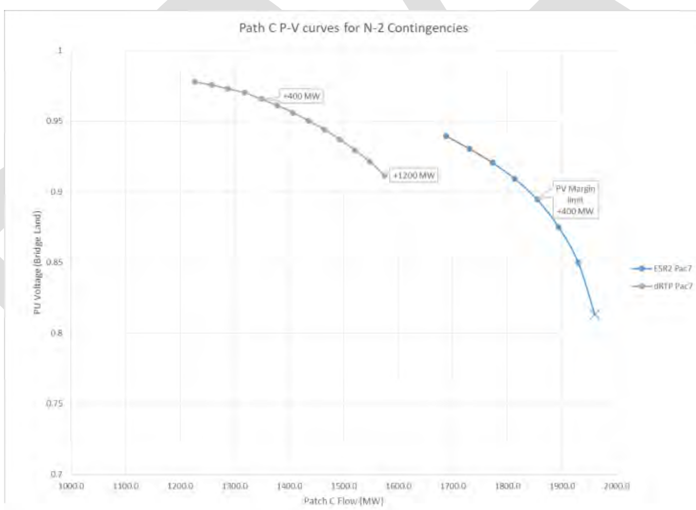


Figure 95 – P-V curve for dRTP and ESR2 configurations on Case I

[41] Due to the increased operating voltage and an additional conductor necessary to mitigate radio noise and corona issues operating at 500 kV.

To mitigate Path C overload concerns, an additional 345 kV circuit between Populus and Terminal was contemplated, however, transmission corridor restrictions around Willard Bay, north of Ogden, Utah likely will prohibit its construction (see further discussion of the corridor in Attachment B), effectively limiting the Path C cut-plane to 2250 MW for the foreseeable future.

Public Policy Consideration (PPC) Sensitivity

A sensitivity run with the PPC resource scenarios (additional wind in Wyoming replacing retired coal units at Bridger and Naughton, Utah Wind and Pacific Northwest) and only one 345 kV circuit between Anticline and Populus, found that the Path C constraint becomes more stressed with increased Path C overloads and low voltages than the dRTP configuration.

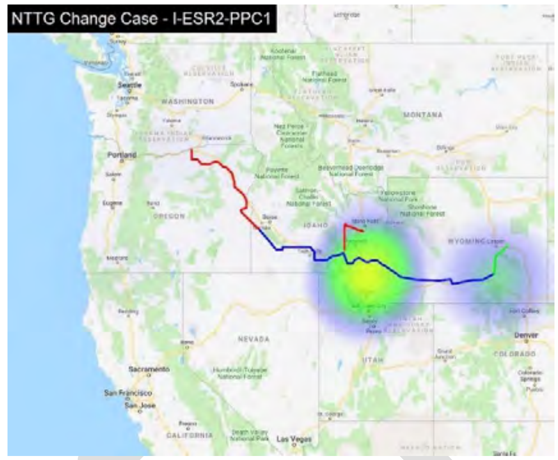


Figure 96 and 27 – PPC Scenario 1 (Wyo Wind) applied to Case I dRTP/ESR configurations

Figure 28 and 29 – PPC Scenario 2 (Utah Wind) and Scenario 3 (Northwest) applied to Case I

The ESR N-2 contingencies indicated that loss of both Aeolus to Anticline circuits should be avoided. Loss of both circuits would likely lead to cascading performance. Separate ROWs would be required to consider this contingency not credible.

Cost & Benefit Analysis

Capital Cost of the final configuration including the facilities listed at the top of page two, was calculated to be $2,601,920,914 compared to $4,525,329,044 for the Gateway West and South portions of the dRTP configuration[42].

Segment	*Miles*	*Cost/mile*	*Cost*
Wyoming 230 kV Line Segments	*147*	*981,246*	*144,635,610*
Aeolus – Anticline #1	*154*	*2,154,692*	*331,844,061*
Aeolus – Anticline #2	*154*	*2,154,692*	*331,844,061*
Anticline – Bridger	*5*	*2,127,863*	*10,639,314*
Anticline – Populus #1[43]	*203*	*2,358,823*	*478,841,071*
Anticline – Populus #2	*203*	*2,358,823*	*478,841,070*
Populus – Midpoint	*152*	*2,292,848*	*348,512,922*
Midpoint – Hemingway	*126*	*2,001,499*	*263,197,134*
Total	*794*		*2,388,355,243*

Table 54 – Capital Cost Summary of ESR Configuration Transmission Lines

Substation	*Cost*
Windstar, DJ, Heward 230 kV	*20,369,890*
Aeolus	*52,848,571*
Anticline	*24,596,296*
Bridger	*4,364,976*
Populus	*44,438,329*
Midpoint	*19,759,439*
Hemingway	*47,188,170*
Total	*213,565,671*

Table 55 – Capital Cost Summary of ESR Configuration Substation Additions

[42] Includes 230 kV Wyoming improvements and excludes B2H Project capital costs. If the two Anticline to Populus circuits were built on a double circuit structure, the total cost is estimated to be $2,410,453,404.

[43] If Anticline to Populus was built as a double circuit, the segment would cost $766,214,631 at $3,774,456 per mile. For the conditions studied, a double circuit performed acceptably, however, a double circuit configuration by its very nature has less capability than a two independent circuit configuration.

Using the NTTG levelized annual Cost calculator[44], the ESR configuration would result in an annualized construction cost savings of $270,502,236.

Due to the change in dispatch, a loss change comparison is less than intuitive, NTTG footprint losses actually drop slightly as shown in Table 56, due to increased local generation dispatch in response to congested paths.

