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

Northwestern Energy
Crooked Falls Switchyard

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.

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

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).

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.

- **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.

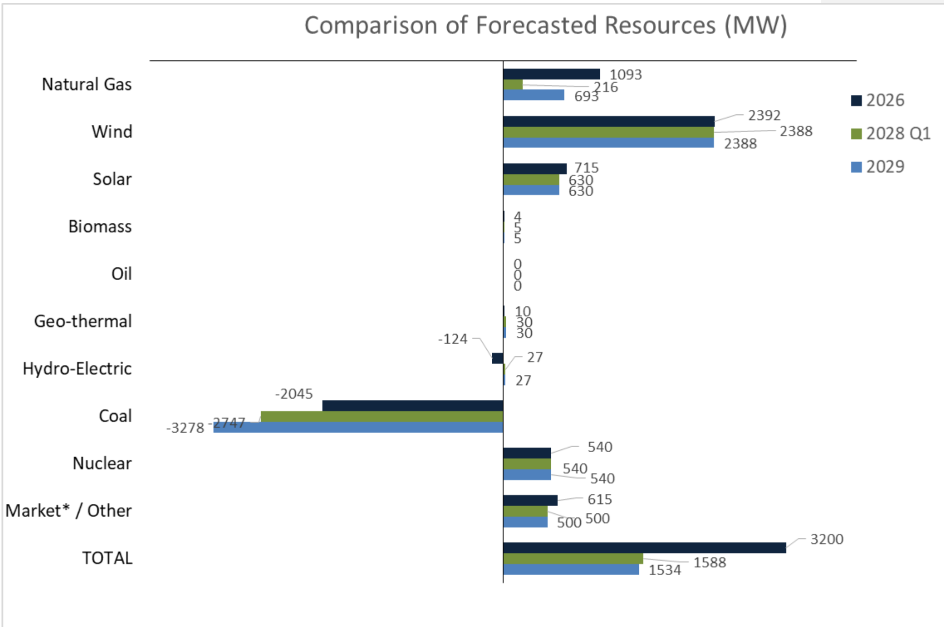

Figure 1: Comparison of Forecasted Resources

As shown in this figure, the total resource forecast of 1588 MW submitted this cycle is significantly reduced (-1612 MW or -50.3%) 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	516

Table 2: Location of 2028 Forecasted Resources

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

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[5]" 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[6]**
Naughton 3	12/2018
Valmy 1	12/2019
Boardman	12/2020
Cholla 4[4]	12/2020
Colstrip 1 & 2	7/2022
Valmy 2	12/2025
Craig 1[4]	12/2025
Dave Johnson 1, 2, 3, 4	12/2027
Bridger 1	12/2028

Table 3 – Planned Coal Retirements prior to next Planning Cycle (2030-2031)

<u>Regional Transmission Projects</u>: 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 sponsors, identified the regional transmission projects shown in the table below as the list of regional projects submitted in Quarter 1 data submittal that will be analyzed during this biennial Regional Planning Cycle.

[5] Idaho Power OATT, section 18.4.1
[6] Units are assumed to retire at the end of the stated month.

JANUARY 2018 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2028

Sponsor	From	To	Voltage	Circuit	Type	Regionally Significant[7]	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 (2024)
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie (2024)
	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)
			115 kV	1	LTP	No	Yes	Various Load Service Additions (2019-2024)

Table 4 – New Transmission Projects

[7] 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

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. <u>Transmission Service Obligations</u>: Listed below in Table 5 are the transmission obligations that were submitted in Quarter 1.

Submitted by	MW[8]	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).

