Amended
NTTG Biennial Study Plan
for the
2018-19 Regional Planning Cycle

Idaho Power
230-kV double-circuit transmission line between Idaho Power's Oxbow and Hells Canyon hydroelectric projects

This biennial Study Plan outlines the process to be followed by the NTTG Planning Committee in performing the 2018-19 biennial regional transmission planning process, as required under FERC Orders No. 890 and 1000, Attachment K – Regional Planning Process.

Approved by NTTG Steering Committee: 7/10/18
Amended Study Plan Approved by NTTG Steering Committee: 12/18/18

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I. Introduction

This Biennial Study Plan[1] (study plan) outlines the study process that the Northern Tier Transmission Group (NTTG) will follow to develop the ten-year Regional Transmission Plan[2] for the planning cycle covering years 2018-2019. In addition to the information pertaining to the development of NTTG's 2018-19 Regional Transmission plan, this study plan also describes NTTG's process to determine if a properly submitted Interregional Transmission Project ("ITP") is a more cost effective or efficient solution to one or more of NTTG's regional transmission needs. This study plan will rely on the loads, resources, point-to-point transmission requests, desired flows, constraints and other technical data that were submitted in Quarter 1 and will be subsequently updated in Quarter 5 of the Regional Planning Cycle, and will be considered in the development of NTTG's 2018-19 Regional Transmission Plan. Additionally, the methodology, criteria, public policy requirements and considerations, assumptions, databases, identification of the analysis tools and project identification (including Initial Regional Plan and Alternative Projects[3]) will be established within the study plan and posted for comment by stakeholders and Planning Committee members. If there are any differences between what is stated in this study plan and the process stated in Attachment K of the NTTG FERC Order 1000, Attachment K will take precedent.

The NTTG Planning Committee chair has established the Technical Work Group (TWG) subcommittee to undertake the development of this study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan and assess any ITPs submitted to NTTG. The TWG is established at the beginning of each biennial planning cycle and is comprised of individuals who are NTTG Planning Committee members or their designated technical representative, have signed NTTG's Confidentiality Agreement and have been authorized to have access to confidential data by any entity who may have submitted confidential data to NTTG. Members of the TWG work at the direction of the NTTG Planning Committee Vice-Chair, must have access to and expertise in power system power flow analysis

[1] Capitalized terms in this document are from Attachment K definitions
[2] Throughout the planning cycle the Regional Transmission Plan will be represented by the Draft Regional Transmission Plan or the Draft Final Regional Transmission Plan.
[3] An Alternative Project refers to Sponsored Projects, projects submitted by stakeholders, projects submitted by Merchant Transmission Developers, and unsponsored projects identified by the Planning Committee (if any).

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or production cost modeling and are committed to accepting and completing technical planning assignments in a cooperative and timely manner.

II. Study Objective

The objective of the transmission planning study is to produce the NTTG Regional Transmission Plan, through the evaluation and selection of projects that meets the transmission needs within the NTTG footprint on a regional and interregional basis that are more efficient or cost effective than the Initial Regional Plan ("iRTP").

III. General Schedule and Deliverables

The broad timing of the Regional Transmission Plan Development process and the work products to be delivered are presented in each of the NTTG Transmission Providers' Attachment K:

- **Quarter 1:** Collect load and resource forecasts, new regional and interregional transmission projects (sponsored, unsponsored and merchant), point-to-point transmission requests, and transmission needs driven by public policy requirements and considerations from stakeholders.
- **Quarter 2: By April 15th,** evaluate the completeness of data received from stakeholders and resolve any deficiencies. Develop the Biennial Study Plan for approval by the Steering Committee.
- **Quarters 3 and 4**: Analysis and Development of the Draft Regional Transmission Plan. The submitted system loads, resources, regional and interregional transmission project solutions will be modeled, and technical screening studies will be performed to evaluate the Initial Regional Plan and a Change Case with Alternative Projects. By the end of Quarter 4 NTTG will post a Draft Regional Transmission Plan.
- **Quarter 5:** Stakeholders may review and comment on the Draft Regional Transmission Plan. Stakeholders may also submit new unsponsored projects during Quarter 5. New unsponsored projects will be considered, to the extent feasible, as determined by the Planning Committee without delaying the development of the Regional Transmission Plan. Stakeholders may also provide updates that may lead to a material change from data submitted in Quarter 1. The updated data will be evaluated by the TWG as part of the preparation of the Draft Final Regional Transmission Plan (DFRTP).
- **Quarter 6**: Cost allocations studies and analysis. The TWG will then prepare the DFRTP.
- **Quarter 7**: Stakeholders' are to review and comment on the DFRTP and the TWG will consider the Quarter 5 updates and unsponsored projects and stakeholder comments to produce a Revised Draft Final Regional Transmission Plan.

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- **Quarter 8**: The Planning Committee will submit the Regional Transmission Plan for NTTG Steering Committee approval and the Regional Transmission Plan will be posted.

IV. Study Assumptions and Representation

A. Major Study Assumptions and System Representation

1. Data Assumptions

The following loads, resources, transmission service obligations, transmission project and alternative project assumptions will be applicable for all NTTG transmission planning studies performed as part of this study plan:

a. Loads: The forecasted loads for Balancing Authority Areas internal to the NTTG footprint were provided in response to the Quarter 1 data request. These loads are generally those in the participating load serving entities' official load forecasts (such as those in integrated resource plans) and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. Table 1 below shows a load comparison from data submitted during Quarter 1 of 2018 compared with loads that were forecasted in 2016-2017 study 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)	Difference (MW) 2026-2028
Idaho Power	3,806	4,346	4,412	66
NorthWestern	1,803	1,992	2,027	35
PacifiCorp	12,634**	13,044	13,386	342
Portland General	4023	3,885	3,928	43
TOTAL*	22,266	23,267	23,753	486

* Loads for Deseret G&T and UAMPS are included in PacifiCorp East
** 2016 July Peak Demand

Table 1: January 2018 Data Submittal – Load Comparison

b. Resources: Resources provided in response to the Quarter 1 data requests are incremental to existing resources within the NTTG footprint and are summarized in Figure 1 and Table 2 below.

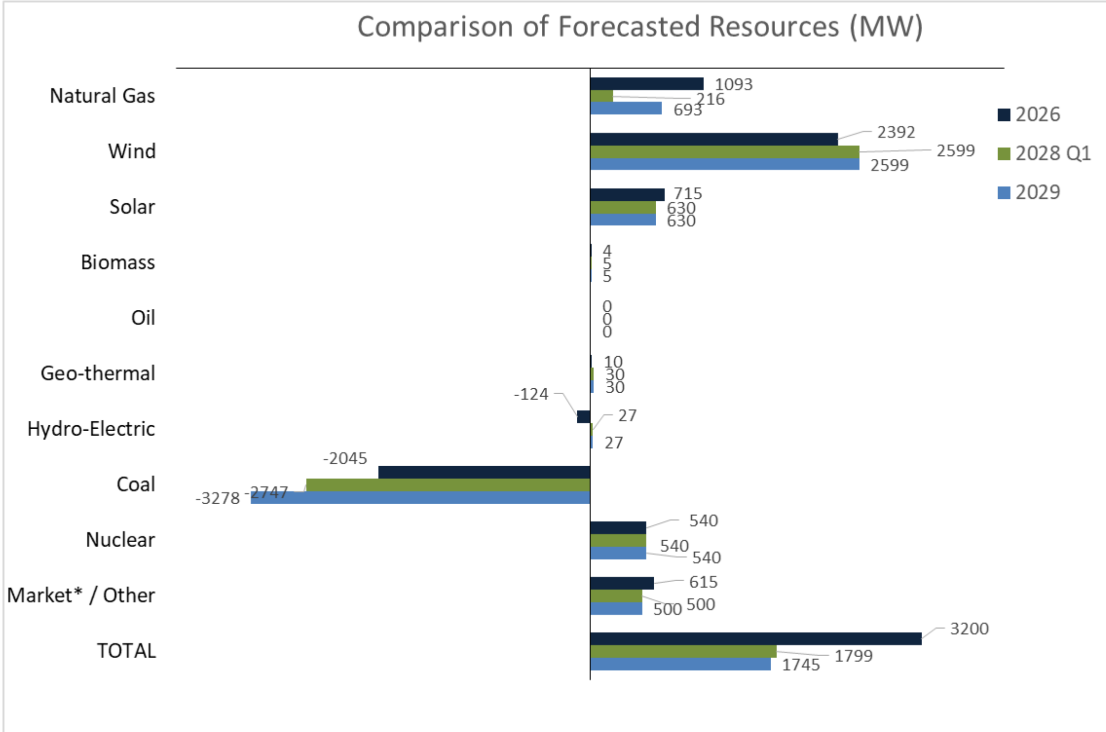

Figure 1: Comparison of Forecasted Resources

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

State	Resource Additions (MW)
Arizona[4]	-414
California	0
Colorado	-82
Idaho	588
Montana	573
Oregon	-391
Utah	452
Washington	108
Wyoming	727[5]

[4] Reflects PacifiCorp's retirement of Cholla 4 and Craig 1, which are coal resources outside the NTTG footprint.
[5] 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.

Table 2: Location of 2028 Forecasted Resources

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

Attachment K states that retirements before "… the tenth year of a ten-year planning horizon counted from the first year of the Regional Planning Cycle[6]" should be modeled. That would include retirements up to and including the Dave Johnson Units. The Planning Committee recommends that a sensitivity case be considered to reflect the planned retirements and replacement energy resources that would occur immediately following the ten-year next planning horizon (detailed in Table 3) to ensure that unnecessary transmission would not be recommended in the RTP for a short term change in resources levels. This Study Plan will assess those sensitivities either by modifying select powerflow cases or by extracting dispatch hours from a modified Production Cost Model run.

Coal Unit	Retirement Date[7]	Study Treatment
Naughton 3	12/2018	Retired
Valmy 1	12/2019	Retired
Boardman	12/2020	Retired
Cholla 4[4]	12/2020	Retired
Colstrip 1 & 2	7/2022	Retired
Valmy 2	12/2025	Retired
Craig 1[4]	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[8]

Regional Transmission Projects: Listed below in Table 4 are the regional transmission projects that were submitted in Quarter 1. The project types may be either prior Regional Transmission Plan (pRTP), Full Funder Local Transmission Plan (LTP), Sponsored Project, unsponsored Project, or Merchant Transmission Developer. The Initial Regional Transmission Plan will be derived from projects included in the prior Regional Transmission Plan and projects included in the Full Funders local transmission plans. The TWG after consultation with the project submitters, identified the regional transmission projects shown in the table below as the list of regional

[6] Idaho Power OATT, section 18.4.1

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

[8] 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.

projects submitted in Quarter 1 data submittal that will be analyzed during this biennial Regional Planning Cycle.

MARCH 2018 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2028

Submitter	From	To	Voltage	Circuit	Type	Regionally Significant[9]	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)
	Cedar Hill	Hemingway	500 kV	1	LTP	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	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	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)

[9] 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

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			115 kV	1	LTP	No	Yes	Various Load Service Additions (2019-2024)

Table 4 – New Transmission Projects

The Sponsored Projects will be evaluated through the use of Change Cases as described below. Additionally, Merchant Transmission Developer and unsponsored projects will be evaluated in Change Cases to produce, if possible, a more efficient or cost effective Regional Transmission Plan.

c. Transmission Service Obligations: Listed below in Table 5 are the transmission obligations that were submitted in Quarter 1.

Submitted by	MW[10]	Start Date	POR	POD
Idaho Power	500/200	2021	Northwest	IPCo
	250/550	2022	LGBP	BPASEID

Table 5 – Transmission Service Obligations

d. 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.

[10] Summer/Winter service requirements

** 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

e. Interregional Transmission Projects: The following table provides a list of ITPs received in Q1.

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[11]	Great Basin Transmission LLC	CAISO[12], NTTG, WestConnect	Midpoint, ID	Robinson Summit, NV	Permitted	2021
TransWest Express Transmission DC/AC Project[12]	TransWest Express, LLC	CAISO, NTTG, WestConnect	Rawlins, WY	Boulder City, NV	Conceptual	2020
TransWest Express Transmission DC Project[13]	TransWest Express, LLC	CAISO, NTTG, WestConnect	Rawlins, WY	Boulder City, NV	Conceptual	2020

Table 7 – Interregional Transmission Projects

2. Analysis Tools

Three types of analysis tools will be utilized in the development of the power flow base cases. These are:

Power flow – The PowerWorld[14] power flow software will be used to evaluate transmission reliability under N-0 and N-1 conditions as well as certain credible N-2 contingencies. System performance analyses are conducted using power flow programs, given a snapshot of loads, resources and network topology provided by production cost studies, to determine whether the transmission grid can be operated to allow the electricity to flow reliably.

[11] 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.

[12] CAISO has volunteered to participate in the studies and accept cost allocation.

[13] 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.

[14] PowerWorld is an interactive power systems simulation package for the analysis of high voltage power systems operation and is a product of PowerWorld Corporation

Dynamic Analysis – The dynamic analysis will be based on selected Power flow cases and the availability of the dynamic models for the newly submitted projects.

Production Cost –The GridView[15]production costing software will be used to evaluate the range of production scenarios that may occur in the Western Interconnection. Production cost study(s) results will be used to create power flow seed case assumptions for several stressed hours during the year.

Study cases will be maintained in the PowerWorld power flow and GridView production costing database formats and made available to stakeholders interested in verifying, further analyzing, or extending the work done in this planning process, provided that appropriate steps are taken to maintain confidentiality.

3. Regional Plan Evaluation

This study process will evaluate the Initial Regional Plan, Regional and Interregional Transmission Project submittals and Alternative Projects through the creation of Change Cases.

The steps of the study process include the following:

- The cost and other physical information with respect to transmission projects forming the Initial Regional Plan and Alternative Projects (Sponsored, unsponsored submissions by stakeholders, or unsponsored identified in the prior Biennial Cycle) will be compiled for the tenth-year of the study period (study year) from data submissions, along with all other data to be used in the Interconnection-wide power flow and production cost modeling.
- A production cost model base case of the Initial Regional Plan, comprised of multiple hours within the study year, will be developed using the production cost program, GridView, to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint.
- The production cost model base case consisting of those load, resource and interchange data (the combination of input and output data) for these selected hours will be transferred from GridView to a power flow model, PowerWorld, using the round-trip process pioneered by NTTG. These power flow seed cases will be adjusted to meet the desired case objectives to form the base cases for further technical analysis.
- Using the power flow base cases, the Initial Regional Plan will be evaluated using power flow analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs including needs associated with Public Policy Requirements. If the power flow base case fails to meet these minimum performance or transmission need requirements, then one or more sponsored or unsponsored Alternative Project(s) that correct the deficiency(ies) or an unsponsored

[15] GridView is a production costing tool and product of ABB

Alternative identified by the TWG will be included in the Initial Regional Plan base case. The study process as outlined below will be used to develop an Initial Regional Plan that meets the system performance requirements and transmission needs associated with Public Policy Requirements.

- Change Cases will be developed by the addition of an Alternative Project and/or ITPs to the Initial Regional Plan. Each Change Case may also exclude one or more Non-Committed Projects in the Initial Regional Plan provided the substitution of the Non-Committed Project(s) with Alternative Project(s) in the change case have similar or better reliability impacts and is more efficient or cost effective.
    - Analysis will be performed as needed to determine whether or not NTTG's transmission providers' future transmission system accommodates potential future transmission obligations as provided in the Q1 and/or Q5 data submittals. This analysis may encompass a power flow reliability analysis and/or a comparison between submitted transmission service obligations versus available transfer capability.
    - The ATC values listed in Table 6, plus any transmission capacity increase estimated from power flow analysis with and without the non-Committed transmission projects, will be compared to existing plus future transmission service obligations received during the Quarter 1 and/or Quarter 5 data submittal periods.
    - As part of the development of Change Cases, the TWG will also determine if there are additional Alternative Projects (which could include variations/modifications of projects submitted by a Sponsor or stakeholder) that should be evaluated through inclusion in a Change Case.
- Each Change Case will be evaluated to determine whether or not it meets the System Performance requirements and the transmission needs associated with Public Policy Requirements and other transmission obligations. If it fails to meet these minimum requirements, it will either be (i) set aside as unacceptable or (ii) modified by the TWG by the addition of another Alternative Project (which may include an unsponsored project identified by the TWG to form a new Change Case that will be subject to evaluation).
- The Initial Regional Plan and Change Cases power flow analysis will monitor the impacts of projects under consideration in the Initial Regional Transmission Plan on neighboring Planning Regions as well. If the Change Case or Initial Regional Plan may cause reliability standard violations on neighboring Planning Regions, the Planning Committee shall coordinate with the neighboring Planning Regions to reassess and redesign the facilities. If the violation of reliability standards can be mitigated through new or redesigned facilities or facility upgrades within the NTTG Footprint or through operational adjustments within the NTTG Footprint, the costs of such mitigation solutions shall be considered in addition to the cost of the project(s) under consideration when selecting a project for the Draft Regional Transmission Plan.

