Revised NTTG Biennial Study Plan for the 2014-15 Regional Planning Cycle

This revised Biennial Study Plan outlines the process to be followed by the NTTG Planning Committee in performing the 2014-15 biennial regional transmission planning process, as required under FERC Order 1000, Attachment K – Regional Planning Process.

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I. Introduction

This revised 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 for the biennial planning cycle covering years 2014-2015. 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/or Quarter 5 of the Regional Planning Cycle, and will be considered in the development of the 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) 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. This revised Study Plan has been adjusted during the biennial study process to accommodate data updated during Quarter 5, additional reliability studies in (based on updated data), and to address transmission service obligations. These adjustments have been made after consultation with stakeholders and with appropriate NTTG approvals.

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. The TWG is comprised of individuals who are committed to achieve completion of the assignments in a cooperative and timely manner, and who have access to and expertise in power system power flow analysis or production cost modeling.

II. Study Objective

The objective of the transmission planning study is to produce the NTTG Regional Transmission Plan, through the selection of projects that yields a transmission plan that is more efficient or cost effective than other options, in compliance with Attachment K– Regional Planning Process.

[1] Capitalized terms in this document are from Attachment K definitions

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 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:** Evaluate the completeness of data received from stakeholders and resolve any deficiencies. Develop the Biennial Study Plan[2] for approval by the Steering Committee.
- **Quarters 3 and 4**: Analysis – The submitted system loads, resources, transmission projects, and alternative solutions will be modeled and technical screening studies will be performed to evaluate the Initial Regional Plan and Alternative Projects.
- **Quarter 5:** Draft study results – Stakeholders may review and comment on the Draft Regional Transmission Plan. Any stakeholder may also submit updated information about the data submitted in Quarter 1. The new submittals 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**: Stakeholder review of the DFRTP, and Regional Transmission Plan produced
- **Quarter 8**: NTTG Steering Committee approval and Regional Transmission Plan posted

IV. Study Assumptions and Representation

A. Major Study Assumptions and System Representation

1. Data Assumptions

The following load, resource, 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 and/or Quarter 5 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 2014 and updated data from Quarter 5 (1Q 2015) compared with loads that were forecasted in 2012.

[2] See Footnote 1

SUBMITTED BY:	2013 Actual Peak Demand (MW)	2021 Summer Load Data Submitted in Q1 2012 (MW)	2024 Summer Load Data Submitted in Q1 2014 (MW)	Difference (MW) 2021-2024	2024 Summer Load Data (MW) submitted in Q5 (2015)
Basin Electric	No Data Submitted	476	No Data Submitted		
Black Hills	No Data Submitted	465	No Data Submitted		
Idaho Power	3,407	4,383	4,193	-190	
NorthWestern	1,707	1,680	1,774	94	
PacifiCorp East	No Data Submitted	9,842	10,358	506	
PacifiCorp West	No Data Submitted	3,795	3,644	-151	
Portland General	3,900	4,119	3,933	-186	
TOTAL*		23,819	23,892	73	

* Does not include Basin Electric and Black Hills who didn't submit data in 2014

Table 1: January 2014 Data Submittal – Load Comparison

b. Resources: Resources provided in response to the Quarter 1 and/or the Quarter 5 data requests are incremental to existing resources within the NTTG footprint and are summarized in Figure 1 and Table 2 below.