Commented [RDS1]: Table 6 data has not been updated, TWG is compiling Firm ATC data for 2018

Path Name	Existing Path Rating (MW)	Available Transfer Capability(*2018*)
8 – Montana to Northwest	E-W: 2200 W-E: 1350	E-W: 698* W-E: 652**
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: xx** W-E: 1350
18 – Idaho to Montana	N-S: 383 S-N: 256	
19 – Bridger West	E-W: 2400 MW W-E: 1250 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: 880	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	
83 – MATL	N-S: 300 S-N: 300	N-S: 0 S-N:0

[8] Summer/Winter service requirements

Path 8 Notes:
- * This includes 184 MW owned by BPA which ties into the same Garrison substation as some of the other capacity, but BPA does not consider this part of path 8. They consider it part of paths 9 & 10.
- ** 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[9]	Great Basin Transmission LLC	CAISO[10], NTTG, WestConnect	Midpoint, ID	Robinson Summit, NV	Permitted	2021
TransWest Express Transmission Project[11]	TransWest Express, LLC	CAISO, NTTG, WestConnect	Rawlins, WY	Boulder City, NV	Conceptual	2020

Commented [SH2]: Final determination of Relevant Planning Regions will be aligned with the adoption of ITP Evaluation Process Plans on or prior to June 14, 2018.

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[12] 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.

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[9] 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.

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

[11] 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.

[12] 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[13]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 Alternative identified by the TWG will be included in the Initial Regional Plan base case. The

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

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 uncommitted projects in the Initial Regional Plan provided the substitution of the uncommitted 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[14] through the Local Transmission Plans of the NTTG Transmission Providers.

[14] See Attachment K, Local Planning process

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

[15] 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.

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.

Commented [RDS3]: Figure 2 will be updated.

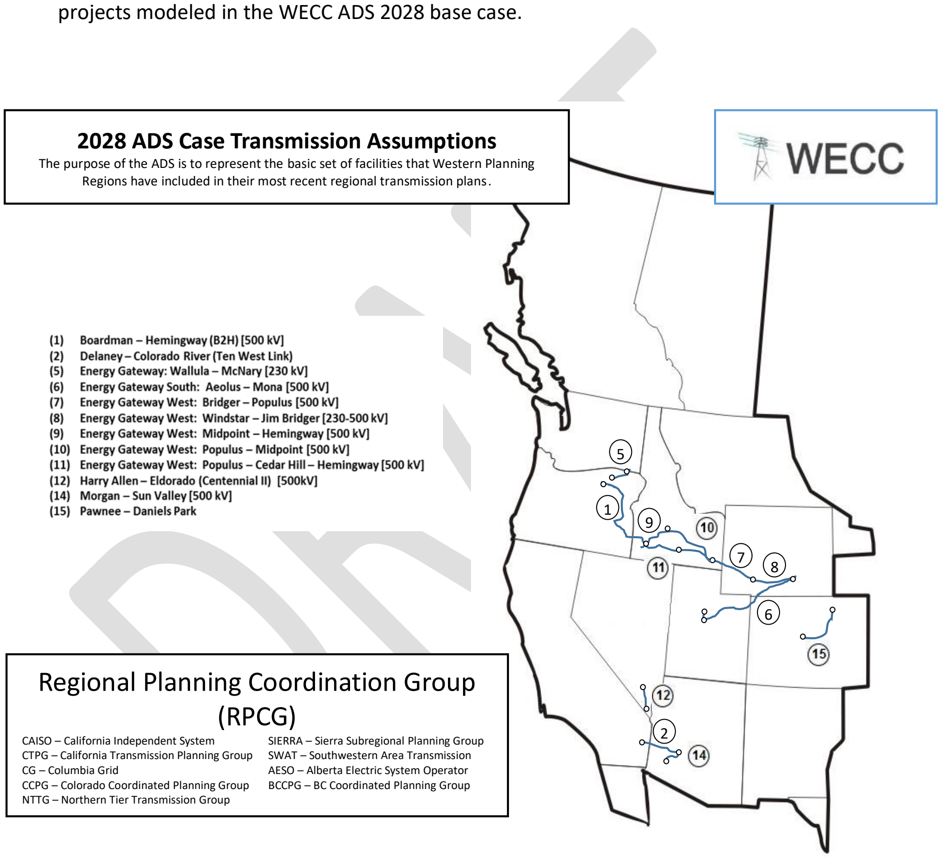

Figure 2 – ADS Significant Regional Transmission

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[16]; 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 list of 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.

[16] Using a simultaneous analysis described in Attachment 3.