Scenarios	2028 ADS PCM Ph2 - V2			2028 ADS PCM Ph2-V2_NTTG-ESR		
Area	Total Generation (MWh)	Served Load Includes Losses (MWh)	Estimated Losses (MWh)	Total Generation (MWh)	Served Load Includes Losses (MWh)	Estimated Losses (MWh)
IPFE	1,306,997	2,643,038	61,726	1,294,316	2,643,030	61,381
IPMV	4,259,555	5,729,208	141,942	4,239,286	5,729,188	141,148
IPTV	11,982,161	11,895,701	340,477	12,053,989	11,895,633	338,571
NWMT	12,917,237	12,059,774	86,939	12,976,891	12,059,701	86,452
PACW	20,473,372	22,034,952	545,501	20,444,353	22,034,861	542,447
PAID	6,866,373	6,331,344	133,686	6,867,434	6,331,320	132,939
PAUT	32,795,381	35,788,920	925,570	33,073,996	35,788,699	920,391
PAWY	17,305,782	10,754,518	214,625	17,201,309	10,754,504	213,424
PGE	15,758,254	21,852,634	616,719	16,025,738	21,852,494	613,268
NTTG Total	*123,665,112*	*129,090,089*	*3,067,183*	*124,177,311*	*129,089,430*	*3,050,020*

Table 56 – MWh Change in Generation, Load and Losses
between the dRTP and ESR configurations

Conclusion

An annualized cost savings of $270,502,236 is estimated by the ESR configuration compared to the dRTP configuration. At the same time an additional cost of $88,440,000[45] can be incurred as the variable generation operating and maintenance (VO&M) cost in the ESR as compared to the dRTP. Additional consideration, however, should be given to other factors, such as:

1. PCM simulations indicate additional power flow stresses for select hours on various paths within the Western Interconnect, and more so to immediate transmission connected to the NTTG footprint.

2. Lower cost of dumped energy from Wyoming wind that is replaced by higher cost increased energy, using thermal resources in Idaho and Utah (assuming no additional solar or wind resources in Utah).

[44] The NTTG Annualized cost calculator uses a 40 Year economic life for the facilities, 2.5% fixed O&M cost rate with a 2.5% O&M cost escalator, 1% property tax and 0.5% for insurance in the ongoing cost calculation. Financing Costs assume a 50/50 split between equity and debt with a debt rate of 6.0% and the cost of equity at 11%, resulting in a 8.5% weighted cost of capital. Financing costs of PacifiCorp are not reflected in these assumptions.

[45] $71,300,00 in bottled energy and $17,140,000 in increased VO&M costs

3. Some resources may have to be designated as must-run resources in order to reliably serve the load for select hours of the year based on PCM simulations and assuming no additional Path C facilities.

4. The 500 kV design provides additional system robustness and reduces stress across Path C.

Gateway West and Gateway South 500 kV transmission lines have established transmission capability through a rigorous Western Electricity Coordinating Council's Path Rating Process. The transmission upgrades proposed in the ESR do not have an established transmission capability. The backup support provided by Gateway South cannot be achieved with the 345 kV circuit configuration. Ultimately, the 345 kV transmission option does not provide the full support expected from Gateway West and South 500 kV lines.

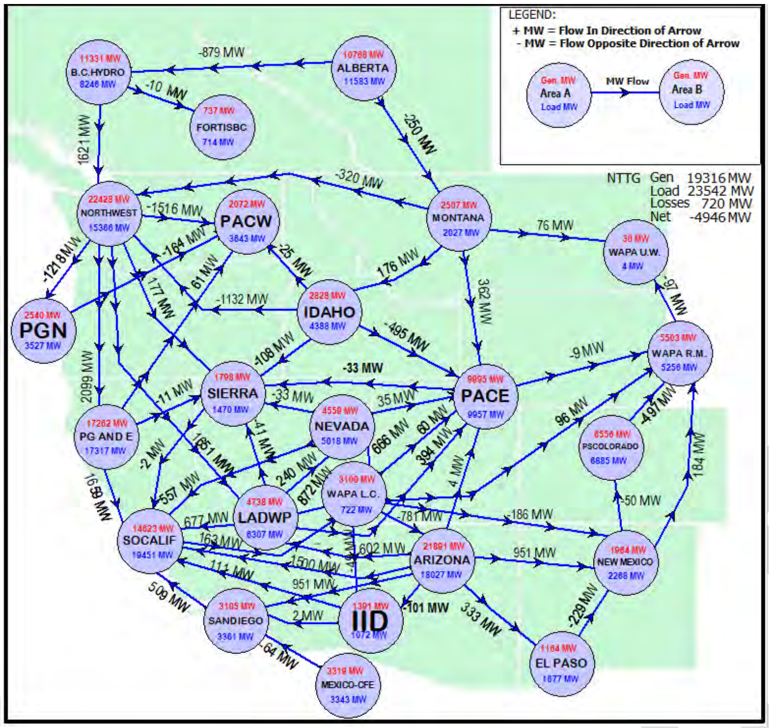
Many assumptions have been made that this ESR configuration would be constructible by 2028. It has taken since the early 2010's, to establish the necessary permits to allow construction of the many segments of the Gateway Projects. The first Gateway West segment is planned to be in-service in 2020. In some cases, acquiring the necessary permits for this ESR configuration could take another 12 to 15 years.

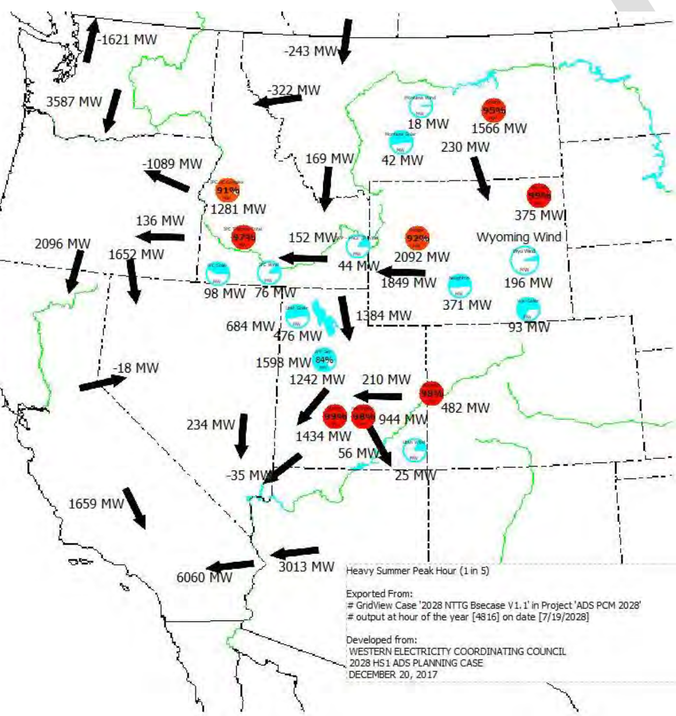
This ESR configuration has been only cursorily reviewed and considered the performance under 1 in 2 typical conditions. Many additional studies would need to be performed studying the normal boundary conditions considered in transmission planning studies.