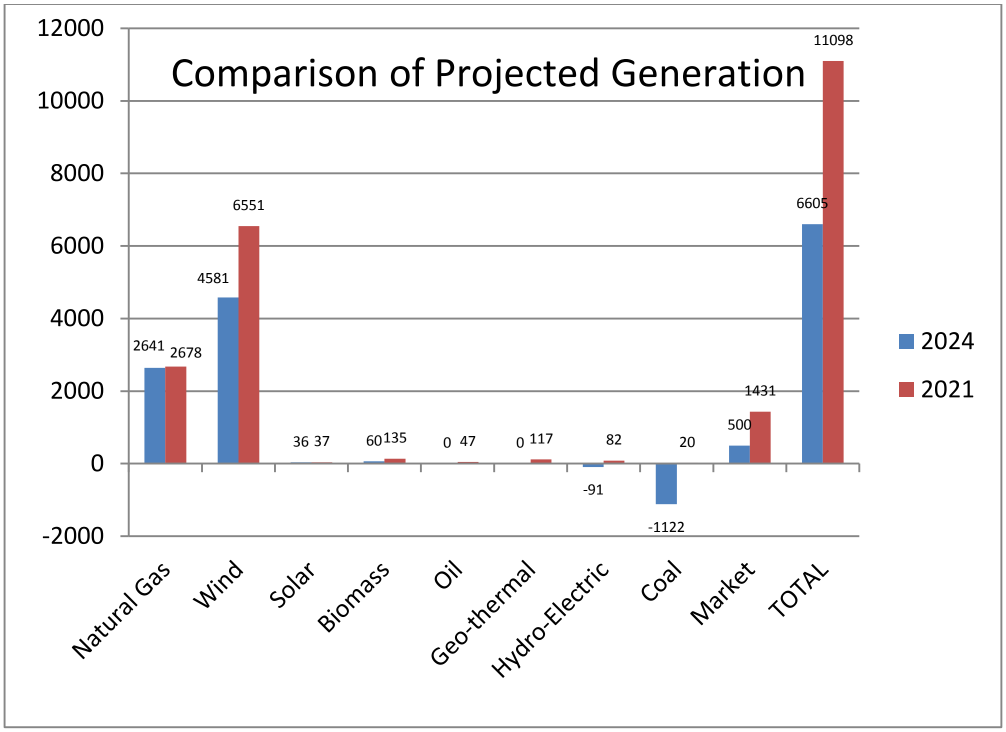

Figure 1: Comparison of Forecasted Resources

As shown in this figure, the total resource forecast of 6605 MW submitted this cycle is significantly reduced (~4500 MW) from the forecast in 2012. 500 MW of these resources represents market purchases which are not included in Table 2 below because the location is not determined.

State	Resource Additions (MW)
California	-81
Idaho	81
Montana	584
Oregon	68
Utah	1,467
Washington	278
Wyoming*	708

*Excludes the 3000 MW wind project submitted by Power Company of Wyoming

Table 2: Location of 2024 Forecasted Resources

The 3000 MW wind project submitted by Power Company of Wyoming will not be included in the Regional Transmission Plan studies as per the customer request.

c. Transmission Projects: Listed below in Table 3 are the new transmission projects that were submitted in Quarter 1 and/or Quarter 5. The project types may be either prior Regional Transmission Plan[3] (pRTP), Full Funder Local Transmission Plan (LTP), Sponsored Project, Unsponsored Project, or Merchant Transmission Developer. The Local Transmission Plan (LTP) projects submitted by the NTTG Funders will form the Initial Regional Transmission Plan.

[3] There were no new projects identified in the Regional Transmission Plan for 2012-2013.

JANUARY 2014 DATA SUBMITTAL – NEW TRANSMISSION BY 2024

Sponsor	From	To	Voltage	Circuit	Type	Projects
Idaho Power	Cedar Hill	Hemingway	500 kV	1	LTP	Gateway West Transmission Project
	Hemingway	Boardman	500 kV	1	LTP	B2H Project
	Midpoint	Borah	500 kV	1	LTP	(convert existing from 345 kV operation)
	Hemingway	Bowmont	230 kV	2	LTP	New Line
	Bowmont	Happy Valley	138 kV	1	LTP	New Line
	King	Wood River	138 kV	1	LTP	Line Reconductor
Great Basin Transmission	Midpoint	Robinson	500 kV	1	Sponsored	Southwest Intertie Project North
NorthWestern Energy	Broadview	Garrison	500 kV	1	LTP	Upgrade Series Comp. on existing line
	Millcreek	Amps	230 kV	1	LTP	Install Series Comp. on existing line
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP	Gateway South Project – Segment #2
	Aeolus	Jim Bridger	500 kV	1	LTP	Gateway West Transmission Project Segment 1A
	Jim Bridger	Populus	500 kV	1	LTP	Gateway West Transmission Project Segment 1B
	Populus	Borah	500 kV	1	LTP	Gateway West Transmission Project Segment 1C
	Windstar	Aeolus	230 kV	1	LTP	Gateway West Transmission Project Segment 1A
	Populus	Cedar Hill				
	Cedar Hill	Hemingway	500 kV	1	LTP	Gateway West Transmission Project
Portland General	Blue Lake	Gresham	230 kV	1	LTP	New Line
	Beaverton	Denny	115 kV	1	LTP	Reconductor
	Lincoln	Harrison	115 kV	1	LTP	Underground
	Orenco	Sunset	115 kV	1	LTP	Reconductor
TransWest Express	Wyoming	So. Nevada	600 kV	1,2	Merchant Transmission Developer	DC bipole transmission

Table 3 – New Transmission Projects

The transmission projects listed in the table above will be analyzed during this biennial Regional Planning Cycle. The Sponsored Projects will be evaluated through the use of Change Cases as described below. Additionally, Merchant Transmission Developer and unsponsored projects may be evaluated in Change Cases to produce the more efficient or cost effective Regional Transmission Plan.