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[17]

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

[17] 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 - 2015_Business_Practice_ETP_Method_Criteria_and_Process_effective_12-7-15 (updated check)
2) PacifiCorp Engineering Handbook section 1B.4 - https://www.pacificpower.net/content/dam/pacific_power/doc/Contractors_Suppliers/Power_Quality_Standards/1B_4.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/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2%201.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	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 F
CC6						X		A B C D F
CC7					X			A B C D F
CC8							X	E+RPS
CC9		X					X	E+RPS
CC20		X	X				X	E+RPS
CC10						X		E+RPS
CC11		X				X		E+RPS
CC18		X	X			X		E+RPS
CC12					X			E+RPS
CC13			X		X			E+RPS
CC19		X	X		X			E+RPS
CC14		X	X		X	X		E+RPS
CC15			X		X		X	E+RPS
CC16		X				X	X	E+RPS
CC17		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 assumptions 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 uncommitted 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

Power flow software will be used to compare losses before and after a project is added to the system. In prior cycles, NTTG has used multiple power flows for this metric, this study cycle TWG will evaluate the use of the Production Cost software as an alternative and make a recommendation for its use in future study cycles. A reduction in losses after a project is added represents the benefit.

NTTG will compute annual energy loss using multiple power flow cases extracted from the production cost base case. The calculation will be dependent upon the case selection, since each power flow case can be used to represent some portion of the study year. The energy loss valuation will be based on average energy price for the study year.

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. 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[18] 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 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.

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

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 6 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 a 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[19] 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.

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

[19] 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 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 2. 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 uncommitted 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

Commented [SH4]: Prior to June 8, this section will be updated with an overview of the request and an attachment will be included describing the PPC Study Plan

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.

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 issued an	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 Category (3): 0-10% other/unbundled RECs		

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
				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.			
	Oregon	Large Utilities -- selling more than 3% of retail electricity in OR Applies to: PGE, PacifiCorp, and	"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"	5% by 2011 15% by 2015 20% by 2020 25% by 2025 50% by 2040 On March 8, 2016, Governor Kate Brown			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
		Eugene Water & Electric Board	a) Wind; b) Solar PV or thermal; c) Wave, tidal, ocean energy; d) Geothermal e) Biomass (specified types) Hydrogen-RE Resource must be operational on or after 1995	signed Senate Bill 1547-B (SB 1547-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 <u>Goal</u>: 20% by 2025			

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		No interim requirements, first 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	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
			shaping, storage, or integration services; 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
Interregional Transmission Project Coordination Timeline

The following table provides a proposed timeline[20] 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
9. Develop and post an ITP Evaluation Process Plan, including agreed to common study assumptions, data, methodologies, cost assumptions and a	June 14, 2018	No later than 75 days following the ITP submittal deadline

[20] 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.

	schedule for determining the selection of an ITP		
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[21]	Prior to December 31, 2019	Per the ITP Evaluation Process Plan, but no later than December 31, 2019

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[21] 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 3

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 of 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 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 1090 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 a 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.

Commented [RDS5]: The figures and analysis in this attachment will be updated once the ADS case has been vetted and ready for studies.