Attachment – A

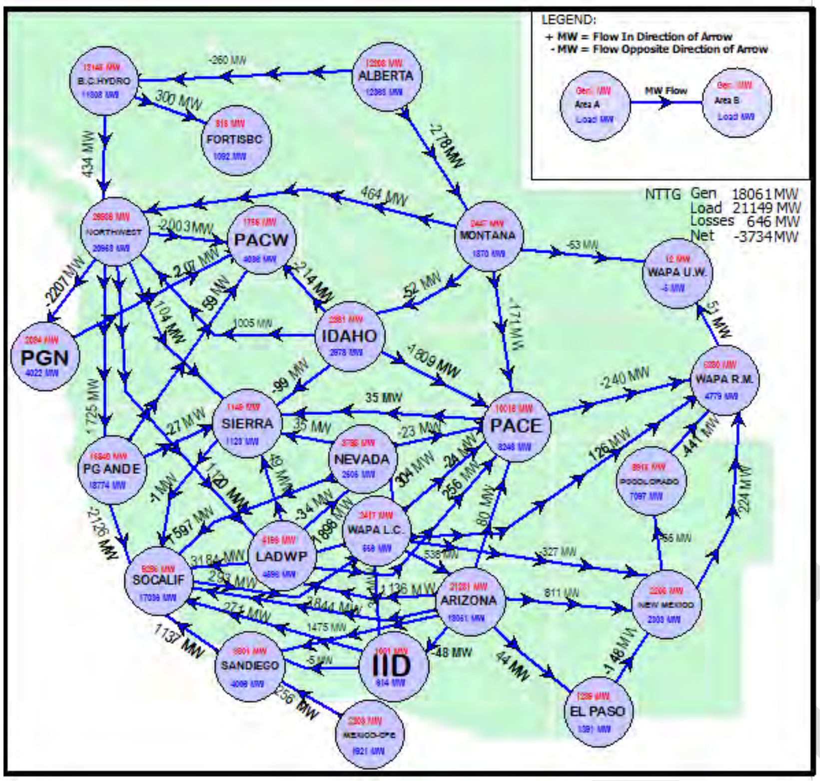
Revised Powerflow Cases

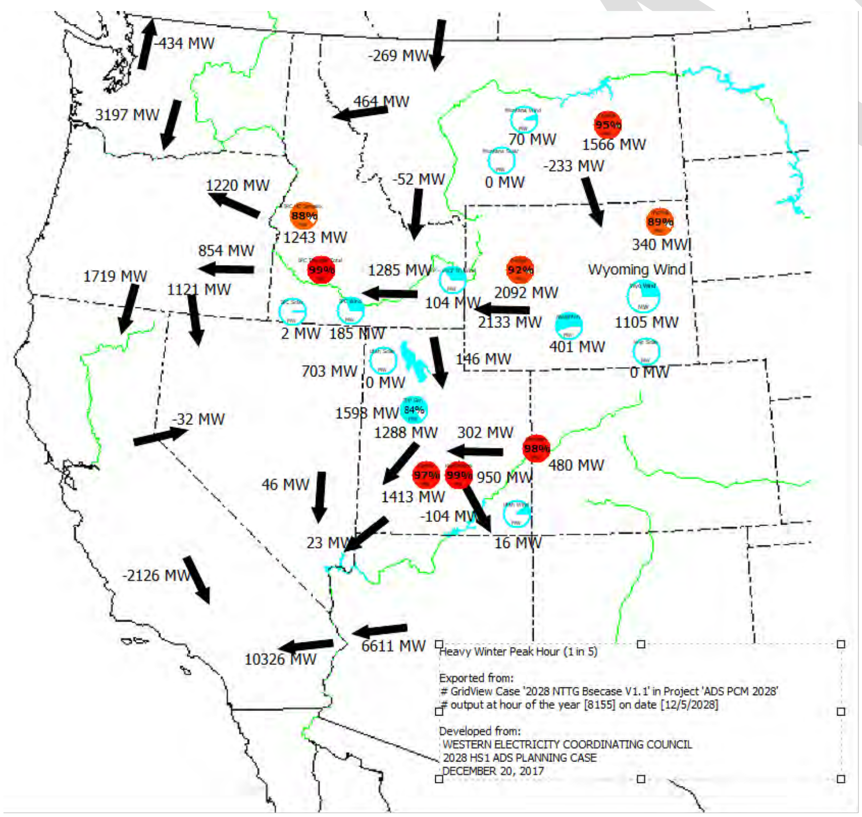
Case A – Heavy Summer



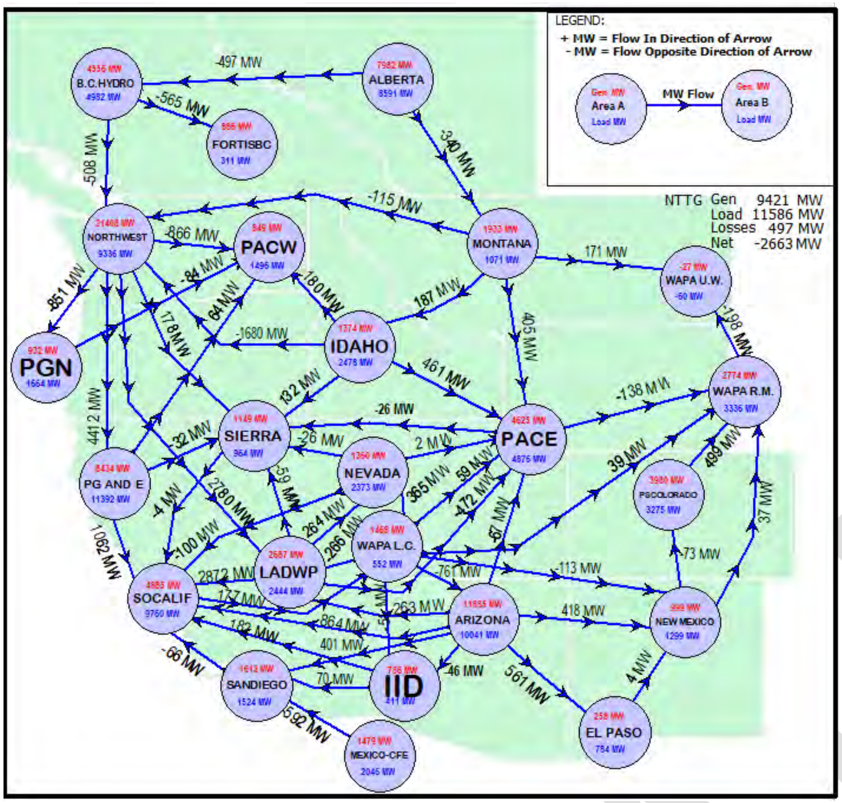


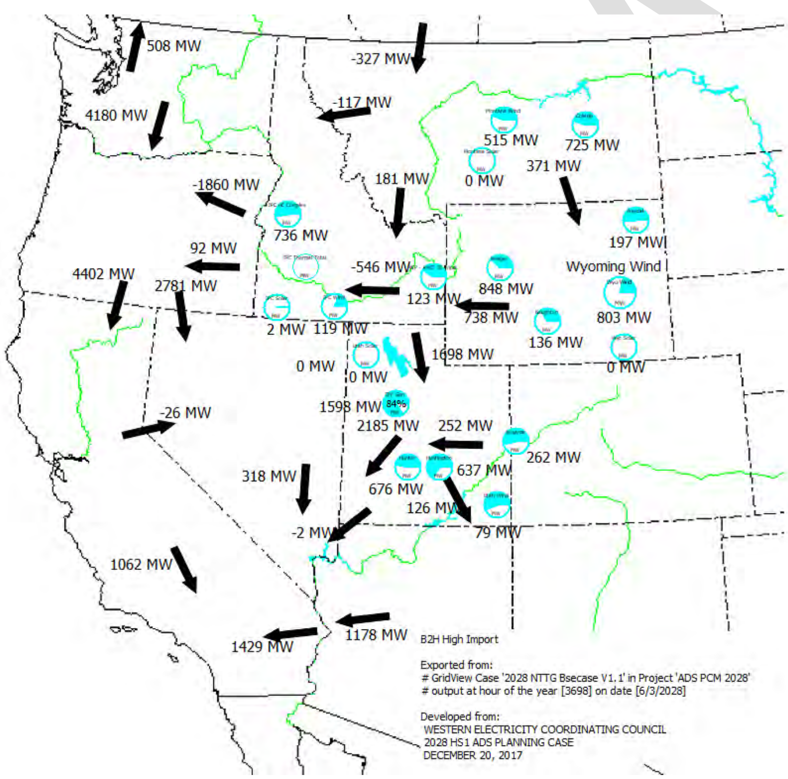
Case B – Heavy Winter



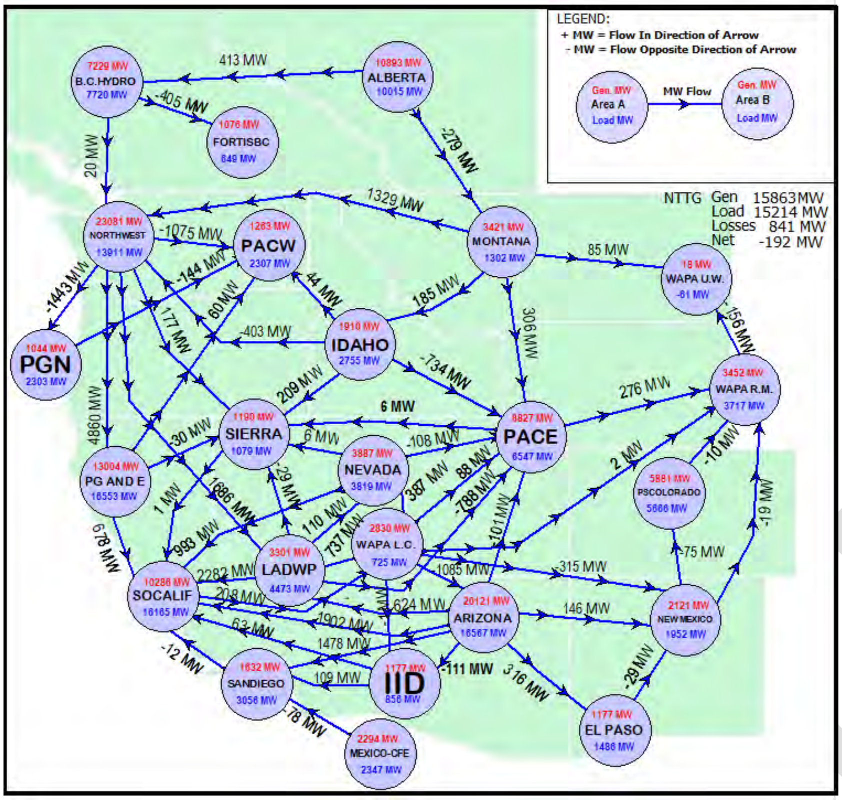


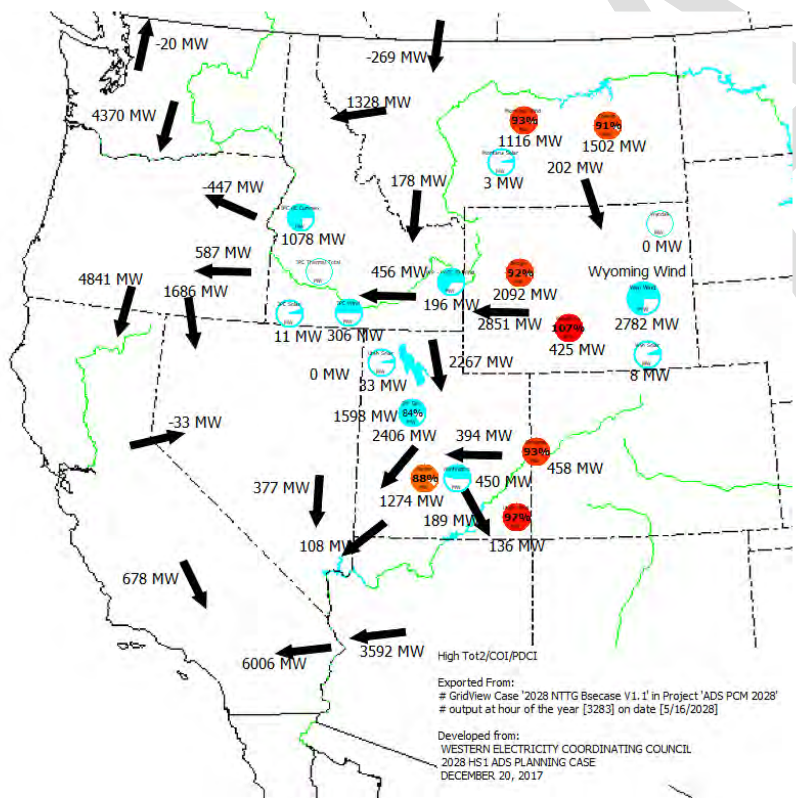
Case C – High ID-NW Import



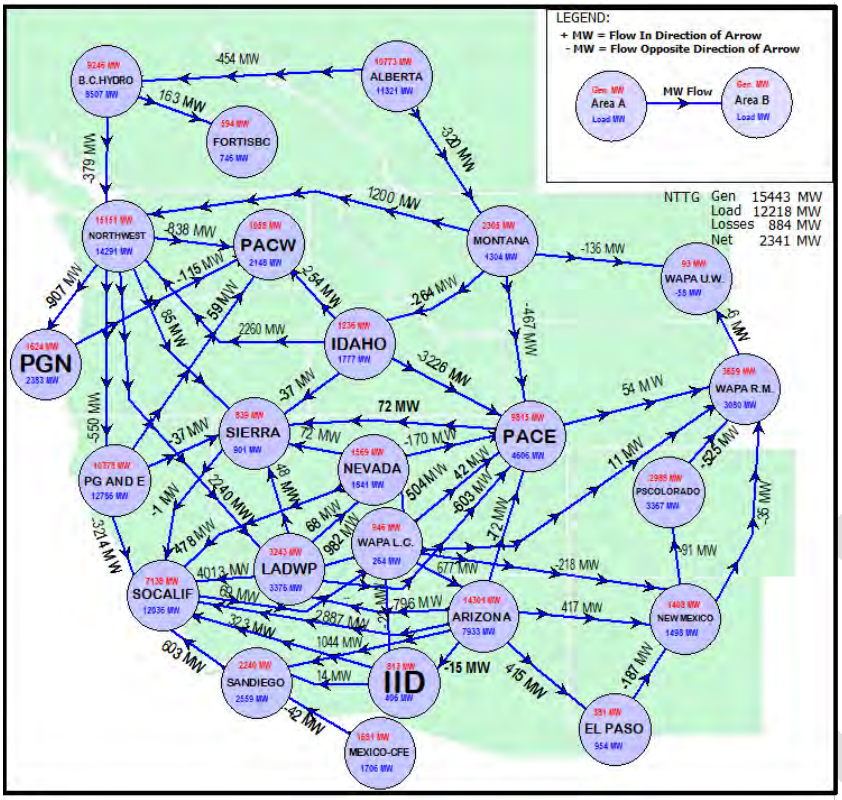


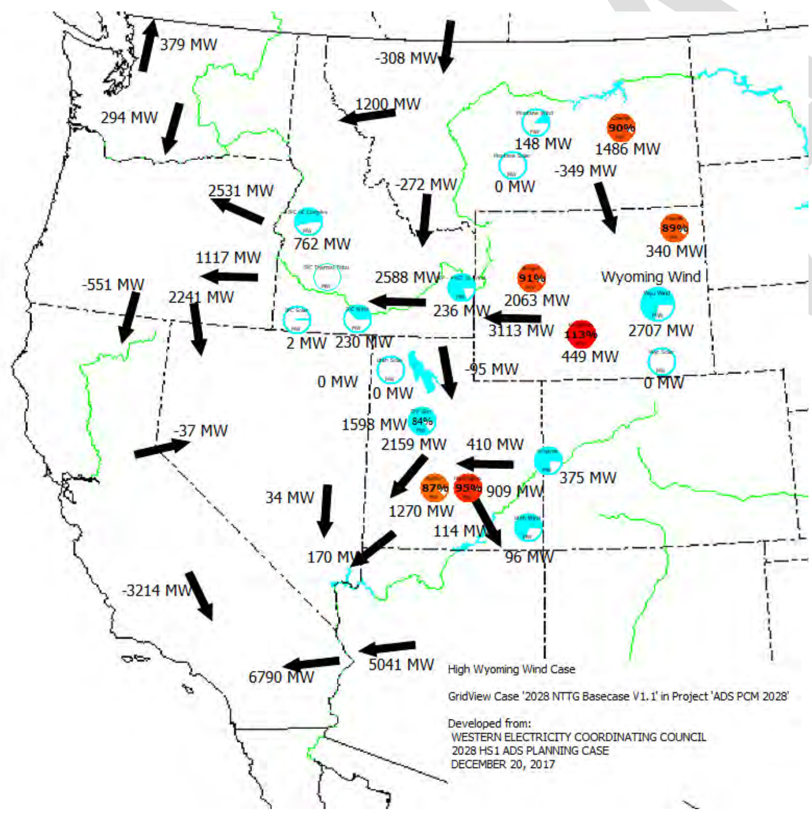
Case E – High Tot2/COI



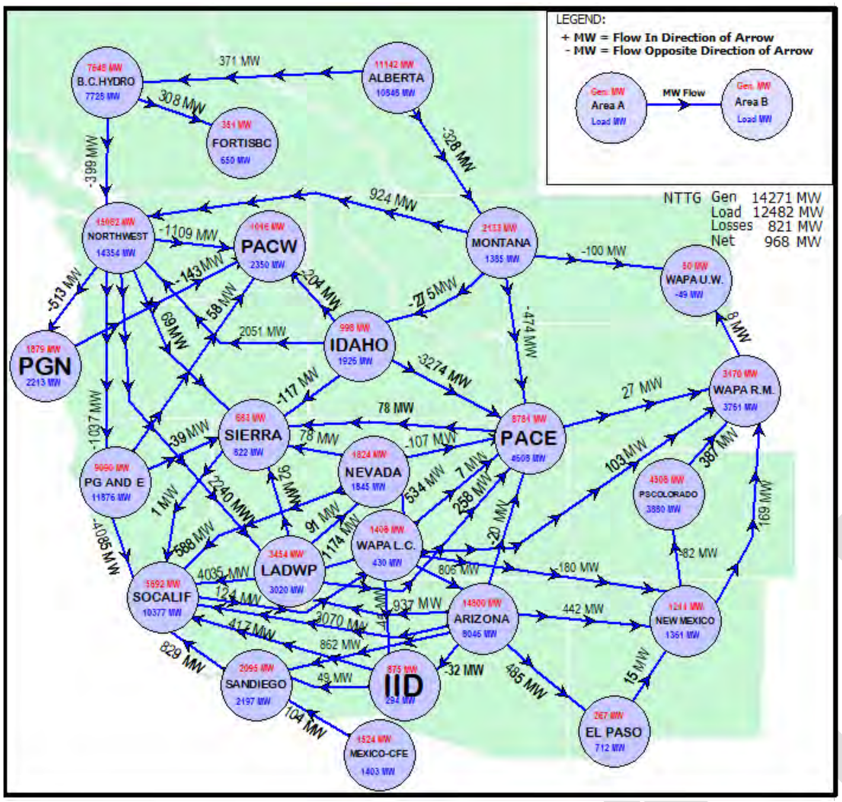


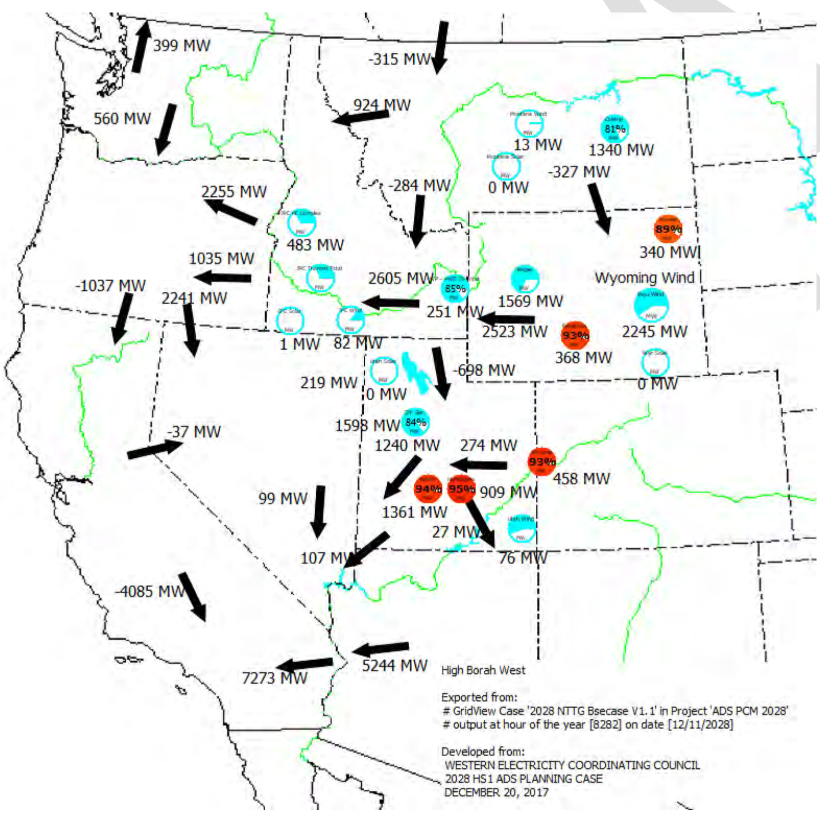
Case F – High Wyoming Wind