The TransWest Express project will not be evaluated as an Alternative Project for selection into the Regional Transmission Plan studies as per the customer request. Alternative Projects will be included in Change Cases.

d. Transmission Service Obligations: Listed below in Table 4 are the new or existing transmission obligations that were submitted in Quarter 1 and/or Quarter 5.

Submitted by	MW	Start Date	End Date	POR	POD
Idaho Power	500	2020	-	Northwest	IPCo
	(67)	01/01/15	01/01/24	LGBP	BPASID
	2	04/01/15	04/01/28	LaGrande	BPASID
	5	07/01/16	07/01/28	LaGrande	BPASID
	(85)	10/01/11	10/01/28	LGBP	RR
	(100)	10/01/11	10/01/28	LGBP	OTEC
	(188)	10/01/11	10/01/28	LGBP	BPASID
	60	2020	-	Northwest	BPASID
NorthWestern Energy	39	7/1/2013	71/2018	YTP	BRDY
	7	7/1/2013	71/2018	NWMT.SYS	BRDY

Table 4 – Transmission Service Obligations

e. Available Transfer Capability (ATC): Listed in Table 5 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(*2015*)
8 – Montana to Northwest	E-W: 2200 W-E: 1350	E-W: 724 W-E: 706
14 - Idaho to Northwest	W-E: 1200 E-W: 2400	W-E: 0 E-W: 514
16 – Idaho - Sierra	N-S: 500 S-N: 360	N-S: 168 S-N: 0
17 – Borah West	E-W: 2557 W-E: 1600	E-W: 0 W-E: 1445
19 – Bridger West	E-W: 2400 MW W-E: 600 MW	E-W: 60* W-E: 200*
20 – Path C	N-S: 1600 S-N: 1250	N-S: 0 S-N: 0
37 - TOT 4A	NE-SW: 960	NE-SW: 0 SW-NE: 761
38 - TOT 4B	SE-NW: 880	SE-NW: 33 NW-SE: 104
75 - Hemingway-Summer Lake	E-W: 1500 W-E: 550	E-W: 0 W-E: 0

*** IPCO Share**

Table 5 – Transmission Path Capacity and Available Transfer Capability

2. Analysis Tools

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

Power flow – The PowerWorld 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 identified by Peak RC. 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.

Production Cost – Production cost studies are used to simulate the economic dispatch of resources to meet load during a given period of time (e.g., a year) and performed using security-constrained hourly chronological generator commitment and dispatch programs that find feasible and least-cost resource operations, which deliver electricity from generators to loads distributed across the same underlying transmission grid modeled in the power flow programs. The GridView[4]production costing software will be used to evaluate the range of production scenarios that may occur in the Western Interconnection. Production cost studies results will be used to define power flow base 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 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[5]) 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 base case, comprised of multiple hours within the study year, will be developed using the production cost model, 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.

[4] GridView is a production costing tool and product of ABB
[5] None were identified in the 2012-2013 planning cycle

The base case will consist of those load, resource and interchange data (the combination of input and output data) for these selected hours transferred from GridView to PowerWorld.

- Using the base case, the Initial Regional Plan will be evaluated using power flow analysis to determine if it meets the system performance requirements and transmission needs associated with Public Policy Requirements. If it fails to meet these minimum requirements, the deficiency(ies) will be identified. If one or more Alternative Projects are unlikely to correct the deficiency(ies) the TWG will develop one or more additional, unsponsored Alternative Projects that will correct the deficiency(ies) and 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 to the Initial Regional Plan. Each Change Case will also exclude one or more uncommitted projects in the Initial Regional Plan whose impacts are likely met by the Alternative Project incorporated in the Change Case.
- Analysis will be performed as needed to determine whether or not NTTG's transmission providers' future transmission system accommodate 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 5, 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 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.
- Those Change Cases will then be further evaluated using three 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.

- Those Alternative Projects in Change Cases which are more efficient or cost effective than the Initial Regional Plan based on the three metrics will be selected and combined into one or more additional Change Cases.
- When necessary, these combined 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 combined Change Cases meeting these minimum requirements, the monetized incremental cost will be determined using the three metrics. Based on review by the TWG of the results for the combined Change Cases, the process of developing and evaluating additional combined Change Cases from the Alternative Project initially selected may be repeated.
- Using the three metrics, the Alternative Projects, if any, from the combined Change Cases that are determined to likely be more efficient or cost effective will be selected into the Draft Regional Transmission Plan.