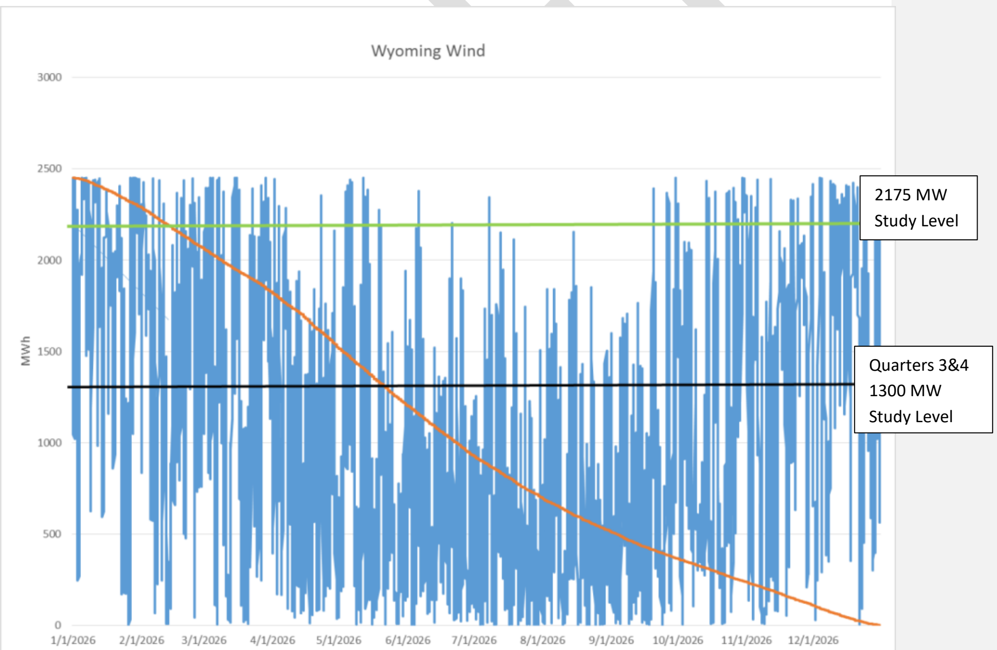

Figure 1: Chronologic and Duration curve of forecasted Wyoming wind production for 2026

Figure 2 below is a scatter plot of the Wyoming Wind production vs Wyoming Thermal production from the Production Cost Model which demonstrates that the two resources are independent and these levels needed to planned for in the RTP.

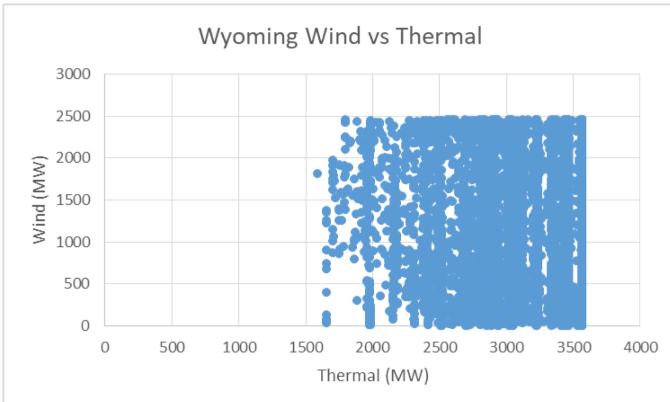

Figure 2: Scatter plot of Wyoming thermal vs Wyoming wind production for draft ADS PCM Case

Attachment 4
Public Policy Consideration Study Proposal for a Scenario Analysis:

Placeholder for approved PPC study plans

Commented [AW6]: Prior to June 8, this section will be updated with an overview of the request and an attachment will be included describing the PPC Study Plan

Attachment 5

Interregional Transmission Projects Evaluation Process Plans

Commented [RDS7]: Once ITP Evaluation Plans have been drafted and accepted by the relevant Planning Regions, those plans will be attached here.

ITP Evaluation Process Plan

SWIP-North

xxx xx, 2018

Placeholder for draft Evaluation Plan

ITP Evaluation Process Plan

Cross-Tie Transmission Line

xxx xx, 2018

Placeholder for draft Evaluation Plan

ITP Evaluation Process Plan

TransWest Express Project

xxx xx, 2018

Placeholder for draft Evaluation Plan

Attachment 6

NORTHERN TIER
TRANSMISSION GROUP

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 — April 30, 2018

Data within this table is under review and will be updated when the data is available

	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

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.

E. 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.

F. 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

Data within this table is under review and will be updated when the data is available — April 30, 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 — April 17 2019

Data within this table is under review and will be updated

	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

G. 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	Prorate MW *	Adjusted	2018 to 2028 Δ	Prorate MW **	Adjusted
	Wind	-800	2028	Solar	800	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

H. 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.

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.

	Allocation Scenario D: Replace Coal with Wind and Solar			
	Data within this table is under review and will be updated when the data is available			
	April 17, 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

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.

Revision History

Version	Date	Comment	Author
Version 1	4/12/18	Drafted	R. Schellberg
Version 2	5/2/18	Posted for Planning Committee	
Version 2c	5/3/18	Updated TOC & Posted for PC Review	A. Wachsnicht
Version 2d	5/9/18	Updated per recommendations during PC mtg	R. Schellberg
Version 2e	5/10/18	Posted for Stakeholder Comments	A. Wachsnicht