- The TWG will then review each Change Case to determine if a modification of any Change Case should be developed and evaluated that would be more efficient or cost effective in meeting regional transmission needs.
- A limited number of dynamic analysis studies will be performed on the Change Cases. If a Change Case fails to meet dynamic stability requirements, it will either be (i) set aside as unacceptable or (ii) modified by the TWG by the addition of another Alternative Project (which may include an unsponsored project identified by the TWG to form a new Change Case that will be subject to evaluation) or other mitigation measure.
- Those Change Cases that are acceptable will be evaluated using three economic metrics for the study year: capital-related costs, energy losses, and reserves. The monetized incremental cost of each metric will be summed for each Change Case as compared with the Initial Regional Plan.
- If an examination of the incremental costs suggest that a different combination of Alternative Projects may result in Change Cases which are more efficient or cost effective than the Initial Regional Plan, then a new Change Case will be developed as a combined Alternative Project into one or more additional Change Cases.
    - When necessary, these new Change Cases will be re-evaluated to ensure each continues to meet the system performance requirements and transmission needs associated with Public Policy Requirements and other transmission obligations. For each new Change Case meeting these minimum requirements, the monetized incremental cost will be determined using the three metrics described above. Based on review by the TWG of the results for the new Change Cases, the process of developing and evaluating additional Change Cases from the Alternative Project initially selected may be repeated.
- The set of projects (either the Initial Regional Plan or a Change Case) with the lowest incremental cost, as adjusted by its effects on neighboring regions will then be incorporated into the Draft Regional Transmission Plan.
- The allocation scenarios developed by the Cost Allocation Committee (in consultation with the Planning Committee) for those parameters that will likely affect the amount of total benefits and their distribution among Beneficiaries will be evaluated using the Draft Regional Transmission Plan.
- All or portions of the above planning process may be used by the TWG to complete additional analysis to develop the Draft Final Transmission Plan.

4. 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[16] through the Local Transmission Plans of the NTTG Transmission Providers. Additionally, during Quarter 1, 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. During the Regional Planning Cycle, the Planning Committee will determine if there is a more efficient or cost-effective regional solution to meet these transmission needs.

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. All transmission needs identified as driven by Public Policy Requirements, and available at the time this revised NTTG Biennial Study Plan was developed, will be included in the study plan.

During this 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 Attachment 1. The following RPS values will be used in its modeling:

	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

B. Transmission Planning Study Methodology

1. Request and Evaluate Data

Proper analysis of the NTTG transmission system requires data and models that describe the entirety of the Western Interconnection due to the significant transmission ties between regions and the substantial energy trading markets that span the interconnection. Consequently, NTTG

[16] See Attachment K, Local Planning process

bases its study efforts on the data collection and validation work of the Western Electricity Coordinating Council (WECC) and its committees.

The WECC Anchor Data Set[17] (ADS) database will be reviewed and modified as needed to assure conformance with the Initial Regional Plan. NTTG intends to use the ADS 2028 production cost base case with round trip capability as the foundation of its work. It is expected to be available by the end of Q2, should its availability be delayed, the TWG may have to develop an alternate base case for the foundation of its studies.

Reevaluation of selected projects in prior Regional Transmission Plan

NTTG expects the sponsor of a project selected in the prior Regional Transmission Plan (the "Original Project") to inform the Planning Committee of any project delay that would potentially affect the in service date as soon as the delay is known and, at a minimum, when the sponsor re-submits its project development schedule during quarter 1. If the Planning Committee determines that the Original Project cannot be constructed by its original in-service date, the Planning Committee will reevaluate the Original Project in the context of the current Regional Planning Cycle using an updated in-service date.

"Committed" projects, in the context of re-evaluation, are Original Projects that have all permits and rights of way required for construction, as identified in the submitted development schedule, by the end of quarter 1 of the current Regional Planning Cycle. Committed projects are not subject to reevaluation, unless the Original Project fails to meet its development schedule milestones such that the needs of the region will not be met, in which case, the Original Project loses its designation as a Committed project.

If "not Committed," the Original Project —whether selected for cost allocation or not — shall be reevaluated, and potentially replaced or deferred, in the current Regional Planning Cycle only in the event that:

a. The Project Sponsor fails to meet its project development schedule such that the needs of the region will not be met,
b. The Project Sponsor fails to meet its project development schedule due to delays of governmental permitting agencies such that the needs of the region will not be met, or
c. The needs of the region change such that a project with an alternative location and/or configuration meets the needs of the region more efficiently or cost effectively.

If condition (a), (b), or (c) is true, then the incumbent transmission provider may propose solutions that it would implement within its retail distribution service territory footprint (the "New Project"). Both the Original Project and the New Project will be reevaluated or evaluated,

[17] WECC ADS process has four main functions: 1) oversee and maintain public databases for transmission planning; 2) develop, implement, and coordinate planning processes and policy; 3) conduct transmission planning studies; and 4) prepare Interconnection-wide transmission plans.

respectively, in Quarter 2 as any other project for consideration in the Regional Transmission Plan.

During such reevaluation the Planning Committee shall only consider remaining costs to complete the Original Project against the costs to complete the other projects being evaluated.

2. Production Cost Model Analysis Define System Conditions to Study

The TWG studies will use production cost model analysis to examine all hours of the year for situations where available resources and forecasted loads across the Western Interconnection cause highest stress such as peak load, high transfers with other regions, etc. on the transmission system in the NTTG footprint. Figure 2 below illustrates the future transmission projects modeled in the WECC ADS 2028 base case.

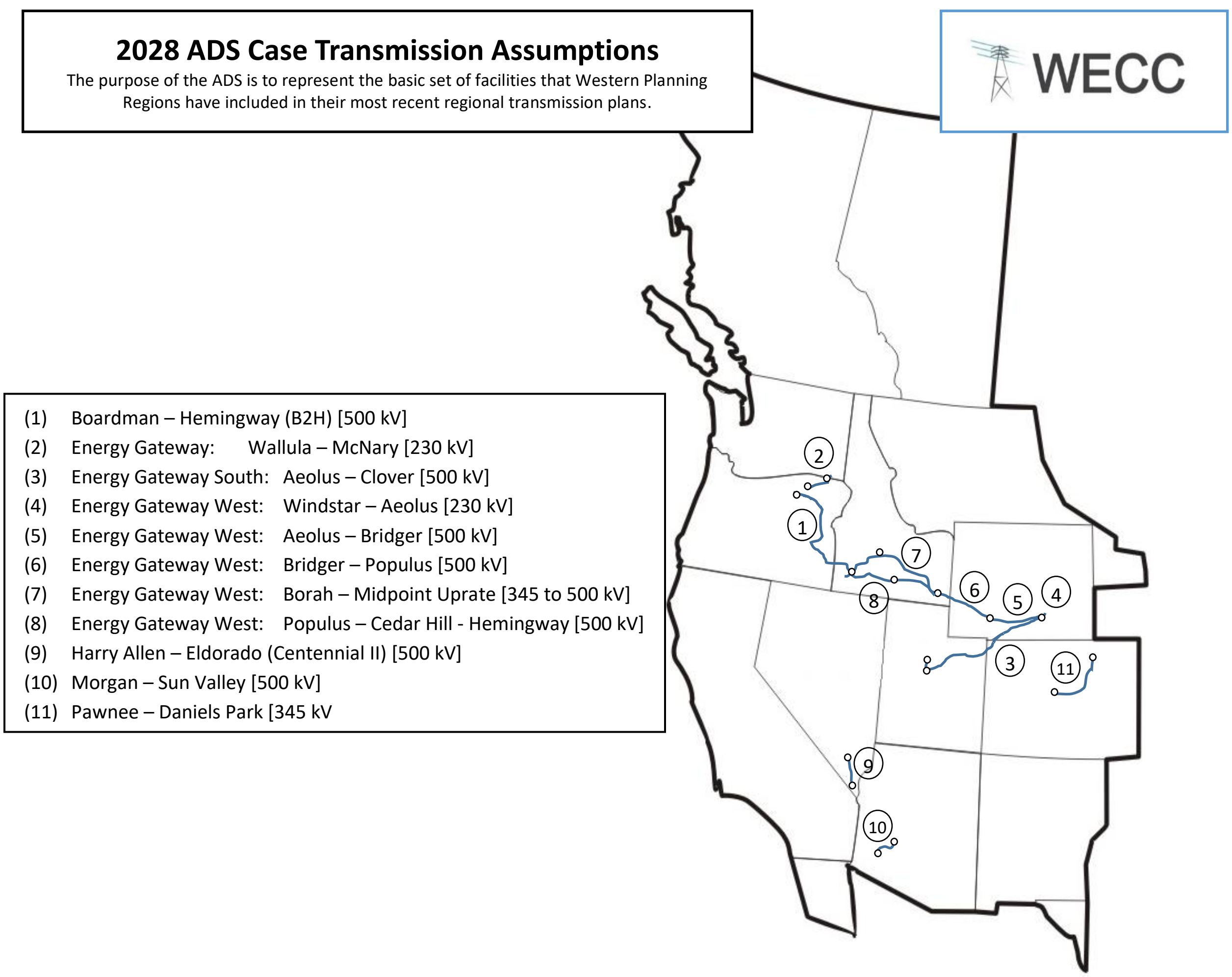


Figure 2 – ADS Significant Regional Transmission used in NTTG Studies

The WECC 2028 ADS production cost model will be analyzed for selecting hours for power flow analysis.

Using the ADS 2028 production cost model and the GridView production cost software, the TWG will identify the hourly data for several system conditions, such as:

a) peak coincident NTTG summer load condition;

b) peak coincident NTTG winter load condition;

c) conditions with high import (above 2000 MW) from the Northwest to Idaho;

d) conditions with high flows (above 3000 MW) from Idaho to the Northwest;

e) conditions with high flows (above 1300 MW) across the Utah/Nevada to Southeast interfaces (Tot2B & Tot2C) in combination with high COI North to South flows (above 4000 MW), which may be useful in studying ITPs focused on fulfilling future RPS requirements;

f) High Simultaneous Wind production[18]; and/or

g) conditions where persistent congestion observed in the NTTG PCM case that might warrant transmission system reinforcement.

The hours that approximate the above system conditions will be identified, if possible, from the Production Cost Model results for power flow evaluation. Additional hour(s) representing a system condition(s) of interest to study may be identified through the production cost model results review and added to or replace one of the conditions identified above.

3. Power Flow Databases

a) Base Cases

The base cases for the various desired system conditions to be simulated are described in Section IV.B.2 above. These power flow cases will be derived from the ADS 2028 production cost model. The TWG will import the seed case data for each system condition (i.e., an exported hour) into the PowerWorld power flow program and create base cases for each of the study conditions. The powerflow seed case data will be adjusted to meet the desired system condition, significant changes to the exported seed case will be tracked and documented. For example, for coincident load conditions, the loads will be adjusted from 1 in 2 conditions in the ADS 2028 to an approximate 1 in 5 condition, since each TP contributes differing amounts to the coincident peak condition, the scaling factors will be different for each TP. For flow-based conditions, the Load and Resource balance will be adjusted to meet the objectives of the study condition.

As mentioned in the resource section above, sensitivity cases from the base cases will be developed to address resource changes that may occur and not modeled in the ADS 2028 production cost model.

[18] Using a simultaneous analysis described in Attachment 2.

For any updated L&R data (or other data) received in Quarter 5, the Technical Work Group will make a determination if it is appropriate to update the power flow data with the updated loads, resources and transmission information when conducting the additional reliability studies.

b) Change Cases

The TWG may add any number or combination of Alternative Projects or ITPs and may remove any non-committed transmission facilities from the base cases, as appropriate, in order to create Change Cases for the respective base cases. These Change Cases will be used for comparison purposes in evaluating the more efficient or cost-effective Regional Transmission Plan.

4. Steady-State (N-0), and Contingency (N-1, N-2) Analysis

Power flow steady-state (N-0) and contingency (N-1, credible N-2) analysis will be performed using the procedures outlined in the WECC Data Preparation Manual, including utilizing governor power flow techniques for contingencies resulting in the loss of generation. Selection of specific contingencies shall be provided by NTTG members. The Peak RC standard contingency lists will be used for multiple contingency scenarios. All Special Protection Schemes related to the N-1 and N-2 contingencies, if any, will be included in the analysis.

A limited number of dynamic analysis studies will be performed. The TWG will use professional judgement to define the set of outage conditions that may result in instability or reliability performance issues.

5. System Performance (Reliability) Criteria[19]

The power-flow simulation performance results will be measured against the North American Electric Reliability Corporation (NERC) and WECC system performance criteria. Specifically, the NERC Reliability Standards TPL-001-4 requires transmission facilities to operate within normal and emergency limits.

The WECC System Performance Regional Business Practice TPL-001-WECC-CRT-3 establishes the basis for voltage performance criteria. The TWG will monitor and report post contingency and steady state voltages outside the following boundary conditions:

Nominal Voltage/Equipment	Less than or equal (pu)	Greater than or equal (pu)
500 kV	1.1	0.95
345 kV	1.05	0.95
Series capacitor and series reactor line	1.15	0.9

Table 9 – System Performance Table

[19]WECC has changed the terminology from Reliability Criteria to System Performance Criteria

The TWG will include in the Draft Regional Transmission Plan violations and mitigation measures on Bulk Electric System (BES) transmission elements based on local system performance criteria and exceptions as documented in the WECC Guideline, "Disturbance-Performance Exceptions". However, local transmission provider (within the same transmission system where contingency applied), series-capacitor and non-bulk-electric-system bus violations will not be reported.

- ***Pre-contingency State*** – Power-flow simulation performance requires all transmission facilities to operate within their continuous ratings under steady state conditions. The requirements for the pre-contingency performance criteria are summarized in the NERC's Transmission Planning standard TPL-001-4.
- ***Single Contingencies*** – Power-flow simulation performance results require all transmission facilities to operate within emergency limits following single contingences. The requirements for the post-contingency performance criteria are summarized in the NERC's Transmission Planning standard TPL-001-4.
- ***Credible Multiple Contingencies*** – Power-flow simulation performance results require all transmission facilities to operate within emergency limits following credible multiple contingences. The requirements for the (credible multiple contingency) post-contingency system performance criteria are summarized in the NERC's Transmission Planning Standard TPL-001-4.
- ***Dynamic Contingencies*** – The TWG will utilize engineering judgement to study a subset of the single contingencies, and credible multiple contingencies, as dynamic contingencies to evaluate the transient stability of the transmission system.

The viability of specific transmission projects will be evaluated using power flow software to demonstrate compliance with NERC and WECC system performance criteria as noted above, and other system specific system performance criteria noted below shall also apply:

1) NorthWestern Energy, Criteria - https://www.oasis.oati.com/NWMT/NWMTdocs/ETP_Methodology,_Criteria_&_Process-BP_Final_Approved_6-10-18_Effective_6-15-18.pdf
2) PacifiCorp Engineering Handbook section 1B.4 - https://www.pacificpower.net/content/dam/pacific_power/doc/Contractors_Suppliers/Power_Quality_Standards/1B_4_PF.pdf

Link to NERC TPL Standards:

http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United

Link to WECC Regional Business Practice:

https://www.wecc.biz/Reliability/TPL-001-WECC-RBP-2.1.pdf

C. Methodology for Comparison of System Performance Reliability Results

The following methodology shall be applied for comparing the results of the Change Cases with the results from the cases of the Initial Regional Plan projects.

1. Alternative Projects

Each of the Change Cases will be evaluated for the study year using the same system performance criteria as is used for the cases with the Initial Regional Plan. The study results of these Change Cases will be compared against results from the studies using the Initial Regional Plan.