4. Transmission Needs Driven by Public Policy Requirements

Public Policy Requirements are those public policy 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[6] 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.

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

[6] See Attachment K, Local Planning process

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 Transmission Expansion Planning Policy Committee (TEPPC[7]) database will be reviewed and modified to assure conformance with the Initial Regional Plan.

2. System Conditions to Study

Production Cost Analysis - The NTTG TWG studies will extend beyond the traditional focus on snapshots of winter and summer peaks 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.

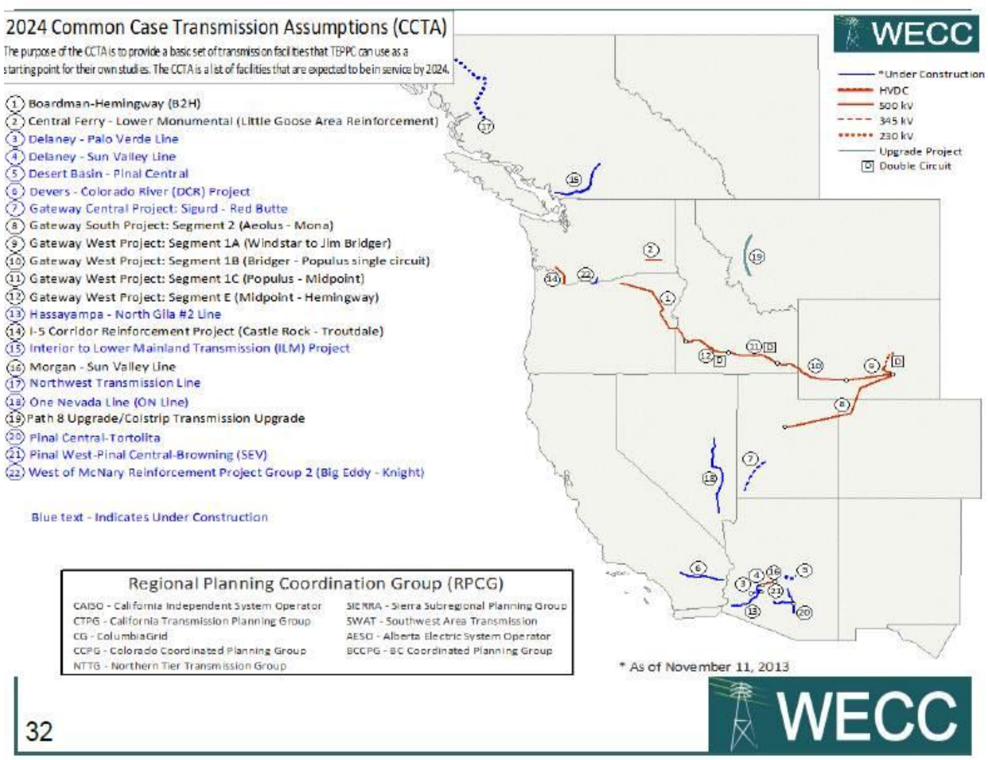

Figure 1 - CCTA

The WECC TEPPC 2024 common case production cost model will be analyzed for selection of hours for power flow analysis. This case includes 22 new transmission

[7] TEPPC 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.

projects called the Common Case Transmission Assumptions (see CCTA in Figure 1 above).

Using the TEPPC 2024 common case 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 maximum coincident NTTG net export;
d) conditions with minimum coincident NTTG export;
e) additional system conditions as needed to meet the needs of specific areas of the NTTG footprint

3. Power Flow Databases

a) Base Cases

The base cases representation 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 TEPPC 2024 case. The TWG will import the data for each system condition into the PowerWorld power flow program and create base cases for each of the study conditions.

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. The NTTG TWG studies will extend beyond the traditional focus on snapshots of winter and summer peaks to examine the change cases for situations where available resources and forecasted loads across the Western Interconnection cause highest stress on the transmission system in the NTTG footprint.

b) Change Cases

The TWG group will add any Alternative Projects and 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 System Review Work Group

(SRWG) – 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.

5. System Performance (Reliability) Criteria[8]

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 and TPL-002 b requires transmission facilities to operate within normal and emergency limits.