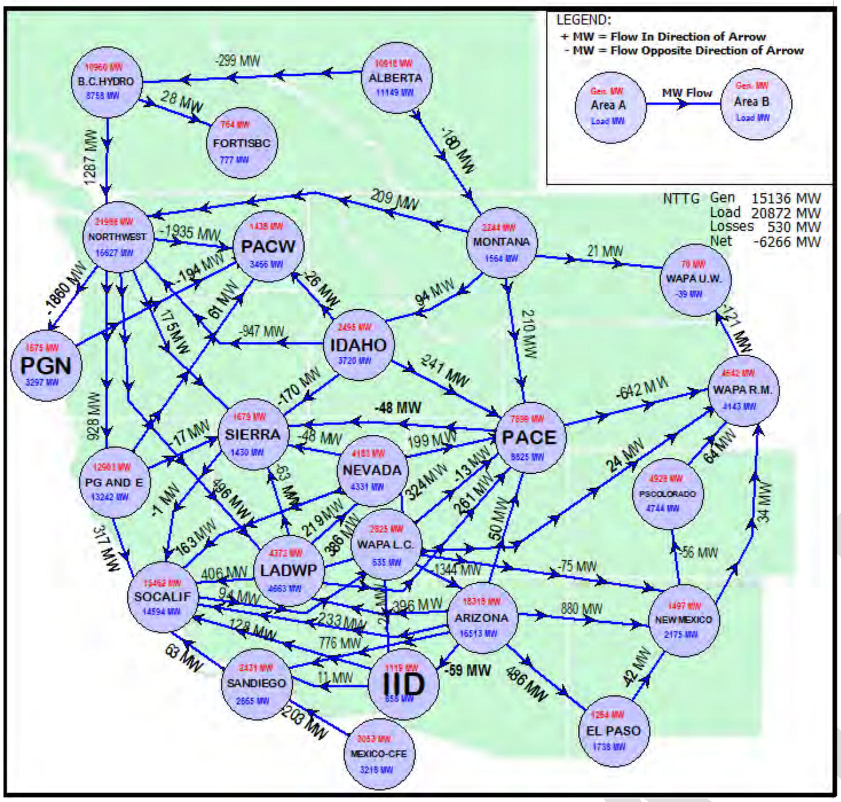


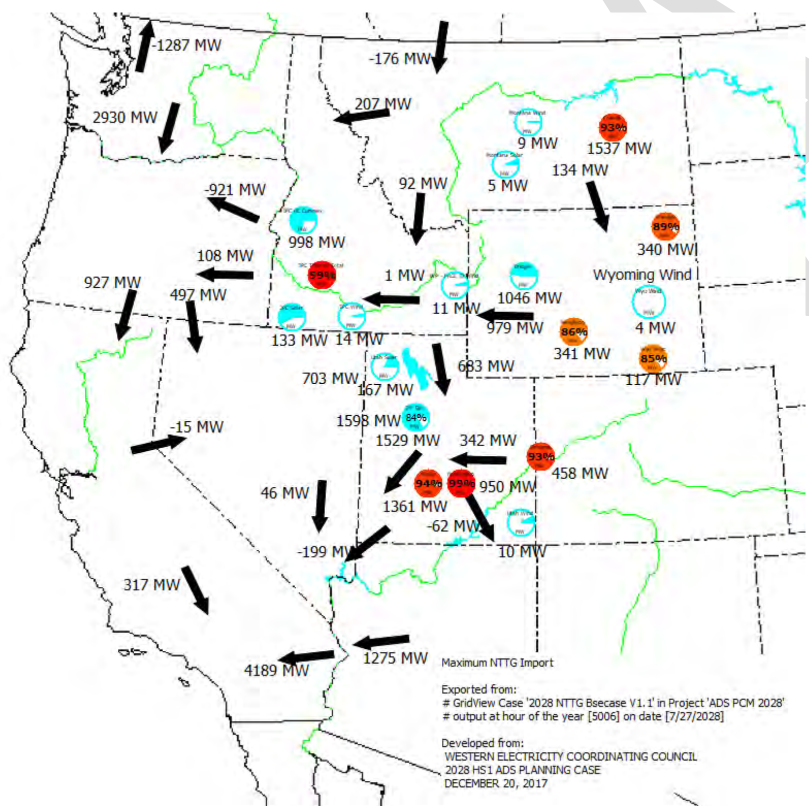
Case G – High Borah West



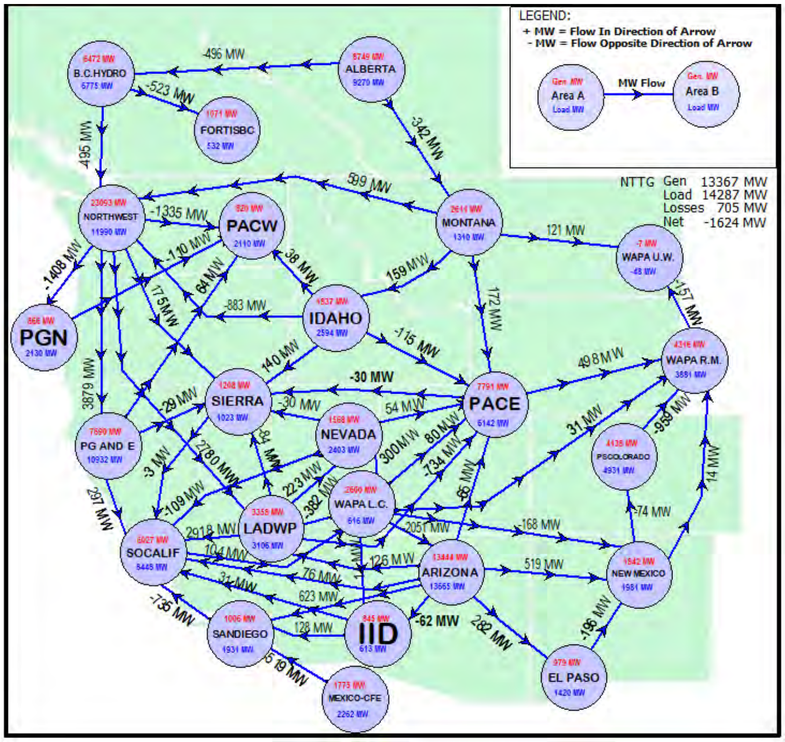


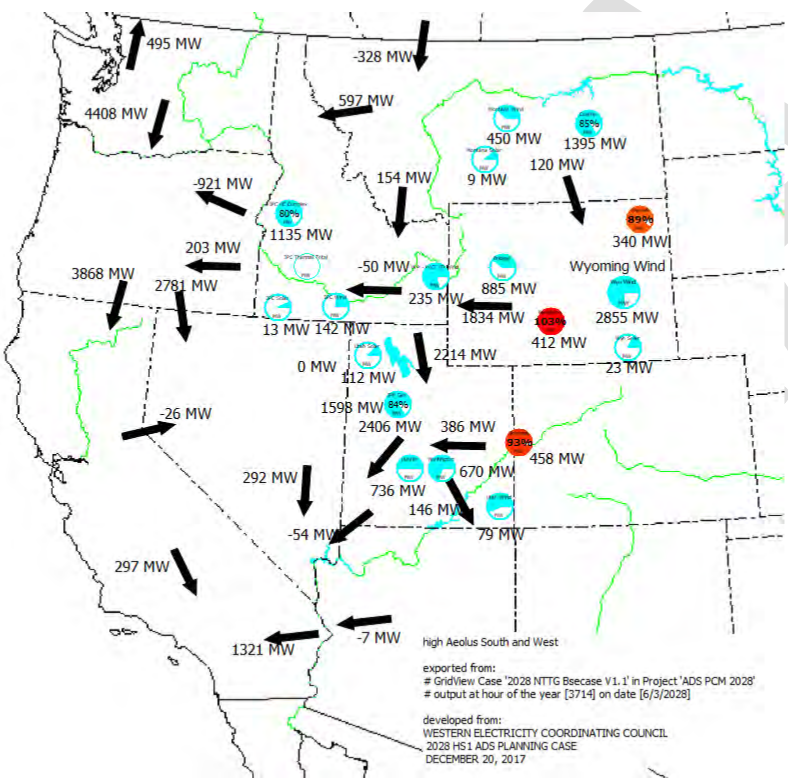
Case H – Low Wyoming Wind



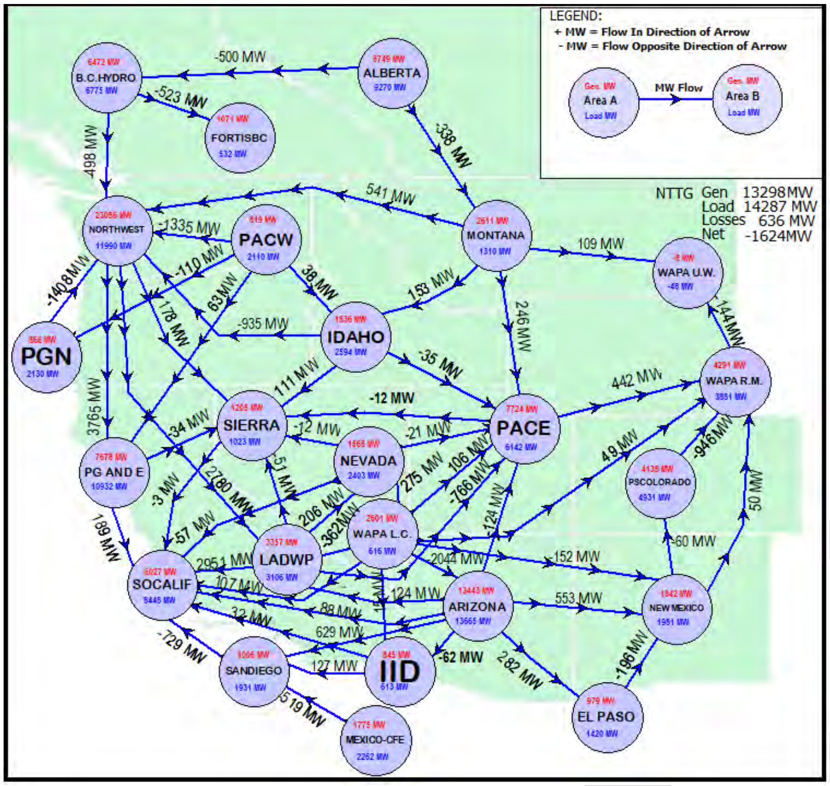


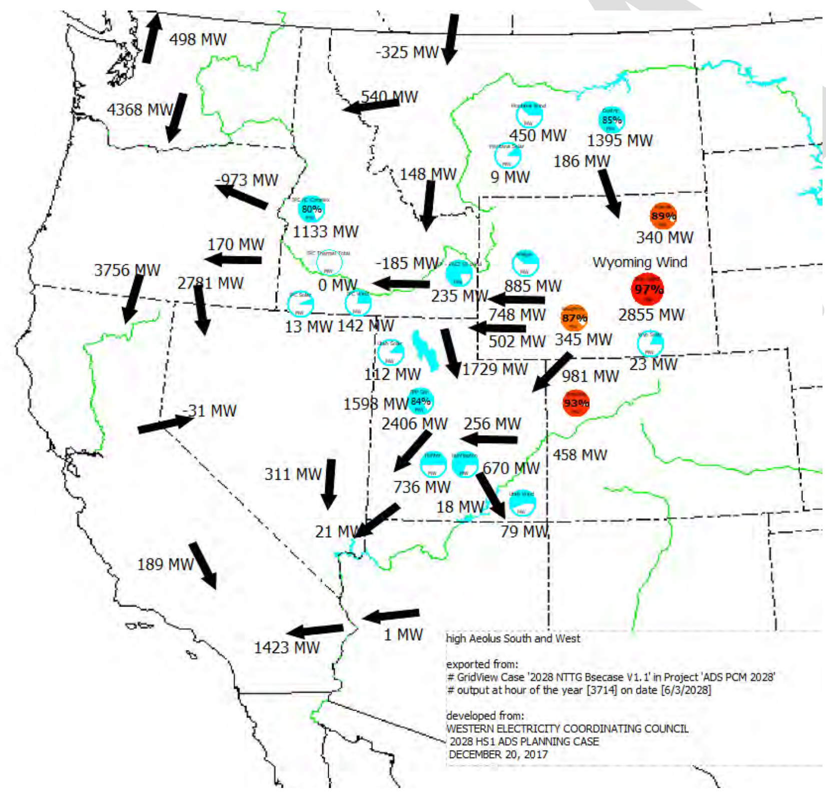
Case I – High Aeolus West and South – ESR Configuration





Case I – dRTP Configuration



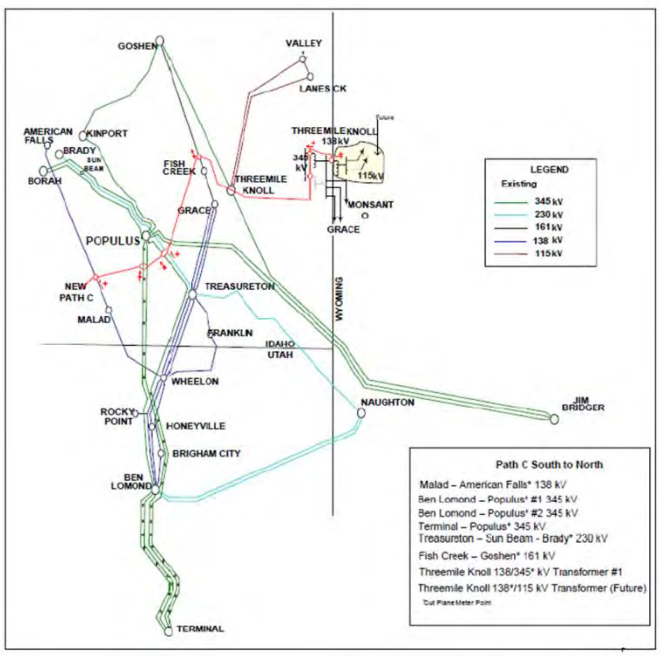


Attachment – B

Path C Corridor Constraints