Case	B2H	Gateway S	Gateway W	Antelope Projects	SWIP N	Cross-Tie	TWE DC	TWE DC/AC	Stressed Conditions:
null									A B C D F
pRTP	X	X	a						A B C D F
iRTP	X	X	X	X					A B C D E F
CC1	X								A B C D F
CC2		X		X					A D E F
CC3		X	X						A C D E F
CC4	X		X	X					A C D E F
CC5								X	A B C D E F
CC6							X		A B C D F
CC7						X			A B C D F
CC8					X				A B C D F
CC9								X	E+RPS
CC10		X						X	E+RPS
CC11			X					X	E+RPS
CC12		X	X					X	E+RPS
CC13							X		E+RPS
CC14		X					X		E+RPS
CC15		X	X				X		E+RPS
CC16						X			E+RPS
CC17		X				X			E+RPS
CC18		X	X			X			E+RPS
CC19					X				E+RPS
CC20			X		X				E+RPS
CC21		X	X		X				E+RPS
CC22		X	X		X	X			E+RPS
CC23			X		X			X	E+RPS
CC24		X				X		X	E+RPS
CC25		X	X		X	X		X	E+RPS
CC26			X		X		X		E+RPS
CC27		X				X	X		E+RPS
CC28		X	X		X	X	X		E+RPS

	The change case does not include the non-Committed Project
X	The change case includes the non-Committed Project
a	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah
	The change case was run with and without B2H

Table 10 – Illustrative Change Case selection

Project Descriptions:

- B2H includes: Boardman to Hemingway, Hemingway to Bowmont and Bowmont to Hubbard
- Gateway South includes: Aeolus to Clover
- Gateway West includes: Windstar to Aeolus, Aeolus to Anticline, Anticline to Jim Bridger, Anticline to Populus, Populus to Borah, Populus to Cedar Hill, Cedar Hill to Hemingway, Cedar Hill to Midpoint and the Borah to Midpoint uprate
- Antelope Projects includes: Antelope to Goshen and Antelope to Borah
- SWIP N includes: Midpoint to Robinson Summit
- Cross Tie includes: Clover to Robinson Summit
- TWE includes: a line between Rawlins, WY and Boulder City, NV

Table 10 is a modified version of the prior cycle's Change Case table since conditions to be studied are similar to last cycle, however, the Change Case table is for illustrative purposes, and will be updated once the production cost model results have been run and a better understanding of the flow patterns is determined. It is impractical to run all combination of projects and all flow patterns, so TWG must use its professional judgement to identify the Change Cases to study. For example, for the seven groups of projects above, to study all combinations requires 128 different change cases. On top of the 128 change cases, there are likely 5 or so flow conditions to test. Utilizing professional judgment, the table above reflects some of the project combinations that could be analyzed as part of the Change Cases. Which change case is run on which flow pattern will be resolved in Quarter 3 and Quarter 7. TWG will provide updates to the Planning Committee on the continuing development of this table as the study progresses.

To develop the null case, TWG will take the 2028 production cost model and remove all significant future transmission facilities. The purpose of the null case is to test the NTTG footprint with the present (2018/2019) transmission system with 2028 future loads and resources.

The following analysis criterion will be used to determine if a Change Case is a more efficient or cost-effective solution for the NTTG footprint than the Initial Regional Plan:

a. System Performance Analysis

The Change Case must meet all system performance criteria defined above. The TWG will monitor system conditions in each of the created base cases to determine if they meet the system performance criteria. If not, modifications may be made to transmission facilities until the case meets the system performance criteria. A Change Case can be modified at the discretion of the TWG to meet such system performance criteria using unsponsored projects.

b. Capital Related Costs

The TWG will validate all project submitted costs with the WECC Transmission Capital Cost Calculator, an MS Excel spreadsheet. The TWG will enter the submitted project data into the

Calculator, adjusting (after consultation with the Project Sponsor if necessary) the project cost data for consistency and a common year assumption with the WECC data, and compare the submitted project capital costs to the Calculator output. If the submitted costs vary from the Calculator output by 20%, the TWG will contact the Project Sponsor and seek to resolve the cost difference. However, if the difference cannot be resolved, the TWG will determine the appropriate cost to apply in the study process.

A reduction in the annual capital related costs from the Initial Regional Plan to a Change Case captures the extent that Non-Committed Project(s) in the Initial Regional Plan can be displaced (either deferred or replaced) while still meeting all regional transmission needs and system performance requirements. The annual capital-related costs will be the sum of annual return (both debt and equity related), depreciation, taxes other than income, operation and maintenance expense, and income taxes. Power flow analysis will be used to ensure the Change Case meets transmission System Performance requirements.

c. Energy Losses

Production Cost Model software will be used to compare losses before and after a project is added to the system. . A reduction in losses after a project is added represents the benefit.

d. Reserves

The Reserves metric is treated as a capacity sharing opportunity between Balancing Areas, not a production cost problem. The analysis must evaluate a number of capacity sharing opportunities amongst various combinations of Balancing Areas. The reserve metric will be accessed on a Balancing Area basis and is based on the incremental load and generation submitted by the TPs. The future reserve requirements will be priced assuming a simple cycle Frame F unit. Energy cost for each calculated reserve event will be priced at the Balancing Area gas price used in the NTTG production cost base case. In order for a Reserve benefit to exist, there must be uncommitted transmission capacity available on the projects under evaluation. The calculation will be performed using a spreadsheet which will consider the savings between each Balancing Area providing its own incremental reserve requirement and a combination of balancing areas sharing a reserve resource facilitated by uncommitted transmission capacity.

2. Cost Allocation Analysis

The projects eligible for cost allocation consideration that are incorporated with the Draft Regional Transmission Plan will be evaluated for cost allocation by the Cost Allocation Committee. Those entities affected by a change in Capital-Related Costs, Energy Losses and Reserves, as defined above, shall be identified for use in the cost allocation process. NTTG will allocate the net benefits to TP's.

V. Robustness of Draft Regional Transmission Plan

The robustness analysis will provide information regarding the Draft Regional Transmission Plan's ability to reliably serve the transmission needs of an uncertain future. The Draft Regional Transmission Plan is developed using base assumptions (e.g., transmission topology, load level and generation dispatch patterns) of the 2028 ADS base case and modified to reflect desired stressed conditions. These base assumptions represent a pre-defined future that drives the 2028 transmission topology in the Draft Regional Transmission Plan. The robustness analysis will use power flow analysis and input from production cost analysis as needed to test whether or not the 2028 Draft Regional Transmission Plan transmission system performance will remain acceptable assuming deviations from the base case assumptions. The TWG will use its discretion to define the deviations from base case assumptions to test and may draw on assumptions used in change cases or allocation scenarios and will seek input from stakeholders through the Planning Committee.

VI. Cost Allocation Scenarios

Introduction

The Cost Allocation Committee ("CAC") applies a regional cost allocation methodology for the purpose of allocating the costs of regional and interregional transmission projects that the Planning Committee selects into the Regional Transmission Plan for purposes of regional cost allocation. In the case of interregional projects, this means NTTG's allocated portion of the interregional project's costs. The purpose of this portion of the study plan is to describe the allocation scenarios that were developed by the Cost Allocation Committee, in consultation with the Planning Committee, and with stakeholder input. The allocation scenarios are intended to represent potential alternate futures of the Regional Transmission Plan by varying parameters that likely affect the amount of total benefits of a project, their distribution among Beneficiaries, and to assess whether or not the Regional Transmission Plan is robust enough to meet the reliability requirements. The allocation scenario analyses will determine the benefits and Beneficiaries of the Regional Transmission Plan[20] to be compared with the benefits and Beneficiaries of the four allocation scenarios. The analyses will produce five sets of benefit and Beneficiary differences - the benefits and Beneficiaries difference between the Initial Regional Transmission Plan and the Draft Regional Transmission Plan and the benefits and Beneficiaries differences between the Initial Regional Transmission Plan and each of the four cost allocation scenarios. Costs will be allocated if the benefits outweigh the costs of the project or scenario.

During NTTG's biennial planning cycle, NTTG's Regional Transmission Plan is developed in draft form at the end of the Quarter 4 technical analysis and updated, if appropriate, after the

[20] Throughout the planning cycle the Regional Transmission Plan will be represented by the Draft Regional Transmission Plan or Draft Final Regional Transmission Plan.

Quarter 5 data submittal period. Through the TWG technical analyses, the projects that have requested cost allocation and have been selected into the Regional Transmission Plan will receive cost allocation.

Pre-Qualification for Cost Allocation

Non-incumbent and Incumbent Transmission Developers intending to submit a project for cost allocation consideration must satisfy NTTG's project sponsor pre-qualification requirements by submitting the Project Sponsor Pre-Qualification Data form to info@nttg.biz by October 31, 2017. Project Sponsors must resubmit the project sponsor prequalification data in Quarter 8 of each succeeding cycle to demonstrate that they remain qualified to be considered a Sponsored Project in subsequent Regional Transmission Plans.

NTTG received two requests from Project Sponsors seeking to be pre-qualified. Unless one and/or both projects are selected, or the Planning Committee identifies and selects an unsponsored Alternative Project as a more efficient or cost effective solution during the development of in NTTG's Regional Transmission Plan, cost allocation will not be performed during this planning cycle.

Allocation Scenario Change Cases

The allocation scenarios results are derived from the Regional Transmission Plan. Thus, the Regional Transmission Plan is the basis for creating the allocation scenario Change Cases. A change in the benefits and allocation to Beneficiaries from the Initial Regional Plan to each allocation scenario Change Case is estimated as the difference between the Initial Regional Transmission Plan benefits and Beneficiaries and the allocation scenario Change Case benefits and Beneficiaries.

Allocation Scenarios

The Cost Allocation Committee, in consultation with the Planning Committee and with stakeholder input, will create allocation scenarios for those parameters that likely affect the amount of total benefits of a project and their distribution among Beneficiaries. This process will provide the overall range of future cost allocation scenarios that will be used in determining a project's benefits and Beneficiaries. The variables in the allocation scenarios will include, but are not limited to, load levels by load-serving entity and geographic location, fuel prices, and fuel and resource availability. The purpose of the scenarios is not to stress the system in cost allocation, but to define reasonable alternative scenarios for the Regional Transmission Plan that represent a legitimate alternative view of the future.

The following allocation scenarios were developed by the Cost Allocation Committee, in consultation with the Planning Committee and with stakeholder input. See Attachment 4 for additional detail on the cost allocation scenarios development.

High and Low Load Allocation Assumptions:

Load forecasting is uncertain. The following allocation scenarios test the effects of load forecast uncertainty on the amount of total benefits and their distribution among Beneficiaries in with the Regional Transmission Plan.

A. High Load - Assumes the 2028 load forecast in the Regional Transmission Plan is too low: Add 1,000 MW of load in the NTTG footprint for a high load scenario. Allocate the 1,000 MW to each Balancing Authority Area ("BAA") based on historical BAA actual peak demand and projected 2028 BAA peak demand.

B. Low Load- Assumes the 2028 load forecast in the Regional Transmission Plan is too high: Subtract 1,000 MW of load in the NTTG footprint for a low load scenario. Allocate the 1,000 MW to each BAA based on historical BAA actual peak demand and projected 2028 BAA peak demand.

Resource Location and Type Allocation Scenario Assumptions:

Identifying the location and type of future resource is uncertain. The following allocation scenarios tests the future resource mix uncertainty for wind, solar and coal resources types and their location against the total benefits and their distribution among Beneficiaries within the Regional Transmission Plan.

C. Wind Replaced with Solar - Assumes a shift in type and location of future renewable resource away from wind to solar resources assumed in the Regional Transmission Plan: Remove 800 MW of new wind capacity from the 2028 generation resource data and replace with 800 MW of new solar capacity. The geographical location and quantity of solar capacity added will be based on each BAA's share of new solar resources added between 2018 and 2028 and that are placed on a regionally significant higher voltage system. This recognizes the regional and/or interregional nature of the transmission project so that system conditions are defined to get the most out of the scenario.

D. Coal Replaced by Wind and Solar - Assumes a replacement of some of the existing 2028 coal resources with wind and solar resources in different locations than assumed in the Regional Transmission Plan:
Remove 1,000 MW of coal and presume units that are not retired in the 2028 forecast can be reduced pro rata and replaced with equivalent capacity consistent with

transmission capability in equal shares of wind and solar in the appropriate geographic locations.

Cost Allocation Scenario Sensitivity Case:

In addition to the above four allocation scenarios, the Cost Allocation Committee requests that a Cost Allocation Scenario Sensitivity Case ("Sensitivity Case") be developed and studied by the TWG. This Sensitivity Case will provide information regarding the impact that the 2029 coal retirements may have on the distribution of benefits and beneficiaries identified in Cost Allocation Scenario D above. The Cost Allocation Committee requests that it be developed with the following assumptions:

A. Start with the Planning Committee's 2029 coal retirement sensitivity case.
The CAC understands that the 2029 coal retirement Sensitivity case will be considered to reflect the planned retirements and replacement energy resources that would occur immediately following the ten-year next planning horizon (detailed in Table 3) to ensure that unnecessary transmission would not be recommended in the RTP for a short-term change in resources levels.

B. Apply the Cost Allocation Scenario D assumptions defined above to the 2029 coal retirement sensitivity case described in 1.

C. Complete a power-flow study and compute the three cost allocation metrics in a manner that is consistent with the other cost allocation scenarios.

D. Further, the Cost Allocation Committee recognizes this sensitivity case will completed only if the TWG has the time and resources to do so.

Power Flow Analysis

The transmission reliability for the allocation scenarios will be analyzed using power flow analysis at a minimum. The power flow analysis will be an N-0 and limited N-1 study to create solved cases that may include thermal or voltage reliability issues. If mitigation is required to meet reliability criteria, these will be identified, including an estimate of the capital cost for the mitigation. If after study, a future uncommitted transmission project is not needed because of the allocation scenario assumptions, then for the purposes of this allocation scenario, the uncommitted transmission project and its costs may be deferred beyond the 10-year planning horizon with appropriate capital cost adjustments.

Benefits and Beneficiary Analysis

The three economic metrics that will be used by the TWG to define benefits and Beneficiaries for the allocation scenarios are capital costs, line losses and reserve margin. Each metric will be expressed as an annual change in costs (or revenue) and provided to the CAC. A common year will be selected for net present value calculations for all cases to enable a comparative analysis between each allocation scenario Change Cases and the Initial Regional Transmission Plan (iRTP), as adjusted for updated Quarter 5 load and resource data. The following describes each metric and the calculation of its benefit.

A) Capital Cost Benefit - The capital cost benefit will be computed from the annual capital-related costs[21] for each Transmission Provider. The difference between the iRTP incremental capital cost and the Regional Transmission Plan (or allocation scenario) capital cost computes the benefit related to the Regional Transmission Plan (or an allocation scenario). This difference will provide the capital cost benefit. The beneficiaries will be defined from the TWG technical analysis and may be any entity, including, but not limited to, transmission providers (both incumbent and non-incumbent), Merchant Transmission Developers, load serving entities, transmission customers or generators that utilize the regional transmission system within the NTTG footprint to transmit energy or provide other energy-related services.
B) Line Loss Benefit - The line loss benefit is computed as a change in energy generated to serve a given amount of load. The change in estimated energy loss between the iRTP and the Regional Transmission Plan (or a cost allocation scenario) measures the line loss impact benefit of the Regional Transmission Plan or an allocation scenario. The line loss will be computed through power flow or production cost model analysis and monetized using an index price of power for each Transmission Provider. Again, the beneficiaries will be defined from the TWG technical analysis and may be any entity including, but not limited to, transmission providers (both incumbent and non-incumbent), Merchant Transmission Developers, load serving entities, transmission customers or generators that utilize the regional transmission system within the NTTG footprint to transmit energy or provide other energy-related services.
C) Reserve Margin Benefit - This metric is based on savings that may result when two or more Balancing Authority Areas could economically share a reserve resource when unused transmission capacity remains in a transmission project. The reserve margin metric will be computed through spreadsheet analysis and monetized using an index price of power for each Balancing Authority Area and measures the benefit of the Alternative Project in the Draft Final Regional Transmission Plan (“DFRTP”) (or a cost allocation scenario). The beneficiaries are the Balancing Authority Areas.

Cost Allocation Committee

The TWG will provide the benefit information calculated above to the CAC to be used in the cost allocation process.

[21] Annual capital-related costs will be the sum of annual return (both debt and equity related), depreciation, taxes other than income, operation and maintenance expense, and income taxes.

VII. Impacts on Neighboring Regions

The iRTP and Change Case Plan(s) power flow studies will monitor the BES voltage and thermal loading in NTTG's neighboring planning regions: ColumbiaGrid, WestConnect, and CAISO. These power flow studies will identify any BES thermal and voltage violations using NERC criteria unless a neighboring planning region provides alternative criteria. Should a BES violation be observed in the neighboring region, either in the iRTP or the Change Case Plan(s), the TWG will coordinate with the affected planning region to verify that the study results are valid and that this a new violation and is not a pre-existing problem that the affected planning region should mitigate. If there is a new violation caused by the iRTP or Change Case plan, the TWG will endeavor to alleviate the violation using acceptable mitigation options within the NTTG footprint. If the violation in the neighboring planning region cannot be eliminated (i.e., the thermal and/or voltage are not within acceptable planning criteria) after all reasonable NTTG internal mitigation measures have been studied, then the TWG will again coordinate with the impacted planning region to determine if that region will ameliorate the violation through mitigation measures within the affected planning region at its expense. If the answer is no, the iRTP or Change Case Plan will be eliminated from possible consideration as a plan that is more efficient or cost effective. Should the violations remain after all options for alleviation, both within the NTTG footprint and within the affected region, have been exhausted, then the Change Case or iRTP will not be selected for the Draft Regional Plan.

Mitigation costs incurred as a result of changes made to facilities inside the NTTG footprint that eliminate the thermal or voltage violations observed in neighboring planning region(s) will be quantified and added to the cost of the plan under study when selecting a project for the Draft Regional Transmission Plan.

VIII. Interregional Coordination and evaluation of Interregional Transmission Projects

Evaluation of a properly submitted ITP will be in the context of the ITP joint evaluation plan and NTTG's regional planning process as an Alternative Project.