The WECC System Performance Regional Business Practice TPL-001-WECC-RBP-2 establishes the basis for voltage performance criteria. Although no steady state voltage limits are specifically identified in the Business Practice, 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

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 normal limits under normal conditions. The requirements for the pre-contingency performance criteria are summarized in the NERC's Transmission Planning standard TPL-001-0.1.
- ***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-002-0b.

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

- ***Credible Multiple Contingencies***–The 2014-2015 Regional Planning Cycle, the TWG will use all credible N-2 contingencies defined by Peak RC in the NTTG footprint. Power-flow simulation performance results require all transmission facilities to operate within normal and 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-003-0b.

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 - http://www.oasis.oati.com/NWMT/NWMTdocs/NWMT_2012-2013_Local_Area_Plan_Final_12-16-13.pdf
2) PacifiCorp Engineering Handbook section 1B.4 - https://www.pacificpower.net/content/dam/pacific_power/doc/Contractors_Suppliers/Power_Quality_Standards/1B_4.pdf
3) Others as Applicable

***NOTE**: NERC TPL-001 and TPL-002 system performance standards will be replaced by the new NERC TPL-001-04 reliability standard which was approved by FERC on 12/23/2013. Additionally, the WECC RBP requirements WR1, WR2, WR4 and WR5 will be retired and will be replaced.*

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 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.

The following analysis criterion will be used to determine if a Change Case is 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 TEPPC 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 TEPPC 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. 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 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.

There may be winners and losers when reviewing loss analysis, system performance, capital costs and reserves. 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 TEPPC 2024 base case. These base assumptions represent a pre-defined future that drives the 2024 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 2024 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

Following evaluation of projects by the Planning Committee, the Cost Allocation Committee would evaluate allocation scenarios,

- The allocation scenarios are developed by the Cost Allocation Committee (in consultation with the Planning Committee) with stakeholder input, for those parameters that will likely affect the amount of total benefits and their distribution among Beneficiaries as set forth in Attachment K, Section 19.2 [Allocation of Costs].
- When developing the Biennial Study Plan, the Planning Committee and Cost Allocation Committee will, under certain circumstances described in Attachment K, Section 20 [Reevaluation of Projects Selected in the Regional Transmission Plan], identify projects selected in the prior Regional Transmission Plan that will be reevaluated and potentially replaced or deferred.
- NTTG cost allocation analysis will incorporate alternative scenarios (relative to the Initial Regional Plan), with regard to those assumptions and parameters that likely affect the estimated distribution of project benefits in determining the cost allocation of a transmission project. To the extent feasible, the Cost Allocation Committee will look to the data underlying local transmission plans, resource planning studies (i.e. integrated resource plans) of LSEs within the NTTG footprint], the assumptions and the forecasts used to develop the alternative scenarios for each allocation metric. The selected alternative scenarios may vary (i.e., use a different set of alternative scenarios) among the benefit metrics and will focus on those assumptions and parameters for a benefit metric that affect the distribution of benefits for that metric among Transmission Providers, LSEs, and/or IPPs. The alternative scenarios for each cost allocation metric will likely include the following:
  - a) Capital Metric
    - i. Low and high load forecasts.
    - ii. New resource Location
  - b) Loss Metric
    - i. Low and high load forecasts.
    - ii. New resource Location
  - c) Reserve Metric
    - i. New resource Location
    - ii. Low and high gas forecasts

VII. Impacts on Neighboring Regions

All Initial Regional Plan and Change Case Plan(s) power flow studies will monitor the BES voltage and thermal loading in NTTG's neighboring planning regions (i.e., 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 Initial Regional Plan 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. Assuming this is a new violation caused by the Initial Regional Plan or Change Case plan, the study 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 <u>not</u> 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 Initial Regional Plan 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 Initial Regional Plan 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. 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 scenarios 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.

In Quarter 1 of the 2014-2015 Regional Planning Cycle, three requests for Public Policy Considerations were submitted:

1. The Renewable Northwest Project (RNP) submitted a request to study the effects of retiring Colstrip units 1 and 2 and replace with Montana wind resources in the year 2020;
2. The RNP requested a study to consider the effects of retiring Colstrip units 1, 2, 3 and 4 and replace with Montana wind in 2027, and
3. The Northwest Energy Coalition requested a study to reduce the output at various coal plans in Utah, Wyoming, and Colorado and replace with various renewable resources. No year was specified.