PacifiCorp has previously indicated that an additional transmission corridor south of Populus is not a viable transmission solution. During efforts to complete the Populus – Terminal 345 kV Project in 2010, PacifiCorp utilized all available EHV transmission corridors between southeast Idaho and northern Utah. To aid in the discussion, we have included a single-line of the southeast Idaho to northern Utah transmission system, below.

The most significant "pinch-point" in Path C is just north of Ben Lomond near Willard Bay. In this section there is a four mile-line section of line, which is constructed on top of the Willard Bay dyke. At one point in the corridor the width between the Willard Bay dyke and Mount Ben Lomond is less than one mile. In this narrow area, is a single-circuit 345 kV, double-circuit 345 kV, three 138 kV lines, Interstate 15, double-track Union Pacific Railroad, homes and businesses.



While the current single-circuit 345 kV transmission structures have been constructed on the dyke, the structures are not designed for double-circuit and would need to be replaced. It is anticipated that Weber Basin Water Conservancy District, who operated Willard Bay for irrigation will not allow new structures to be constructed on top of the Willard Bay dyke – due to risk to an aging dyke, and risk of triggering federal government oversite to the worthiness of the entire dyke to meet current national standards.

Additionally, constructing a new line south of Ben Lomond to Terminal would require the condemnation of 60 to possibly over 100 homes and businesses.

Revision History

Version	Date	Comment	Author
Version 0.5	10-31-2018	Version for internal review prior to public review and comment	R Schellberg
Version 1.0	12-28-2018	Version for Stakeholder Review	R Schellberg
Version 1.2.1	2-13-19	Revisions incorporating Stakeholder Comments approved by Planning Committee	R Schellberg
Version 2.0	5-17-19	Initial version of draft final RTP for internal review	R Schellberg
Version 2.1	6-2-19	Revisions to incorporate more Q5 discussion and added Robustness section detail	R Schellberg
Version 2.2	6-4-19	Incorporate TWG Comments	R Schellberg
Version 2.3	6-28-19	Posted for Stakeholder Comments	R Schellberg
Version 3.0	7-21-19	Incorporated Stakeholder Comments	R Schellberg
Version 4.0	9-18-19	Incorporated 2019 ESR Report Following NTTG Planning Committee Approval	A Wachsnicht