As part of the interregional coordination, NTTG and the other regional entities in the western interconnection will collaborate during their transmission planning processes to ensure regional transmission stability and efficiency. These coordination efforts inform each planning regions' transmission plans. An annual Interregional Coordination Meeting (ICM) was held on February 22nd, 2018 to discuss and begin to coordinate regional planning data and information. Prior to the annual ICM, NTTG posted on its website the following information:

(i) NTTG's prior cycle's Regional Transmission Plan, and
(ii) NTTG's prior cycle Biennial Study Plan

At the Annual Interregional Coordination Meeting, stakeholders discussed conceptual solutions and potential proponents of ITPs were reminded to submit the projects to the applicable regions by March 31st.

For each ITP that is properly submitted, NTTG will confer with and will seek to coordinate planning data and ITP study assumptions with the other Relevant Planning Region(s) regarding the following:

(i) ITP data and projected ITP costs; and
(ii) the study assumptions and methodologies it is to use in evaluating the ITP pursuant to its regional transmission planning process.

For each ITP that is properly submitted, NTTG will:

a. seek to resolve any differences it has with the other Relevant Planning Regions relating to the ITP or to information specific to other Relevant Planning Regions insofar as such differences may affect NTTG's evaluation of the ITP;
b. provide stakeholders an opportunity to participate in NTTG's activities in accordance with its regional transmission planning process;
c. notify the other Relevant Planning Regions if NTTG determines that the ITP will not meet any of its regional transmission needs; thereafter NTTG has no obligation to participate in the joint evaluation of the ITP; and
d. determine under its regional transmission planning process if such ITP is a more cost effective or efficient solution to one or more of NTTG's regional transmission needs.

The Interregional Transmission Project coordination timeline is included as Attachment 5. Significant events in that timeline are the Interregional Coordination meeting held in February, the project submittal deadline to the relevant regions and the region's developing agreed upon common study assumptions, data, methodologies, cost assumptions and a schedule for determining the selection of an ITP into a regions' Transmission Plan.

A properly submitted ITP will be evaluated as an Alternative Project in NTTG's regional planning process. The set of Non-Committed Projects (regional and/or interregional) that result in the more efficient or cost effective regional transmission plan will be included in NTTG's Draft (or Draft Final, Revised Draft Finial or Final) Regional Transmission Plan. See section IV.A.3 for additional information regarding NTTG regional planning process. Stakeholders are welcome and encouraged to be involved and participate in NTTG's regional Planning Committee meetings and Quarterly Stakeholder meetings.

IX. Requests for Public Policy Considerations

Public Policy Considerations are those relevant factors that are not established by local, state, or federal laws or regulations.

Public Policy Considerations will be separate scenario analysis or sensitivity cases. The results of the analysis may inform the Regional Transmission Plan, but will not result in the inclusion of additional projects in the Regional Transmission Plan.

A Public Policy Consideration (PPC) request was submitted to NTTG 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. A Study Plan was prepared by the Technical Workgroup in consultation with the Joint Submitters and included as Attachment 3.

X. Draft Regional Transmission Plan

The Planning Committee shall produce a Draft Regional Transmission Plan by the end of Quarter 4. The projects selected into the Draft Regional Transmission Plan are determined according to the study methodology in this document, and the projects selected into the Draft Regional Transmission Plan for cost allocation are determined according to the Cost Allocation process described above.

Attachment 1
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:

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
IPC	**Idaho**	No RPS Requirement					
Northwestern	**Montana**	Utilities-IOUs; Retail supplier Applies to: NWE	Wind Solar electric Geothermal Biomass *Wood, treated (SB 325 2013)* Landfill gas Anaerobic dig. Hydro (existing 10 MW or less; 15 MW new after Apr. 2009; *expansion of existing dam capacity (SB 45 2013)* Fuel Cells (RE)	2008-09 5% 2010-14 10% 2015+ 15%		Utilities must purchase RECs & output of community projects 50 MW in 2010-14 and 75 MW in 2015+	Includes cost caps utilities must pay on RE
PacifiCorp	**California**	Utilities -- IOUs; POUs Electric service providers; Community choice aggregators	Solar electric; Wind; Geothermal; Biomass; Landfill gas; MSW; Anaerobic dig.; Small Hydro (30MW or less); Tidal, wave, ocean thermal; Fuel Cells-RE	2013-Dec 20% 2016-Dec 25% 2020-Dec 33% 2030-Dec 50% SBX1-2 approved Apr. 2011 In April 2015, Governor Brown	Product Category % Allocation: Contracts executed after June 2010 and in 3rd compliance period (2017 forward): Category (1):75% interconnected to grid within, scheduled for direct delivery into or dynamically transferred to CA Category(2): 0-25% firmed and shaped, scheduled into CA BA		

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
				issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously-established 2050 target.	Category (3): 0-10% other/unbundled RECs		
	Oregon	<u>Large Utilities</u> - - selling more than 3% of retail electricity in OR Applies to: PGE, PacifiCorp, and Eugene Water	"Qualifying electricity" Electricity generated by facility operational on or after Jan. 1, 1995, except if: Non-hydro facility before 1995 upgraded, or Hydro facility upgraded on or after 1995 "Renewable energy" a) Wind; b) Solar PV or thermal;	5% by 2011 15% by 2015 20% by 2020 25% by 2025 50% by 2040 On March 8, 2016, Governor Kate Brown signed Senate Bill 1547-B (SB 1547-			If costs to consumer increase more than 4%, utilities do not have to comply with RPS

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
		& Electric Board	c) Wave, tidal, ocean energy; d) Geothermal e) Biomass (specified types) Hydrogen-RE Resource must be operational on or after 1995	B), the Clean Electricity and Coal Transition Plan, into law. Senate Bill 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged: 27% by 2025, 35% by 2030, 45% by 2035 and 50% by 2040.			
	Utah	Applicable to IOUs, Municipals, and Coops	Wind, solar, biomass, geothermal, hydro under conditions, wave or tidal	Renewable Portfolio Goal: 20% by 2025 No interim requirements, first			

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
		Applies to PacifiCorp (Rocky Mtn Power), UAMPS, UMPA, Deseret Power		compliance year are 2025. Applies to "adjusted retailed sales" (=sales less power from nuclear, effective" demand-side mgt, fossil fuel with CCS) Utilities must pursue renewables to the extent that it is "cost			
	Washington	Utilities serving more than 25,000 customers; Based on Form 861 filed with EIA Of WA's 62 utilities, applies to 17 utilities that make up about 84% of the WA load.	Renewable resource: a) Water b) Wind; c) Solar energy; d) Geothermal; e) Landfill gas; f) wave, ocean or tidal; g) gas from sewage; h) Biodiesel; i) Biomass (animal waste, organic fuels from wood, forest or field residue, and dedicated energy crops "Eligible renewable resource" – a) Located in Pacific Northwest; Electricity delivered into WA on real-time basis without shaping, storage, or integration services;	2012-15 3% 2016-19 9% 2020+ 15% Energy efficiency (EE) requirements: (1) By 2010 must identify achievable cost-effective potential thru 2019; (2) Meet biennial EE targets.	Distributed generation = 200% credit, if utility owns facility, contracted for DG and RECs, or contracted to purchase RECs.	"Eligible renewable resource" – a) Located in Pacific Northwest; Electricity delivered into WA on real-time basis without shaping, storage, or integration services;	

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
			b) Hydropower result of efficiency improvements completed after March 31, 1999 in PNW, or hydro generation in irrigation pipes				
	Wyoming	No RPS Requirement					
PGE	**Oregon**	See Oregon above.					

Attachment 2
Simultaneous Wyoming Wind Production:

TWG will review the hourly simultaneous production of the wind resources in the ADS PCM case. Figure 1 shows a peak duration curve of those expected resources based on data developed by NREL for the 2009 weather patterns. 2009 is the year selected by WECC to base all the hourly profiles for load, average hydro conditions and fixed/non-dispatchable generation. TWG reviewed the duration curve in Figure 1 and selected a study level of 2860 MW or approximately 90% 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 960 hours or over a month. At this level, based on the assumed wind production levels from the new wind profiles, the "must-take" nature of the wind output in the model and the assumption that all other resources forecasted to be in-service in the Wyoming area remain at typical high output is feasible. The time of year, time of day and the associated load level of the high wind scenario will also reflective of the most likely occurrence of the high wind scenario as indicated in Figure 1.

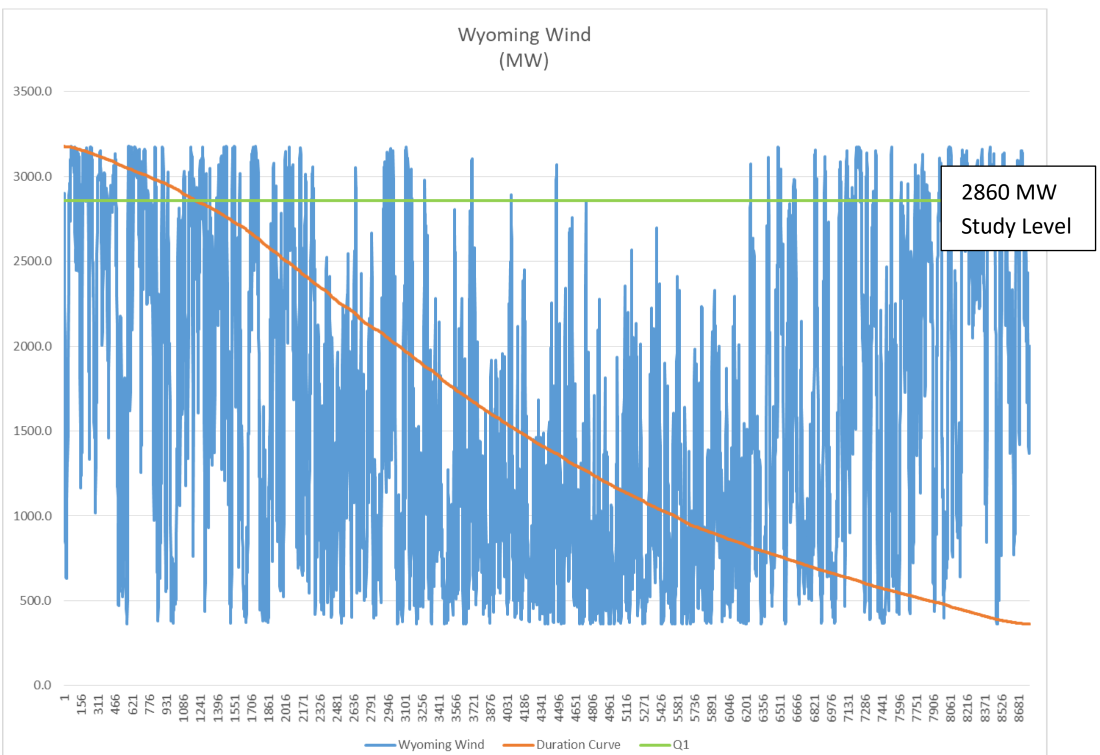


Figure 1: Chronologic and Duration curve of forecasted Wyoming wind production for 2028

Attachment 3
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:

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

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 4
Cost Allocation Scenario Development

Recommended by the Cost Allocation Committee on May 2, 2018

The Cost Allocation Committee, in consultation with the Planning Committee and with stakeholder input, will create cost allocation scenarios for those parameters that likely affect the amount of total benefits of a project and their distribution among Beneficiaries. This process will provide an overall range of future cost allocation scenarios to be used in determining a project's benefits and Beneficiaries. The variables in the allocation scenarios may include, but are not limited to, load levels by load-serving entity and geographic location, fuel prices, and fuel and resource availability.

The purpose of the allocation scenarios is not to stress the system for cost allocation, but to define reasonable alternative scenarios for the Regional Transmission Plan that represent a legitimate alternative view of the future.

Load Forecast Allocation Scenarios

Table 1 displays historical peak load data and the forecast 2028 peak load received from transmission providers in response to NTTG's Quarter 1 2018 data request.

2028 Peak Load Data — June 7, 2018

	Actual Peak MW					Q1 2018	Compound Growth Rate	
	2013	2014	2015	2016	2017	2028	2013-->2017	2017-->2028
IPC	3,774	3,550	3,765	3,657	3,806	4,412	0.21%	1.35%
NWE	1,707	1,748	1,790	1,801	1,821	2,027	1.63%	0.98%
PACE *	7,495	7,422	9,134	8,487		9,697		
PACW *	3,012	2,892	3,500	3,611		3,689		
PAC Ttl *	10,507	10,314	12,634	12,098	12,634	13,386	4.72%	0.53%
PGE	3,900	3,899	3,958	3,706	4,023	3,928	0.78%	-0.22%
NTTG	19,888	19,511	22,147	21,262	22,284	23,753	5.53%	0.58%

* The MW provided for 2013, 2014, and 2015 are representative of PacifiCorp load only as was the 714 reporting practice during those years. 2016 MW are representative of the total combined BA load per current

Table 1

Load forecasting is uncertain. The load forecast allocation scenarios are to test the effects of load forecast uncertainty on the amount of total benefits and their distribution among Beneficiaries in the Regional Transmission Plan. The following high and low load forecast allocation scenarios are developed for that purpose.

A. High Load - Assumes the 2028 load forecast in the Regional Transmission Plan is too low:

Add 1,000 MW of load in the NTTG footprint for a high load scenario. Allocate the 1,000 MW to each Balancing Authority Area ("BAA") based on historical BAA actual peak demand and projected 2028 BAA peak demand.

B. Low Load- Assumes the 2028 load forecast in the Regional Transmission Plan is too high:

Subtract 1,000 MW of load in the NTTG footprint for a low load scenario. Allocate the 1,000 MW to each BAA based on historical BAA actual peak demand and projected 2028 BAA peak demand.

Change Case Allocation Scenario Assumptions

The 2028 peak load forecast for each company is to be adjusted by plus or minus 1,000 MW. The prorated percent shown in Table 2 for each company is derived using the actual and 2028 forecast peak load data in Table 1.

2018-19 Allocation Scenarios A and B: High and Low Load Forecasts

June 7, 2018

					Cost Allocation	
	Forecast 2028	Prorrated Percent *	Allocation Scn Adj 1000	-1000	Scenario A	Scenario B
IPC	4,412	17.8%	178	-178	4,590	4,234
NWE	2,027	8.5%	85	-85	2,112	1,942
PACE	9,697	39.3%	393	-393	10,090	9,304
PACW	3,689	15.7%	157	-157	3,846	3,532
PGE	3,928	18.7%	187	-187	4,115	3,741
NTTG	23,753	100.0%	1,000	-1,000	24,753	22,753

* Prorated % Weight = ∑Company(2013 … 2016, 2028) / ∑NTTG(2013 … 2016,2028)

Table 2

Table 2 uses both the 2013 through 2016 actual data and the PCM 2028 forecast peak data from Table 1 to develop a prorated (i.e., weighted) percent that is used to allocate the plus or minus 1,000 MW to each of the BAAs.

SANITY CHECK

A sanity check was conducted to determine whether or not the plus and minus 1,000 MW variance from the base case is a reasonable assumption. Table 3 shows the results of this sanity check. As can be seen in Table 3, the plus or minus 1,000 MW is approximately half the base case load forecast differences. A review of prior utility Integrated Resource Plans found the low and high load forecasts varied about 7% lower and higher than the base case forecast. Therefore, this sanity check concludes that the plus and minus 1,000 MW is a reasonable estimate to use for the low load and high load cost allocation scenarios.

2028 High & Low Peak Load Forecast Estimates						June 7, 2018
	PAC	IPC	NWE	PGE	NTTG	Difference
Low Forecast *	12,047	3,971	1,824	3,535	21,378	-2,375
Base Forecast	13,386	4,412	2,027	3,928	23,753	0
High Forecast *	14,725	4,853	2,230	4,321	26,128	2,375
* Low & High esimates developed as a 10% variance from the Base Case						

Table 3

Resource Location and Type Allocation Scenarios

Identifying the location and type of future resources is uncertain. The following allocation scenarios test the future resource mix uncertainty for wind, solar and coal resource types and their location against the total benefits and their distribution among Beneficiaries within the Regional Transmission Plan.

REPLACE 800 MW WIND WITH 800 MW SOLAR

C. Wind Replaced with Solar – This allocation scenario assumes a shift in type and location of future renewable resources away from wind to solar resources assumed in the Regional Transmission Plan.

Remove 800 MW of new wind capacity from the 2028 generation resource data and replace it with 800 MW of new solar capacity. The geographical location and quantity of solar capacity added will be based on each BAA's share of new solar resources added between 2018 and 2028 and that are placed on a regionally significant higher voltage system. This recognizes the regional and/or interregional nature of the transmission project so that system conditions are defined to get the most out of the scenario.

This allocation scenario shown in Table 4 assumes 800 MW of future wind from the high wind penetration areas is replaced with new solar in high penetration solar areas. The individual amounts of the 800 MW of future wind to remove from each BAA was computed as its percent of NTTG's new

2018-19 Allocation Scenario C: Replace 800 MW Wind with 800 MW Solar						
						April 17, 2018
	Wind			Solar		
	2018 to 2028 Δ Wind	Prorate MW * -800	Adjusted 2028	2018 to 2028 Δ Solar	Prorate MW ** 800	Adjusted 2028
IPC	0	0	0	24	30	54
NWE	786	-263	523	80	102	182
PACW	60	-20	40	243	309	552
PACE	1,542	-517	1,025	283	359	642
PGE	0	0	0	0	0	0
Total	2,388	-800	1,588	630	800	1,430
* Prorated MW = -800 MW * Company Δ Wind / NTTG Total Δ Wind						
** Prorated MW = 800 MW * Company Δ Solar / NTTG Total Δ Solar						

Table 4

incremental wind. Likewise, the addition of new future solar was computed as its percent of NTTG's new incremental wind in 2028.

REPLACE 1000 MW COAL REDUCTION WITH EQUAL SHARES OF WIND AND SOLAR

The next allocation scenario presumes 1,000 MW of coal units that are not retired in the 2028 case can be reduced pro rata from the BAAs with existing coal resources. The coal retirement assumptions within this scenario are made by NTTG Cost Allocation Committee and do not reflect actual or specific assumptions in any specific utility Integrated Resource Plans

D. Coal Replaced by Wind and Solar - Assumes a replacement of some of the existing 2028 coal resources with wind and solar resources in different locations than assumed in the Regional Transmission Plan.

Remove 1,000 MW of coal and presume units that are not retired in the 2028 forecast can be reduced pro rata and replaced with equivalent capacity consistent with transmission capability in equal shares of wind and solar in the appropriate geographic locations.

	Allocation Scenario D: Replace Coal with Wind and Solar					
	June 7, 2018					
				Scenario D		
		2028 Coal		2018 to 2028 Incremental MW		
1		Includes Retirements through 2028		Δ Solar		Δ Wind
2	IPC	0		24		0
3	NWE	1,480		80		786
4	PACW	0		243		60
5	PACE	7,039		283		1542
6	PGE	0		0		0
7	NTTG	8,519		630		2,388
8						
9	Adjustment					
10	NTTG MW Adj	-1,000		500		500
11						
12	MW Adjustment *	Coal		Solar		Wind
13	IPC	0		19		0
14	NWE	-174		63		165
15	PACW	0		193		13
16	PACE	-826		225		323
17	PGE	0		0		0
18	NTTG	-1,000		500		500
19						
20		Scenario D 2018 to 2028 Incremental MW				
21	2028 Adjusted BA MW	Coal		Adj Δ Solar		Adj Δ Wind
22	IPC	0		43		0
23	NWE	1,306		143		951
24	PACW	0		436		73
25	PACE	6,212		508		1,865
26	PGE	0		0		0
27	NTTG	7,519		1,130		2,888
	* BA MW Adjustment = NTTG MW Adj * (BA 2028 MW / NTTG 2028 MW)					

Table 5

This scenario removes 1,000 MW of existing 2028 coal resources and replaces the capacity lost from the coal with 500 MW of new wind and solar. See Table 5 below. It is assumed that the BAAs where the new wind and solar is added in 2028 will be located in the same geographic location as the replacement incremental solar and wind locations.

The allocation will be done on a prorated basis (rows 13-17, Table 5). The 2028 coal reduction of 1,000 MW (line 10) changes the 2028 forecast from 8,519 MW (row 7) to 7,519 MW (row 27). With this change, the 2028 adjusted solar and wind MW is 1,130 MW and 2,888 MW, respectively (row 27).

Cost Allocation Sensitivity Case

In addition to the above four allocation scenarios, the Cost Allocation Committee requests that a Cost Allocation Sensitivity Case ("Sensitivity Case") be developed and studied by the Technical Work Group ("TWG"). This Sensitivity Case will provide information regarding the effect that the 2029 coal retirements may have on the distribution of benefits and beneficiaries identified in Cost Allocation Scenario D above. The Cost Allocation Committee's request is contingent upon approval of the Planning Committee to develop a 2029 coal retirement sensitivity case. If the Planning Committee does not approve the 2029 coal retirement sensitivity case, the Cost Allocation Committee withdraws this request. If the sensitivity case is approved, the Cost Allocation Committee requests that it be developed with the following assumptions:

1. Start with the Planning Committee's 2029 coal retirement sensitivity case.
    a. The CAC understands that the 2029 coal retirement sensitivity case will be considered to reflect the planned retirements and replacement energy resources that would occur immediately following the ten-year next planning horizon (detailed in Table 3) to ensure that unnecessary transmission would not be recommended in the RTP for a short-term change in resources levels
2. Apply the Cost Allocation Scenario D assumptions defined above to the 2029 coal retirement sensitivity case described in 1.
3. Complete a power-flow study and compute the three cost allocation metrics in a manner that is consistent with the other cost allocation scenarios.
4. Further, the Cost Allocation Committee recognizes that this Sensitivity Case will be completed only if the TWG has the time and resources to do so.

Attachment 5
Interregional Transmission Project Coordination Timeline

The following table provides a proposed timeline[1] for such joint evaluation of an Interregional Transmission Project.

Objective	Target Date	Target
1. Distribute and post Meeting Notification to Stakeholders	January 8, 2018	45 days prior to Annual Coordination Meeting
2. Post and share Annual Interregional Information	February 1, 2018	21 days prior to the Annual Coordination Meeting
3. Engage in discussions about how shared information (regional needs) will be presented	February 5 thru February 17, 2018	After posting of the Annual Interregional Information and prior to posting the Annual Coordination Meeting materials
4. Post meeting agenda and presentation materials	February 15	7 days prior to the Annual Coordination Meeting
5. 2018 Annual Coordination Meeting – CAISO Hosts in Folsom	February 22, 2018	Sometime between February 1st and March 31st
6. ITP Submittal Deadline	March 31, 2018	The common ITP Submittal deadline for all Regions is no later than March 31 of every even numbered calendar year
7. Notify applicable Planning Regions of need to confer on any ITP proposals that may have been submitted	April 6, 2018	No less than 7 days following the ITP submittal deadline of March 31 of an even numbered calendar year
8. Resolve ITP data submittal deficiencies, if any	Per each region's process	Each region will follow its regional process and notify the other planning regions if deficiencies are not resolved

[1] This document is for discussion purposes only and does not supplement or modify any procedure or process contained in any entity's filed OATT (including Attachment K to such tariff) or other filed rate schedule. To the extent that anything herein is inconsistent with any entity's OATT or filed rate schedule, such OATT or other filed rate schedule shall control.

9.	Develop and post an ITP Evaluation Process Plan, including agreed to common study assumptions, data, methodologies, cost assumptions and a schedule for determining the selection of an ITP	June 14, 2018	No later than 75 days following the ITP submittal deadline
10.	Ongoing coordination of planning data and assumptions, including potential ITP benefits	Per ITP Evaluation Process Plan milestones	Per milestones, as may be developed and posted in the ITP Evaluation Process Plan, but not later than December 31 of each odd numbered calendar year
11.	2019 Annual Coordination Meeting – NTTG Hosts	February 21, 2019	Sometime between February 1st and March 31st
12.	Final determination of ITP selection[2]	Prior to December 31, 2019	Per the ITP Evaluation Process Plan, but no later than December 31, 2019

[2] Depending on each region's process, the completion of ITP determination may go beyond this date due to various factors such as re-evaluation process.

Attachment 6
Interregional Transmission Projects Evaluation Process Plans

ITP Evaluation Process Plan

SWIP-North

June 14, 2018

The goal of the coordinated Interregional Transmission Project (ITP) evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP. The joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP. The purpose of this document is to provide a common framework, coordinated by the Western Planning Regions, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan will be developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Region to which it was submitted.

ITP Submittal Summary

Project Submitted To:	California Independent System Operator ("California ISO"), Northern Tier Transmission Group ("NTTG") and WestConnect
Relevant Planning Regions[1]:	California ISO[2], NTTG and WestConnect
Cost Allocation Requested From:	California ISO[2], NTTG and WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

ITP Summary

Great Basin Transmission, LLC ("GBT"), an affiliate of LS Power, submitted the 275-mile northern portion of the Southwest Intertie Project (SWIP) to the California ISO and NTTG. SWIP-North was also submitted into WestConnect's planning process by the Western Energy Connection (WEC), LLC, a subsidiary of LS

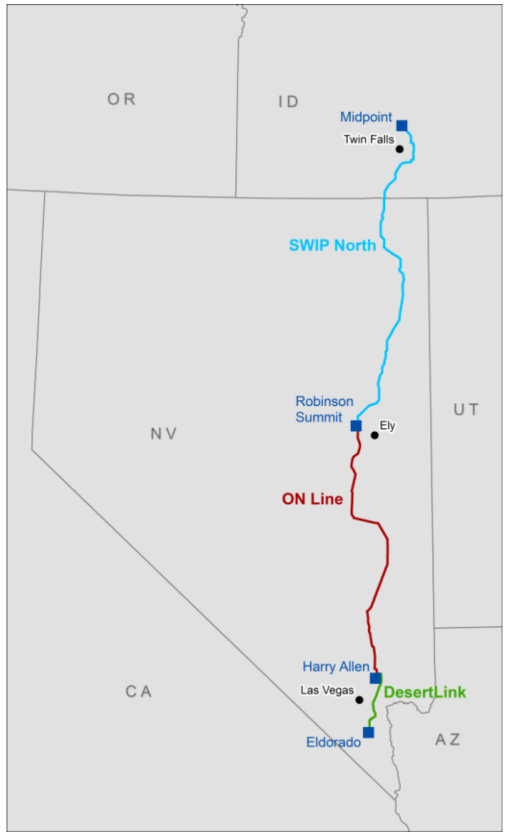
[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

[2] The California ISO has voluntarily agreed to study the SWIP-N line and accept cost allocation if the project is found to be needed by the California ISO and is ultimately constructed.

Power. The SWIP-North Project connects the Midpoint 500 kV substation (in NTTG) to the Robinson Summit 500 kV substation (in WestConnect) with a 500-kV single circuit AC transmission line. This portion of the project has been submitted for economic study as an Interregional Transmission Project with Cost Allocation. The SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. SWIP-North would require a new physical connection at Robinson Summit, but upon completion of SWIP-N a capacity sharing arrangement would be triggered between GBT and NV Energy across the already in-service ON-Line Project and SWIP-N that would provide GBT with control of ~1,000 MW capacity in both directions and include a contract path to California ISO at Harry Allen.

A federally approved route for SWIP-North has been secured by GBT through a right-of-way grant issued by the Department of the Interior’s Bureau of Land Management (“BLM”) along with an approved Construction, Operation & Maintenance Plan and conditional Notice to Proceed. All NEPA studies and decisions have been completed. Remaining key development activities include completing the WECC path rating process, securing a few remaining private easements, obtaining one local approval, and obtaining a permit to construct from the Public Utilities Commission of Nevada. If LS Power were selected to construct SWIP-North via cost allocation approved through the Interregional Transmission Process, development, final design and construction activities could be completed to support energization of the project within an estimated 36 months.

Figure 1: SWIP-N Map of Preliminary Route
Subject to change at discretion of proponent
(Source: SWIP-N ITP Submittal Attachment)



It is noted that in the event the Energy Gateway West project is built out by PacifiCorp, the northern terminus of SWIP-North could be either the existing Midpoint substation in Jerome County, Idaho, or the proposed new Cedar Hill substation approximately 34 miles south of Midpoint in Twin Falls County, Idaho.

ITP Evaluation By Relevant Planning Regions

NTTG has been identified as the Planning Region that will lead the coordination efforts with the other Planning Regions involved in the evaluation process. In this capacity, NTTG will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant

Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

Northern Tier Transmission Group

The NTTG Regional Transmission Plan evaluates whether transmission needs within the NTTG Footprint may be satisfied on a regional and interregional basis more efficiently or cost effectively than through local planning processes. While the NTTG Regional Transmission Plan is not a construction plan, it provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NTTG's 2018-2019 Regional Transmission Plan is to identify the Initial Regional Plan that includes NTTG's Funding Transmission Providers' local transmission plans and the uncommitted projects in NTTG 2016-2017 Regional Transmission Plan. NTTG then uses Change Cases to evaluate regional and interregional transmission projects that may produce a more efficient or cost effective regional transmission plan for NTTG's footprint. A Change Case is a scenario where one or more of the uncommitted transmission project(s) in the Initial Regional Plan will be added to, defer, or replace one or more of the other non-committed project(s) in the Initial Regional Plan.

The Initial Regional Plan and Change cases will be evaluated using power flow and dynamic analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. If the Change Case fails to meet these minimum reliability requirements, it will either be set aside as unacceptable or modified by the addition of another uncommitted project to ensure transmission reliability. The number of Change Cases will be determined through the technical planning process to carefully examine the reliability of and need for the non-committed regional and interregional projects to meet the region's transmission needs. The set of uncommitted projects, either from the Initial Regional Plan or a Change Case, that delineate the more efficient or cost-effective regional transmission plan, as measured economically by changes in capital related costs, losses and reserve margin, and adjusted by their effects on neighboring regions, will be selected into NTTG's Regional Transmission Plan. A more detailed discussion of NTTG's study process can be found in NTTG's Biennial Study Plan posted on NTTG's website.

WestConnect

WestConnect's 2018-19 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2018[3]. The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are being built and vetted during Q2 and Q3 of 2018. If regional needs are

[3] https://doc.westconnect.com/Documents.aspx?NID=18068&dl=1

identified during Q4 of 2018, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs and will determine which alternatives provide the more efficient or cost-effective solution. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan may go through the cost allocation process (if eligible).

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan and will not result in Order 1000 regional cost allocation. The WestConnect Planning Management Committee has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

SWIP-North representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2018-19 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs or opportunities that ultimately may lead to ITP project evaluations in 2019. Stakeholders are also encouraged to participate in the development of scenarios identified in WestConnect's 2018-19 Study Plan. These studies are also outlined in Figure 2.

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

Figure 2: WestConnect 2016-17 Transmission Assessment Summary

10-Year Base Cases (2028)	10-Year Scenarios (2028)
Heavy Summer (reliability) Light Spring (reliability) Base Case (economic)	Load Stress Study (reliability) California ISO Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy needs	Informational studies that may result in the identification of regional opportunities, alternative collection and evaluation is optional and is not subject to regional cost allocation

California ISO

The SWIP-North Project was submitted into the 2016-2017 interregional coordination cycle where the California ISO considered the proposed project in the context of California's 50% RPS goal where accessing out-of-state renewable resources for California was considered in the proposed project's assessment at a "high" or "cursory" level. The effort to perform an "informational" assessment of California procurement of out-of-state resources was concluded and documented in the 2017-2018 Transmission Plan[5].

California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO's planning process be obtained from within California. As such, the 2018-2019 planning process will consider the SWIP-North Project in the context of production cost simulation benefits such as congestion relief on COI and congestion costs on the COI/NOB scheduling interfaces. If the production cost analysis produces adequate economic benefits to proceed further with the analysis, then powerflow and stability analysis will be performed as well to consider possible benefits to contingency constraints on the bulk system in northern California.

The California ISO will develop the detailed modeling information for the GridView and GE PSLF computer programs and exchange that information with NTTG and WestConnect commensurate with existing data confidentiality requirements.

Data and Study Methodologies

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized the types of studies that will be conducted that are relevant to the SWIP-N evaluation in

[5] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 3: Relevant Planning Region Study Summary Matrix

Planning Study	NTTG	WestConnect	California ISO
Economic/Production Cost Model	Using the NTTG PCM Base Case, based on the WECC 2028 ADS Case, GridView will be used to conduct PCM analysis to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint	Regional Economic Assessment will be performed on WestConnect 2028 Base Case PCM (based on WECC 2028 2028 Anchor Data Set[6] (ADS)	Using the California ISO PCM Base Case, based on the WECC 2028 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect.
Reliability/Power Flow Assessment	The selected stressed hours will be transferred from GridView to the PowerWorld power flow model to conduct reliability analysis	Regional Reliability Assessment will be performed on 2028 Heavy Summer and Light Spring cases, [4]	Depending on the results of the production cost modeling, the GE PSLF may be used to perform steady state and as needed, transient analysis. The WECC 2028 ADS and 2028 LSP1 will be modified as needed to accurately model the California network and resources that reflects the ISO's finalized 2017-2018 transmission plan. The SWIP-North Project will be added to that model. All model information will be shared with NTTG and WestConnect.

[6] WestConnect's ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs, as a part of the 2018-2019 Base Case Transmission needs assessment.

Note that the SWIP-N evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC2028 Anchor Data Set (ADS) as the starting point data set for regional economic planning studies conducted in 2018 and 2019 (as applicable). Each Planning Region intends to update the 2028 ADS with their most recent and relevant regional planning assumptions to reflect its starting point transmission topology and generation data. The Planning Regions will strive to coordinate major updates made to the 2028 ADS as part of their regional model development efforts in late Q3, 2018.[7]

As an example, the California ISO will update the 2028 ADS to reflect their most recent Transmission Plan.[8] NTTG will ensure that its prior Regional Transmission Plan[9] is reflected. WestConnect will represent their current Base Transmission Plan,[10] and ColumbiaGrid will provide major updates to the 2028 ADS based on the information from the latest Biennial Plan[11] to other Planning Regions, subject to each region's applicable confidentiality agreement.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality agreements. The identification of the starting WECC power flow cases ("seed

[7] This schedule is dependent on the 2028 Anchor Data Set being provided by WECC no later than the end of Q2, 2018, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.
[8] California ISO 2017-2018 Transmission Plan
[9] NTTG 2016-2017 Regional Transmission Plan
[10] WestConnect 2018-2019 Base Transmission Plan
[11] ColumbiaGrid Update to the 2017 Biennial Transmission Plan

cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan.

Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the SWIP-N Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Relevant Planning Region's cost share of the SWIP-N Project will be calculated based on its share of the calculated benefits provided to the Region by the SWIP-N (as quantified per that Region's planning process).

The project cost data in the SWIP-N submittal form was marked as "Privileged information not to be released" and therefore has been redacted from this document.

Figure 4: Project Sponsor Cost Information[12]

Project Configuration	Cost ($)
Project level cost data	Redacted

After each Relevant Planning Region identifies their transmission needs and (as applicable) the benefits of the ITP, project costs for each Region to use in the determination of the more efficient or cost-effective alternatives for the region will be determined as follows:

Assumptions
Total Benefits ($) = NTTG Benefits ($) + WestConnect Benefits ($) +California ISO Benefits ($)
Project Cost ($) = Total capital cost of project, as agreed upon by Regions
Cost Calculations (for Planning Purposes)
NTTG Cost for Planning Purposes = [NTTG Benefits/Total Benefits] * Project Cost
WestConnect Cost for Planning Purposes = [WestConnect Benefits/Total Benefits] * Project Cost

[12] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

California ISO Cost for Planning Purposes = [California ISO Benefits/Total Benefits] *Project Cost

Note that this information on cost assumptions applies to costs that will be used for *planning evaluation purposes.* These costs may be different than what is assumed for any relevant cost allocation procedures.

Cost Allocation

Interregional Cost Allocation may apply for the SWIP-N Project for the 2018-2019 cycle.

GBT requested cost allocation from NTTG and the California ISO. WEC requested cost allocation from WestConnect. The project sponsor met the necessary requirements within the NTTG and WestConnect's respective Planning Region's regional processes to be considered eligible to request costs allocation if selected in either region's plan. The California ISO has voluntarily agreed to accept cost allocation if the project is found to be needed by the California ISO and ultimately constructed.

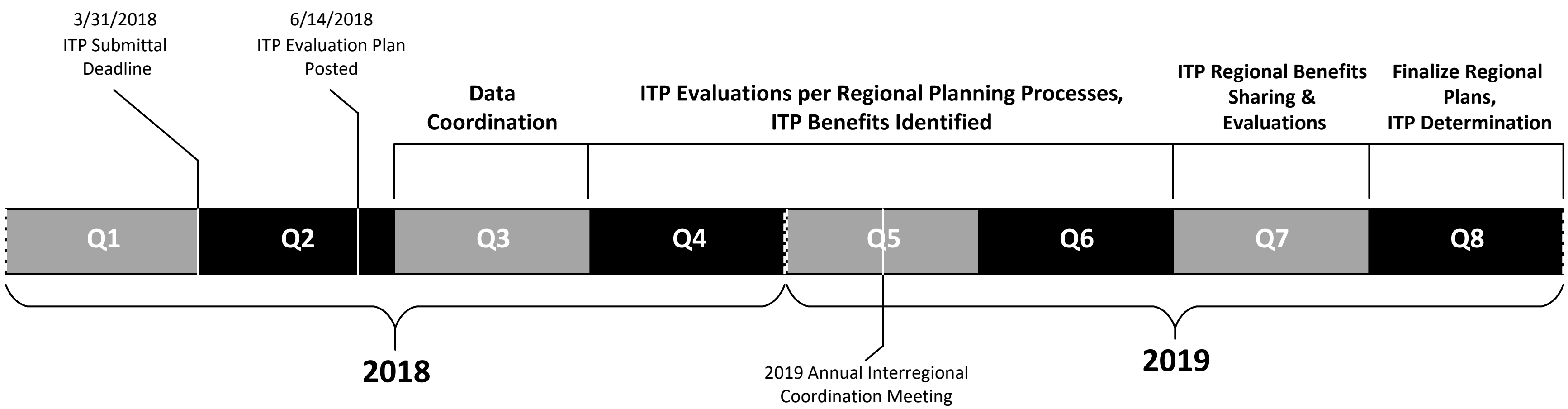
If at least two regions subsequently select the SWIP-North project in their respective regional transmission plans for purposes of Interregional Cost Allocation, each region will individually apply their regional cost allocation methodology to the projected costs of the SWIP-N Project assigned to each region in accordance with each region's regional cost allocation methodology. If only one of the Relevant Planning Regions for the SWIP-N Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the SWIP-N Project is reduced to one, the project will no longer be eligible for interregional cost allocation.

Schedule and Evaluation Milestones

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2018 and (as applicable) 2019. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP benefits.

Figure 5: ITP Evaluation Timeline



Contact Information

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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ITP Evaluation Process Plan

Cross-Tie Transmission Project

June 14, 2018

The goal of the coordinated Interregional Transmission Project (ITP) evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP. The joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP. The purpose of this document is to provide a common framework, coordinated by the Western Planning Regions, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan will be developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Region to which it was submitted.

ITP Submittal Summary

Project Submitted To:	California ISO, Northern Tier Transmission Group ("NTTG") and WestConnect
Relevant Planning Regions[1]:	NTTG and WestConnect[2]
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

[2] The California ISO has determined that it is not a Relevant Planning Region for the Cross-Tie Transmission Project.

ITP Summary

TransCanyon, LLC (TransCanyon) submitted the 213-mile Cross-Tie Transmission Project (Cross-Tie Project) for consideration as an Interregional Transmission Project. Cross-Tie is a proposed 1500 MW, 500 kV HVAC transmission project that will be constructed between central Utah and east-central Nevada (see Figure 1), connecting PacifiCorp's proposed 500-kV Clover substation (in the NTTG planning region) with NV Energy's existing 500 kV Robinson Summit substation (in the WestConnect planning region). The proposed project includes series compensation at both ends of the Cross-Tie transmission line. In addition, series compensation is needed on the existing Robinson Summit to Harry Allen 500-kV line along with phase shifting transformers at Robinson Summit 345-kV.

The project would be required to satisfy the requirements of the National Environmental Policy Act (NEPA) and the Bureau of Land Management (BLM). A significant portion of the routing of the line has been previously studied under the Southwest Intertie Project Environmental Impact Statement, which

received federal approval in a Record of Decision published in 1994 but was not constructed. Further, the project would be subject to the state approval processes applicable for Nevada and Utah. In any event, as the project is anticipated to follow existing transmission line corridors, TransCanyon believes that the risk of failing to obtain necessary administrative approval is considered minimal to moderate. According to TransCanyon, the project is expected to be in-service by 12/31/2024.

Figure 1: Cross-Tie Project Overview

{Subject to change based on Sponsor's review} (Source: TransCanyon 2018 ITP Submittal Attachment)

ITP Evaluation By Relevant Planning Regions

WestConnect has been identified as the Planning Region that will lead the coordination efforts with the other Relevant Planning Regions identified for the ITP. In this capacity, WestConnect will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

Northern Tier Transmission Group

The NTTG Regional Transmission Plan evaluates whether transmission needs within the NTTG Footprint may be satisfied on a regional and interregional basis more efficiently or cost effectively than through local planning processes. While the NTTG Regional Transmission Plan is not a construction plan, it provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NTTG's 2018-2019 Regional Transmission Plan is to identify the Initial Regional Plan that includes NTTG's Funding Transmission Providers' local transmission plans and the uncommitted projects in NTTG 2016-2017 Regional Transmission Plan. NTTG then uses Change Cases to evaluate regional and interregional transmission projects that may produce a more efficient or cost effective regional transmission plan for NTTG's footprint. A Change Case is a scenario where one or more of the uncommitted transmission project(s) in the Initial Regional Plan will be added to, defer, or replace one or more of the other non-committed project(s) in the Initial Regional Plan.

The Initial Regional Plan and Change cases will be evaluated using power flow and dynamic analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. If the Change Case fails to meet these minimum reliability requirements, it will either be set aside as unacceptable or modified by the addition of another uncommitted project to ensure transmission reliability. The number of Change Cases will be determined through the technical planning process so as to carefully examine the reliability of and need for the non- committed regional and interregional projects to meet the regions transmission needs. The set of uncommitted projects, either from the Initial Regional Plan or a Change Case, that delineate the more efficient or cost-effective regional transmission plan, as measured economically by changes in capital related costs, losses and reserve margin, and adjusted by their effects on neighboring regions, will be selected into NTTG's Regional Transmission Plan. A more detailed discussion of NTTG's study process can be found in NTTG's Biennial Study Plan posted on NTTG's website.

NTTG will coordinate its ITP planning assumptions and data with the other Relevant Planning Region. It should also be noted that the Cross-Tie Project submitted into NTTG's regional planning process identified, as a project objective, the ability to deliver renewable generation from NTTG's planning region to support the California ISO's future RPS requirements. Coordination to ensure appropriate resources in California are dispatched down or turned off to accommodate renewable resource from the NTTG planning region has not yet been determined.

WestConnect

WestConnect's 2018-19 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2018.[3] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2018. If regional needs are identified during Q4 of 2018, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2018-19 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternatives provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan and will not result in Order 1000 regional cost allocation. The WestConnect Planning Management Committee has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

Cross-Tie Project representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2018-19 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2019. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2018-19 Study Plan. These studies are also outlined in Figure 2.

Figure 2: WestConnect 2018-19 Transmission Assessment Summary

[3] https://doc.westconnect.com/Documents.aspx?NID=18068&dl=1

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

10-Year Base Cases (2028)	10-Year Scenarios (2028)
Heavy Summer (reliability) Light Spring (reliability) Base Case (economic)	Load Stress Study (reliability) CAISO Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

Data and Study Methodologies

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized the types of studies that will be conducted that are relevant to the Cross-Tie Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 3: Relevant Planning Region Study Summary Matrix

Planning Study	NTTG	WestConnect
Economic/Production Cost Model	Using the NTTG PCM Base Case, based on the WECC 2028 ADS Case, GridView will be used to conduct PCM analysis to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint	Regional Economic Assessment will be performed on WestConnect 2028 Base Case PCM (based on WECC 2028 Anchor Data Set[5]
Reliability/Power Flow Assessment	The selected stressed hours will be transferred from GridView to the PowerWorld power flow model to conduct reliability analysis	Regional Reliability Assessment will be performed on WestConnect 2028 Heavy Summer and Light Spring cases[6]

[5] WestConnect TP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2018-19 Base Case transmission needs assessments.
[6] Id

Note that the Cross-Tie Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2028 Anchor Data Set (ADS) as the starting point data set for regional economic planning studies conducted in 2018 and 2019 (as applicable). Each Planning Region intends to update the 2028 ADS with their most recent and relevant regional planning assumptions to reflects its starting point transmission topology and generation data. The Planning Regions will strive to coordinate major updates made to the 2028 ADS as part of their regional model development efforts in late Q3, 2018.[7]

As an example, the California ISO will update the 2028 ADS to reflect their most recent Transmission Plan.[8]
NTTG will ensure that its prior Regional Transmission Plan[9] is reflected. WestConnect will represent their current Base Transmission Plan,[10] and ColumbiaGrid will provide major updates to the 2028 ADS based on the information from the latest Biennial Plan[11] to other Planning Regions subject to each region's applicable confidentiality requirements.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region, but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality requirements. The identification of the starting WECC power flow cases ("seed cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the

[7] This schedule is dependent on the 2028 Anchor Data Set being provided by WECC no later than the end of Q2, 2018, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.

[8] California ISO 2017-2018 Transmission Plan

[9] NTTG 2016-2017 Regional Transmission Plan

[10] WestConnect 2018-2019 Base Transmission Plan

[11] ColumbiaGrid Update to the 2017 Biennial Transmission Plan

inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan.

Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the Cross-Tie Project is a more efficient or cost- effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Relevant Planning Region's cost share of the Cross-Tie Project will be calculated based on its share of the calculated benefits provided to the Region by the Cross-Tie Project (as quantified per that Region's planning process). The project cost of the Cross-Tie Project, as provided in their ITP Submittal form, is provided below.

Figure 4: Cross-Tie Project Sponsor Cost Information[12]

Project Configuration	Cost ($)
Full project cost estimate	$667.0 million (2015 $$)

Following are key assumptions upon which this cost estimate is based that are worth noting to facilitate a comparison of costs to other projects being evaluated:

- Includes initial estimate of $91.0 million for upgrades on the existing system at Robinson Summit substation and on the Robinson Summit to Harry Allen 500-kV transmission line, based on preliminary studies provided as a part of the project submission. The extent of these upgrades will need to be confirmed through additional technical studies and would most likely apply to other projects looking to connect at Robinson Summit.
- Includes AFUDC and overheads of ~$100.0 million (estimated at 17.5% of total costs) per the TEPPC cost calculator.

The following Table 5 provides a detailed breakdown of the total project cost submitted by TransCanyon for use by Planning Regions for their analysis and cost allocation.

Figure 5: Cross-Tie Project Sponsor Cost Breakdown

Project Component Cost	Per Mile	Total
Clover - Robinson Summit line	$ 2,319,250.45	$ 461,530,838.79
ROW Cost	$ 19,964.14	$ 3,972,864.00
Clover Substation	N/A	$ 10,959,685.80
Robinson Summit	N/A	$ 28,930,423.20
Substation Adjustments	N/A	$ 62,000,000.00

[12] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

AFUDC/Overhead @17.5%	$ 501,215.01	$ 99,741,787.84
All Costs	$ 2,840,429.60	$ 667,135,599.63

After each Relevant Planning Region identifies their transmission needs and (as applicable) the benefits of the ITP, project costs for each Region to use in the determination of the more efficient or cost-effective alternatives for the region will be determined as follows:

Assumptions
Total Benefits ($) = NTTG Benefits ($) + WestConnect Benefits ($)
Project Cost ($) = Total capital cost of project, as agreed upon by Regions

Cost Calculations (for Planning Purposes)
NTTG Cost for Planning Purposes = [NTTG Benefits/Total Benefits] * Project Cost
WestConnect Cost for Planning Purposes = [WestConnect Benefits/Total Benefits] * Project Cost

Note that this information on cost assumptions applies to costs that will be used for planning evaluation purposes. These costs may be different than what is assumed for any relevant cost allocation procedures.

Cost Allocation

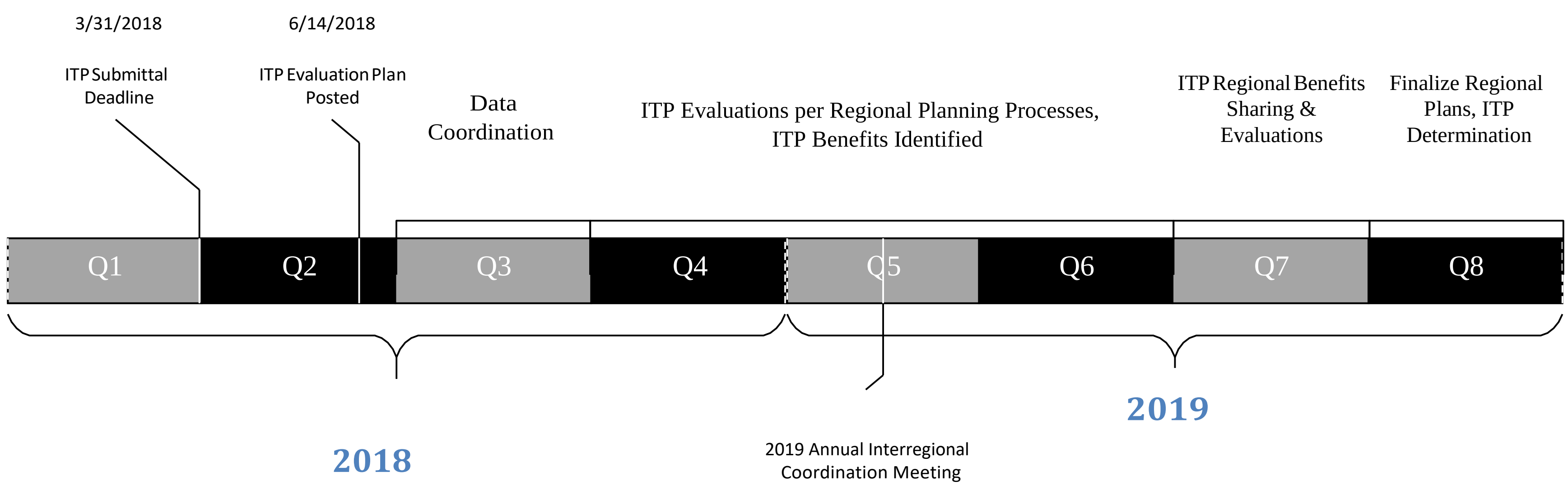
Interregional cost allocation may apply for the Cross-Tie Project for the 2018-2019 cycle.

TransCanyon requested cost allocation from NTTG and from WestConnect and met the necessary requirements within each respective Planning Region’s regional process to be considered eligible to request cost allocation. If both NTTG and WestConnect subsequently select the Cross-Tie project in their respective regional transmission plans for purposes of Interregional Cost Allocation, NTTG and WestConnect will individually apply their regional cost allocation methodology to the projected costs of the Cross-Tie project assigned to each region as described in the previous section and in accordance with each region’s regional cost allocation methodology. If only one of the two Relevant Planning Regions for the Cross-Tie Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the Cross-Tie project is reduced to one, the project will no longer be eligible for interregional cost allocation.

Schedule and Evaluation Milestones

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2018 and (as applicable) 2019. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 6: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

Contact Information

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Planning Region:	Northern Tier Transmission Group
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Planning Region:	WestConnect
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ITP Evaluation Process Plan

TransWest Express DC Project

June 14, 2018

The goal of the coordinated Interregional Transmission Project (ITP) evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP. The joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP. The purpose of this document is to provide a common framework, coordinated by the Western Planning Regions, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan will be developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Region to which it was submitted.

ITP Submittal Summary

Project Submitted To:	California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect
Relevant Planning Regions[1]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

1 ITP Summary

The TransWest Express Transmission DC Project (TWE DC Project) is a proposed 730-mile, phased 1,500/3,000 MW, ±600 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada.

The TWE DC Project northern terminal will be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW Chokecherry and Sierra Madre Wind Energy Project1. The TWE Project design provides for

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

The TWE DC Project southern terminal will be interconnected to the 500 kV Eldorado substation in the CAISO planning region. It also will be interconnected to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

The TWE Project has an in-service date of 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017, following eight years of environmental analysis under the National Environmental Policy Act, four federal agencies -- the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) -- issued records of decision finalizing and approving the route for the TWE Project on federal lands.2 WAPA acted as a joint lead agency with the BLM on the Environmental Impact Statement (EIS) and is considering further participation in the TWE Project through its Transmission Infrastructure Program. The BLM and WAPA published the Final Environmental Impact Statement (FEIS) for the TWE Project on May 1, 2015.

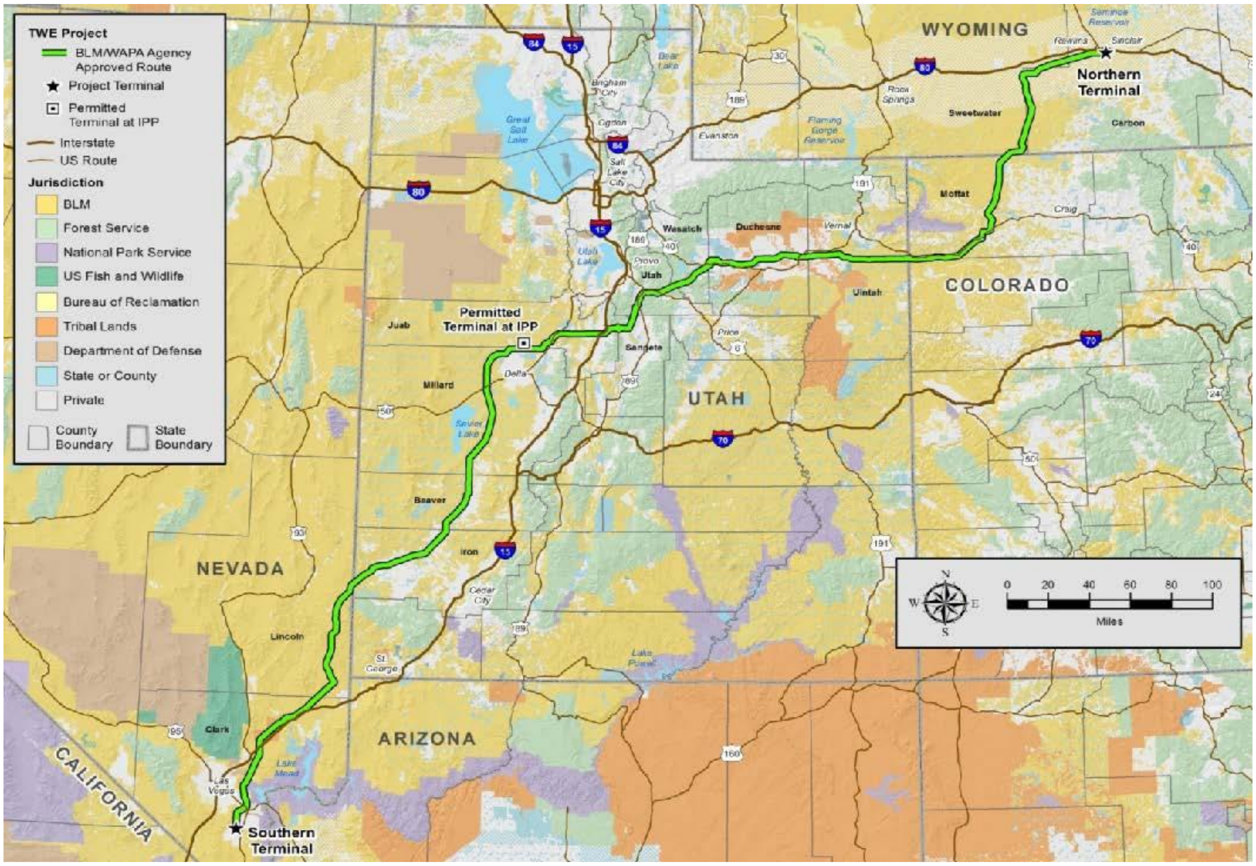
A project map of the proposed project is shown in Figure 6.

2 Evaluation by Relevant Planning Regions

The California ISO has been identified as the Planning Region that will lead the coordination efforts with the other Relevant Planning Regions identified for the ITP. In this capacity, the California ISO will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

Figure 6: TWE DC Transmission Route
(Source: TWE DC Project Summary)



2.1 California ISO

The project sponsor states that the TWE DC Project is proposed as a two phase project with an initial rating of 1,500 MW. Phase 1 would consist of building the fully rated 3,000 MW transmission line using triple conductor (Athabaska Aluminum Steel Core Reinforced conductor). Then, each terminal would have a 1,500 MW bi-pole configured line current commutated HVDC converter with AC substations, including filters and dynamic compensation devices, AC interconnections, a communication system and ground electrode facilities. In November 2017, the Western Electricity Coordinating Council granted the TWE DC Project Phase 3, Accepted Rating status with a capacity up to 1,500 MW.

Phase 2 would consist of adding 1,500 MW of parallel HVDC converter equipment at each of the terminals. Figure 2 is a map of the proposed TWE Project superimposed on the existing transmission facilities and other planned projects. Figure 3 is the one-line diagram for the proposed TWE Project

The project sponsor states that the TWE DC Project will provide direct bidirectional transmission capacity from Wyoming wind resources and the diverse Rocky Mountain load centers to replace and support a portion of the Public Policy and Economic Regional Needs of the three planning regions. The project sponsor further states that several “independent” studies have analyzed the project and concluded that the TWE Project will provide California rate-payers significant savings while addressing the “lack of certainty” around accessing geographically diverse renewable resources. The TWE DC Project would also support meeting Regional Needs within the California ISO, NTTG, and WestConnect by providing “Public Policy” and “Economic” benefits to each of the three Relevant Planning Regions and as defined by Arizona, California, and Nevada.

The TWE DC Project was submitted into the 2016-2017 interregional coordination cycle where the California ISO considered the proposed project in the context of California’s 50% RPS goal where accessing out-of-state renewable resources for California was considered in the proposed project’s assessment at a “high” or “cursory” level. The effort to perform an “informational” assessment of California procurement of out-of-state resources was concluded and documented in the 2017-2018 Transmission Plan[2].

California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and “informational” policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO’s planning process be obtained from within California. As such, the 2018-2019 planning process will consider the TWE DC Project in the context of production cost simulation benefits from importing and exporting surplus resources between California and the Wyoming area. However, if the ISO does not observe any significant transmission congestion in its production cost simulation studies without the TWE DC Project modeled that could be reasonably expected be mitigated by the TWE DC project, then it may be unnecessary to proceed any further with the analysis. Given that the renewable portfolios in the 2018-2019 transmission planning cycle do not include any wind generation in Wyoming, it is possible that no significant congestion will be identified that the TWE DC project would be expected to mitigate. If the production cost analysis produces adequate economic benefits to proceed further with the analysis, then powerflow and stability analysis will be performed as well.

The California ISO will develop the detailed modeling information for the GridView and GE PSLF computer programs and exchange that information with WestConnect commensurate with existing data confidentiality requirements.

2.2 NTTG

The NTTG Regional Transmission Plan evaluates whether transmission needs within the NTTG Footprint may be satisfied on a regional and interregional basis more efficiently or cost effectively than through local planning processes. While the NTTG Regional Transmission Plan is not a construction plan, it provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

[2] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

The first step in developing NTTG's 2018-2019 Regional Transmission Plan is to identify the Initial Regional Plan that includes NTTG's Funding Transmission Providers' local transmission plans and the uncommitted projects in NTTG 2016-2017 Regional Transmission Plan. NTTG then uses Change Cases to evaluate regional and interregional transmission projects that may produce a more efficient or cost effective regional transmission plan for NTTG's footprint. A Change Case is a scenario where one or more of the uncommitted transmission project(s) in the Initial Regional Plan will be added to, defer, or replace one or more of the other non-committed project(s) in the Initial Regional Plan.

The Initial Regional Plan and Change Cases will be evaluated using power flow and dynamic analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. If the Change Case fails to meet these minimum reliability requirements, it will either be set aside as unacceptable or modified by the addition of another uncommitted project to ensure transmission reliability. The number of Change Cases will be determined through the technical planning process to carefully examine the reliability of and need for the non-committed regional and interregional projects to meet the region's transmission needs. The set of uncommitted projects, either from the Initial Regional Plan or a Change Case, that delineate the more efficient or cost-effective regional transmission plan, as measured economically by changes in capital related costs, losses and reserve margin, and adjusted by their effects on neighboring regions, will be selected into NTTG's Regional Transmission Plan. A more detailed discussion of NTTG's study process can be found in NTTG's Biennial Study Plan posted on NTTG's website.

2.3 WestConnect

WestConnect's 2018-19 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2018.[3] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2018. If regional needs are identified during Q4 of 2018, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2018-19 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternative(s) provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified

[3] https://doc.westconnect.com/Documents.aspx?NID=18068&dl=1

regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan, and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

TWE DC Project representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2018-19 Planning Cycle. These studies, as outlined in Table 1, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2019. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2018-19 Study Plan. These studies are also outlined in Table 1.

Table 1: WestConnect 2018-19 Transmission Assessment Summary

10-Year Base Cases (2028)	**10-Year Scenarios (2028)**
Heavy Summer (reliability) Light Spring (reliability) Base Case (economic)	Load Stress Study (reliability) CAISO Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

3 Data and Study Methodologies

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. The Relevant Planning Regions have summarized, in Table 2, the types of studies that will be conducted that are relevant to the TWE DC Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Table 2: Relevant Planning Region Study Summary Matrix

Planning Study	**California ISO**	**NTTG**	**WestConnect**
Economic/Production Cost Model	Using the California ISO PCM Base Case, based on the WECC 2028 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect.	Using the NTTG PCM Base Case, based on the WECC 2028 ADS Case, GridView will be used to conduct PCM analysis to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint	Regional Economic Assessment will be performed on WestConnect 2028 Base Case PCM (based on WECC 2028 Anchor Data Set[5])
Reliability/Power Flow Assessment	Depending on the results of the production cost modeling, the GE PSLF may be used to perform steady state and as needed, transient analysis. The WECC 2028 ADS and 2028 LSP1 will be modified as needed	The selected stressed hours will be transferred from GridView to the PowerWorld power flow model to conduct reliability analysis	Regional Reliability Assessment will be performed on WestConnect 2028 Heavy Summer and Light Spring cases[6]

[5] WestConnect ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2018-19 Base Case transmission needs assessments.
[6] Id

	to accurately model the California network and resources that reflects the ISO's finalized 2017-2018 transmission plan. The TWE DC Project will be added to that model. All model information will be shared with WestConnect.		

Note that the TWE DC Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

4 Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

4.1 Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2028 Anchor Data Set (ADS) as the starting point data set for regional economic planning studies conducted in 2018 and 2019 (as applicable). Each Planning Region intends to update the 2028 ADS with their most recent and relevant regional planning assumptions to reflect its starting point transmission topology and generation data. The Planning Regions will strive to coordinate major updates made to the 2028 ADS as part of their regional model development efforts in late Q3, 2018.[7]

As an example, the California ISO will update the 2028 ADS to reflect their recently completed 2017-2018 Transmission Plan[8]. NTTG will ensure that its prior Regional Transmission Plan[9] is reflected. WestConnect will represent their current Base Transmission Plan[10] and ColumbiaGrid will provide major updates to the 2028 ADS based on the information from the latest Biennial

[7] This schedule is dependent on the 2028 Anchor Data Set being provided by WECC no later than the end of Q2, 2018, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.

[8] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

[9] NTTG 2016-2017 Regional Transmission Plan

[10] WestConnect 2018-2019 Base Transmission Plan

Plan[11] to other Planning Regions subject to each region's applicable confidentiality requirements.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

4.2 Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region, but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality requirements. The identification of the starting WECC power flow cases ("seed cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan.

4.3 Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the TWE DC Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Region's cost share of the TWE DC Project will be calculated based on its share of the calculated benefits provided to the Region by the TWE DC Project (as quantified per that Region's planning process). The project cost of the TWE DC Project, as provided in their ITP Submittal form, is provided in Table 3.

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Table 3: Project Sponsor Cost Information[12]

Project Configuration	**Cost ($)** **(2018$)**
Initial phase (1500 MW)	$2.11 billion
Full project (3000 MW)	$2.98 billion

[11] ColumbiaGrid Update to the 2017 Biennial Transmission Plan

[12] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

4.4 Cost Allocation

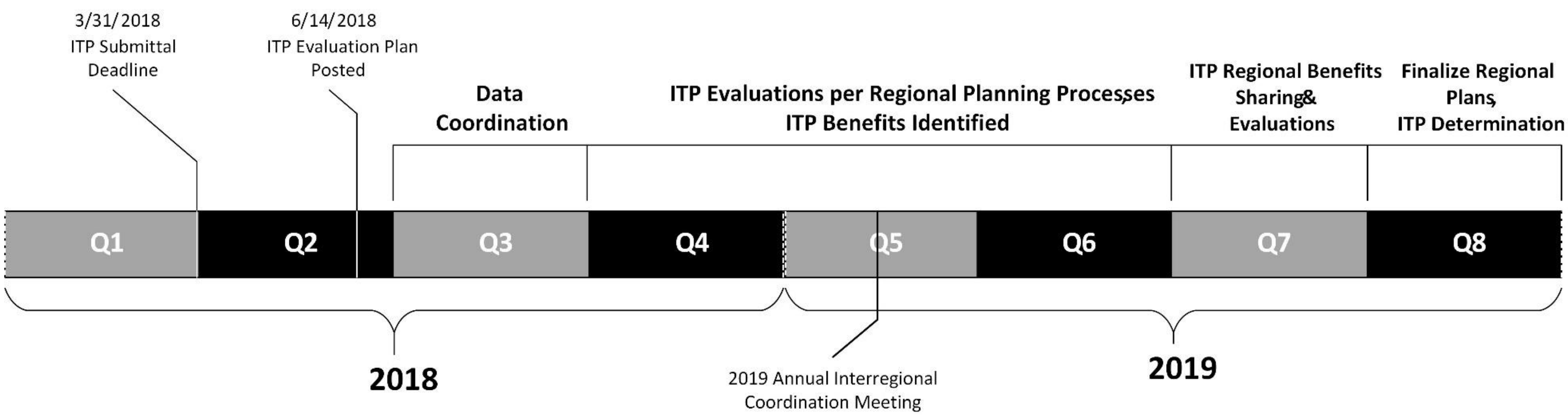
Interregional cost allocation may apply for the TWE DC Project for the 2018-2019 cycle.

TransWest Express LLC requested cost allocation from California ISO and from WestConnect and met the necessary requirements within each respective Planning Region's regional process to be considered eligible to request cost allocation. If both California ISO and WestConnect subsequently select the TWE DC Project in their respective regional transmission plans for purposes of Interregional Cost Allocation, California ISO and WestConnect will individually apply their regional cost allocation methodology to the projected costs of the TWE DC Project assigned to each region as described in the previous section and in accordance with each region's regional cost allocation methodology. If only one of the two Relevant Planning Regions for the TWE DC Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the TWE DC Project is reduced to one, the project will no longer be eligible for interregional cost allocation.

5 Schedule and Evaluation Milestones

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2018 and (as applicable) 2019. The ITP Evaluation Timeline, shown in Figure 7, was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 7: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

6 Contact Information

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Planning Region: California ISO
Name: Gary DeShazo
Telephone: 916-608-5880
Email: gdeshazo@caiso.com

Planning Region: NTTG
Name: Sharon Helms
Telephone: (503) 644-6262
Email: sharon.helms@comprehensivepower.org

Planning Region: WestConnect
Name: Charlie Reinhold
Telephone: 208-253-6916
Email: reinhold@ctweb.net

ITP Evaluation Process Plan

TransWest Express AC/DC Project

June 14, 2018

The goal of the coordinated Interregional Transmission Project (ITP) evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP. The joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP. The purpose of this document is to provide a common framework, coordinated by the Western Planning Regions, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan will be developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Region to which it was submitted.

ITP Submittal Summary

Project Submitted To:	California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect
Relevant Planning Regions[1]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

1 ITP Summary

The TransWest Express Transmission AC & DC Project (TWE DC Project) consists of a proposed 406-mile, phased 1,500/3,000 MW, ±500 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and central Utah, and a 324- mile, 1,500 MW 500 kV alternating current transmission system with terminals in central Utah and southeastern Nevada.

The TWE AC & DC Project northern terminal will be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

Chokecherry and Sierra Madre Wind Energy Project.[2] The TWE Project design provides for connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

The TWE AC & DC Project's Utah, or southern DC, terminal will be interconnected to the 345 kV Intermountain Power Plant substation in the WestConnect planning region. The 500 kV AC line will connect the Utah terminal to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

The TWE Project has an in-service date of 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017, following eight years of environmental analysis under the National Environmental Policy Act, four federal agencies -- the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) -- issued records of decision finalizing and approving the route for the TWE Project on federal lands.[3] WAPA acted as a joint lead agency with the BLM on the Environmental Impact Statement (EIS) and is considering further participation in the TWE Project through its Transmission Infrastructure Program. The BLM and WAPA published the Final Environmental Impact Statement (FEIS) for the TWE Project on May 1, 2015. The route for the TWE Project is shown in Figure 1 below.

A project map of the proposed project is shown in Figure 6.

2 Evaluation by Relevant Planning Regions

The California ISO has been identified as the Planning Region that will lead the coordination efforts with the other Relevant Planning Regions identified for the ITP. In this capacity, the California ISO will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

A map of the proposed project is shown in Figure 6.

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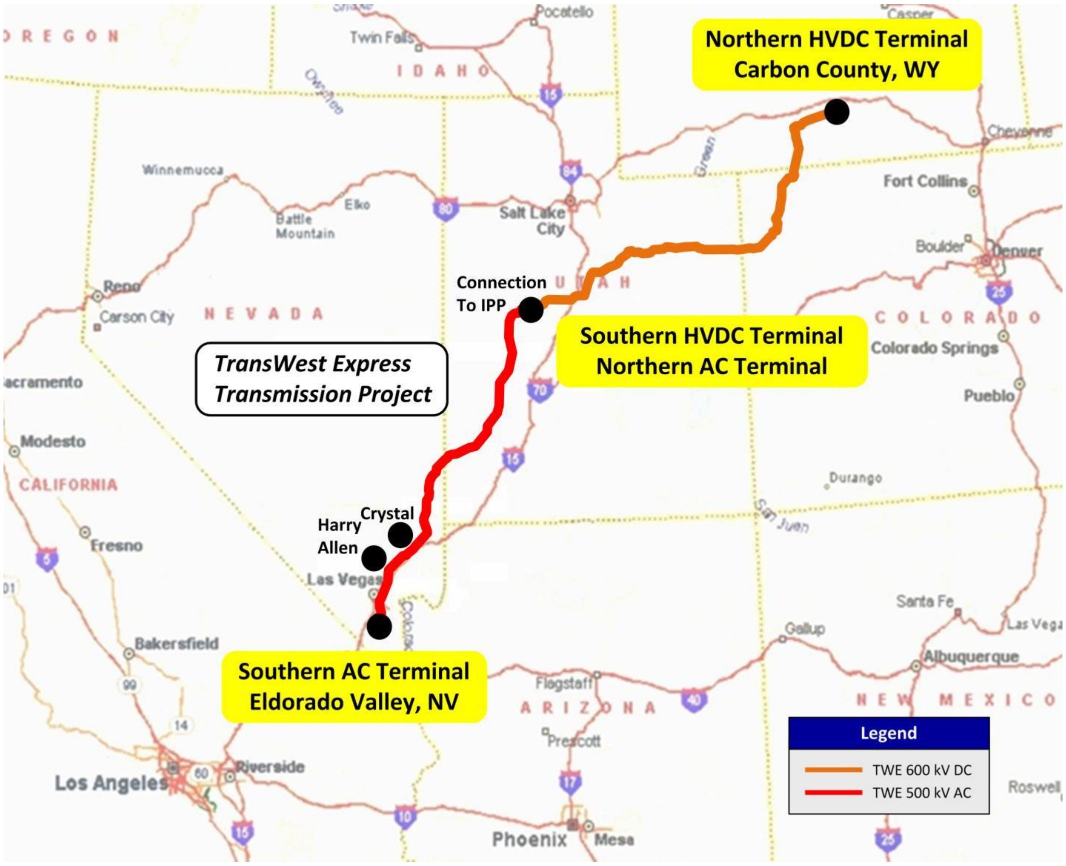
[2] The Chokecherry and Sierra Madre Wind Energy Project is being developed in two 1,500 MW phases by Power Company of Wyoming LLC, an affiliate of TransWest. More information about PCW and the CCSM Project is available at www.powercompanyofwyoming.com.

[3] See BLM ROD TransWest December 2016, WAPA ROD TWE Project , January 2017, USFS ROD TWE Project , May 2017, BOR ROD TWE Project , June 2017

Figure 8: TWE AC/DC Transmission Route
(Source: TWE AC/DC Project Summary)



2.1 California ISO

The project sponsor states that the TWE AC/DC Project is proposed as a two phase project with an initial rating of 1,500 MW. Phase 1 would consist of building the fully rated 3,000 MW transmission line using triple conductor (Athabaska Aluminum Steel Core Reinforced conductor). Then, each terminal would have a 1,500 MW bi-pole configured line current commutated HVDC converter with AC substations, including filters and dynamic compensation devices, AC interconnections, a communication system and ground electrode facilities. Phase 2 would consist of adding 1,500 MW of parallel HVDC converter equipment at each of the terminals.

The 500 kV AC portion will include a series compensation station in Utah. The TWE Project route runs immediately adjacent the 500 kV AC Crystal and Harry Allen north of Las Vegas. Alternative termination points for the 500 kV line could be either of these substations, thus eliminating the need for approximately 60 miles of transmission line.

The project sponsor states that the TWE AC/DC Project will provide needed transmission capacity between the Desert Southwest and California regions, represented by CAISO and

WestConnect, and the Rocky Mountain region, represented by NTTG and WestConnect. This additional transmission capacity will facilitate access between diverse renewable resources and diverse utility load profiles. The TWE Project will facilitate access by the Desert Southwest/California market to Wyoming's vast renewable wind resources. This direct interconnection will result in lowering the cost of RPS compliance for the Desert Southwest while simultaneously providing the vast solar resources in the Desert Southwest with access to Rocky Mountain regional markets, such as the Denver and Salt Lake City metro areas.

The TWE Project is designed to expand the existing transmission network with connections to major existing and planned transmission in Wyoming and Nevada. Figure 6 depicts the transmission capacity that the 3,000 MW TWE Project would provide between planning regions.

This will be the first time that the California ISO will consider the TWE AC/DC project as an ITP in its planning cycle. In the 2016-2017 interregional coordination cycle the California ISO considered several proposed projects in the context of California's 50% RPS goal where accessing out-of-state renewable resources for California was considered in the proposed project's assessment at a "high" or "cursory" level. The effort to perform an "informational" assessment of California procurement of out-of-state resources was concluded and documented in the 2017-2018 Transmission Plan[4].

California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO's planning process be obtained from within California. As such, the 2018-2019 planning process will consider the TWE AC/DC Project in the context of production cost simulation benefits from importing and exporting surplus resources between California and the Wyoming area. However, if the ISO does not observe any significant transmission congestion in its production cost simulation studies without the TWE DC Project modeled that could be reasonably expected be mitigated by the TWE DC project, then it may be unnecessary to proceed any further with the analysis. Given that the renewable portfolios in the 2018-2019 transmission planning cycle do not include any wind generation in Wyoming, it is possible that no significant congestion will be identified that the TWE DC project would be expected to mitigate. If the production cost analysis produces adequate economic benefits to proceed further with the analysis, then powerflow and stability analysis will be performed as well.

The California ISO will develop the detailed modeling information for the GridView and GE PSLF computer programs and exchange that information with WestConnect commensurate with existing data confidentiality requirements.

[4] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

2.2 NTTG

The NTTG Regional Transmission Plan evaluates whether transmission needs within the NTTG Footprint may be satisfied on a regional and interregional basis more efficiently or cost effectively than through local planning processes. While the NTTG Regional Transmission Plan is not a construction plan, it provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NTTG's 2018-2019 Regional Transmission Plan is to identify the Initial Regional Plan that includes NTTG's Funding Transmission Providers' local transmission plans and the uncommitted projects in NTTG 2016-2017 Regional Transmission Plan. NTTG then uses Change Cases to evaluate regional and interregional transmission projects that may produce a more efficient or cost effective regional transmission plan for NTTG's footprint. A Change Case is a scenario where one or more of the uncommitted transmission project(s) in the Initial Regional Plan will be added to, defer, or replace one or more of the other non-committed project(s) in the Initial Regional Plan.

The Initial Regional Plan and Change Cases will be evaluated using power flow and dynamic analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. If the Change Case fails to meet these minimum reliability requirements, it will either be set aside as unacceptable or modified by the addition of another uncommitted project to ensure transmission reliability. The number of Change Cases will be determined through the technical planning process to carefully examine the reliability of and need for the non-committed regional and interregional projects to meet the region's transmission needs. The set of uncommitted projects, either from the Initial Regional Plan or a Change Case, that delineate the more efficient or cost-effective regional transmission plan, as measured economically by changes in capital related costs, losses and reserve margin, and adjusted by their effects on neighboring regions, will be selected into NTTG's Regional Transmission Plan. A more detailed discussion of NTTG's study process can be found in NTTG's Biennial Study Plan posted on NTTG's website.

2.3 WestConnect

WestConnect's 2018-19 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2018.5 The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2018. If regional needs are identified during Q4 of 2018, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified

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regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2018-19 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternative(s) provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[6]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan, and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

TWE AC/DC Project representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2018-19 Planning Cycle. These studies, as outlined in Table 4, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2019. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2018-19 Study Plan.

Table 4: Relevant Planning Region Study Summary Matrix

10-Year Base Cases (2028)	10-Year Scenarios (2028)
Heavy Summer (reliability) Light Spring (reliability) Base Case (economic)	Load Stress Study (reliability) CAISO Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

[6] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

3 Data and Study Methodologies

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. The Relevant Planning Regions have summarized, in Table 5, the types of studies that will be conducted that are relevant to the TWE AC/DC Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Table 5: Relevant Planning Region Study Summary Matrix

Planning Study	California ISO	NTTG	WestConnect
Economic/Production Cost Model	Using the California ISO PCM Base Case, based on the WECC 2028 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect.	Using the NTTG PCM Base Case, based on the WECC 2028 ADS Case, GridView will be used to conduct PCM analysis to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint	Regional Economic Assessment will be performed on WestConnect 2028 Base Case PCM (based on WECC 2028 Anchor Data Set[7]
Reliability/Power Flow Assessment	Depending on the results of the production cost modeling, the GE PSLF may be used to perform steady state and as needed, transient analysis. The WECC 2028 ADS and	The selected stressed hours will be transferred from GridView to the PowerWorld power flow model to conduct reliability analysis	Regional Reliability Assessment will be performed on WestConnect 2028 Heavy Summer and Light Spring cases[8]

[7] WestConnect ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2018-19 Base Case transmission needs assessments.

[8] Id

	2028 LSP1 will be modified as needed to accurately model the California network and resources that reflects the ISO's finalized 2017-2018 transmission plan. The TWE AC/DC Project will be added to that model. All model information will be shared with WestConnect.		

Note that the TWE AC/DC Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

4 Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

4.1 Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2028 Anchor Data Set (ADS) as the starting point data set for regional economic planning studies conducted in 2018 and 2019 (as applicable). Each Planning Region intends to update the 2028 ADS with their most recent and relevant regional planning assumptions to reflect its starting point transmission topology and generation data. The Planning Regions will strive to coordinate major updates made to the 2028 ADS as part of their regional model development efforts in late Q3, 2018.[9]

As an example, the California ISO will update the 2028 ADS to reflect their most recent Transmission Plan. NTTG will ensure that its prior Regional Transmission Plan[10] is reflected. WestConnect will represent their current Base Transmission Plan[11] and ColumbiaGrid will

[9] This schedule is dependent on the 2028 Anchor Data Set being provided by WECC no later than the end of Q2, 2018, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.

[10] NTTG 2016-2017 Regional Transmission Plan

[11] WestConnect 2018-2019 Base Transmission Plan

provide major updates to the 2028 ADS based on the information from the latest Biennial Plan[12] to other Planning Regions subject to each region's applicable confidentiality requirements.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

4.2 Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region, but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality requirements. The identification of the starting WECC power flow cases ("seed cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan.

4.3 Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the TWE AC/DC Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Region's cost share of the TWE AC/DC Project will be calculated based on its share of the calculated benefits provided to the Region by the TWE AC/DC Project (as quantified per that Region's planning process). The project cost of the TWE AC/DC Project, as provided in their ITP Submittal form, is provided in Table 6.

Table 6: Project Sponsor Cost Information[13]

Project Configuration	Cost ($) (2018$)
DC Facility (1500 MW)	$1.62 billion
DC Facility (3000 MW)	$2.49 billion
AC Facility	$600 million

[12] ColumbiaGrid Update to the 2017 Biennial Transmission Plan

[13] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process.

4.4 Cost Allocation

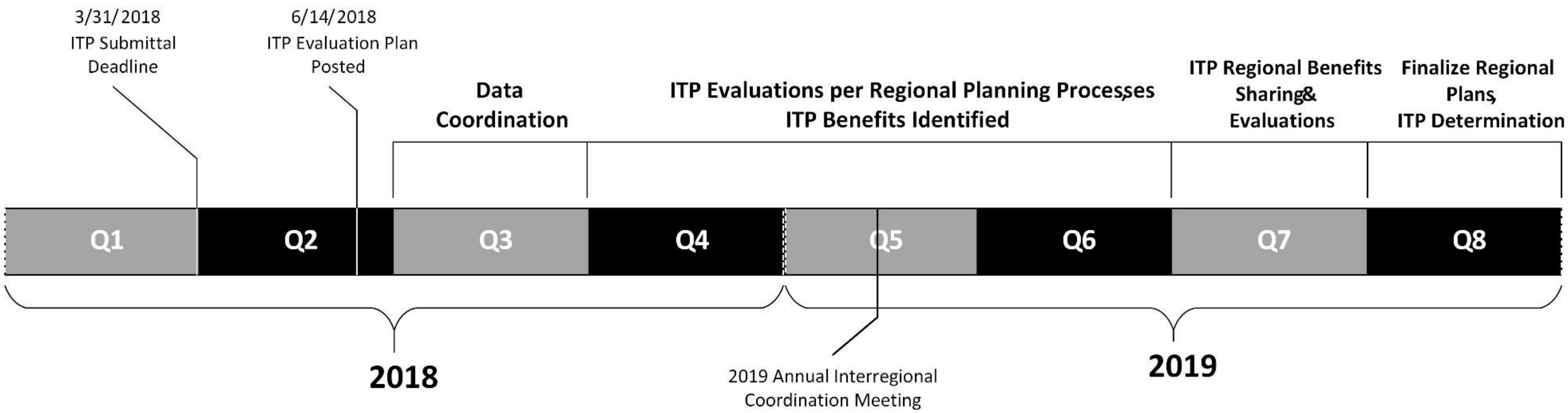
Interregional cost allocation may apply for the TWE AC/DC Project for the 2018-2019 cycle.

TransWest Express LLC requested cost allocation from California ISO and from WestConnect, and met the necessary requirements within each respective Planning Region's regional process to be considered eligible to request cost allocation. If both California ISO and WestConnect subsequently select the TWE AC/DC Project in their respective regional transmission plans for purposes of Interregional Cost Allocation, California ISO and WestConnect will individually apply their regional cost allocation methodology to the projected costs of the TWE AC/DC Project assigned to each region as described in the previous section and in accordance with each region's regional cost allocation methodology. If only one of the two Relevant Planning Regions for the TWE AC/DC Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the TWE AC/DC Project is reduced to one, the project will no longer be eligible for interregional cost allocation.

5 Schedule and Evaluation Milestones

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2018 and (as applicable) 2019. The ITP Evaluation Timeline, shown in Figure 9, was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 9: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

6 Contact Information

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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