After deliberation, the TWG recommended proceeding only with the proposal from RNP to retire Colstrip units 1 and 2 and replace with Montana wind resources in 2020. The reasoning for this recommendation is the RNP proposal to study the effects of retiring Colstrip Units 1, 2, 3 and 4 in 2027 are beyond the NTTG 10 year planning horizon and outside the scope of the Regional Planning Cycle. The Northwest Energy Coalition request has already been studied by the WECC Transmission Expansion Planning Policy Committee. Since NTTG would use the same base case (as proposed by the submitter) and the same modeling techniques, different results would not be expected. Additionally, by re-doing the study and no additional information would be gained to inform the Regional Transmission Plan.

On June 13, 2014 the Planning Committee voted to support the above recommendation, and on June 23, 2014 the NTTG Steering Committee unanimously approved the 2014-2015 Study Plan including transmission needs driven by Public Policy Consideration for additional study analysis.

IX. [Draft/Final] Regional Transmission Plan

The Planning Committee shall produce a Draft Final Regional Transmission Plan by the end of Quarter 6. The projects selected into the Draft Final 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 Participating Utility	State	PPR, Overview	Discussion of how the NTTG Participant Addresses the PPR in their Local Plan	New transmission needed as a function of the PPR
Deseret Power Electric Cooperative	Utah	● Every 5 years our members have a requirement to complete an IRP for Western Area Power Administration as a result of their participation in the Colorado River Storage Project. Deseret assists in preparing this requirement.	Deseret assists in preparing the IRP for WAPA.	No
Idaho Power	Idaho	● No Public Policies enacted in the state of Idaho.	N/A	No
	Oregon	● Under the Oregon Solar Photovoltaic Program, Idaho Power is mandated by the state of Oregon to install 500 kW of utility scale solar generation in the state of Oregon by the year 2020. (Requirement specific to Idaho Power)	Idaho power has incorporated this requirement into the IRP process and there are no new transmission needs.	No
NorthWestern Energy	Montana	● 15% by 2015 ● Community Energy Renewable Project requires 45 MW	NorthWestern Energy currently meets the 15% required for the RPS. Energy Supply meets this requirement through their contracts with online Network Resources. NWE has supplied two CREP projects to NTTG with a total of 45 MW. These projects have signed agreements but are subject to PSC approval. Base cases include sufficient renewable energy.	No
PacifiCorp	California	● 20% by 2010 ● Average of 20% through 2013 ● 25% by 12/31/16 ● 33% by 12/31/20 and beyond ● Based on retail load for that compliance period	PacifiCorp's RPS requirements are itemized in their RPS resources by BA in the 2013 Integrated Resource Plan Update.	No
	Oregon	● At least 5% of load by 12/31/14 ● At least 15% by 12/31/19 ● At least 20% by 12/31/24 ● At least 25% by 12/31/25 ● Based on the retail load for that year ● Invest in 20 MW solar by 1/1/20200PGE, PacifiCorp and Idaho Power combined	PacifiCorp's RPS requirements are itemized in their RPS resources by BA in the 2013 Integrated Resource Plan Update.	No
	Washington	● At least 3% of load by 1/1/12 ● At least 9T by 1/1/16 ● At least 15% by 1/1/2020 ● Annual targets are based on the avearge of the utility's load for the previous two years	PacifiCorp's RPS requirements are itemized in their RPS resources by BA in the 2013 Integrated Resource Plan Update.	No
	Utah	● 20% by 2025 (must be cost effective) ● Annual targets are based on the adjusted retail sales for the calendar year 36 months prior to target year ● Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM	PacifiCorp's RPS requirements are itemized in their RPS resources by BA in the 2013 Integrated Resource Plan Update.	No
	Wyoming	● No known PPR enacted in the state of Wyoming.	N/A	No
Portland General Electric	Oregon	● At least 5% of load by 12/31/14 ● At least 15% by 12/31/19 ● At least 20% by 12/31/24 ● At least 25% by 12/31/25 ● Based on the retail load for that year ● Invest in 20 MW solar by 1/1/20200PGE, PacifiCorp and Idaho Power combined	PGE is meeting the current RPS requirement; PGE is adding an additional 267 MW of wind in SW Washington to meet the 2015 requirement.	No
Utah Associated Municipal Power Systems	Utah	● 20% by 2025 (must be cost effective) ● Annual targets are based on the adjusted retail sales for the calendar year 36 months prior to target year ● Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM	The TP for UAMPS is Pacificorp and any PPRs are addressed in Pacificorp's plan.	No

Revision History

Version	Date	Comment	Author
Version 1	6/23/14	Approved by NTTG Steering Committee	G. Coulam
Version 2	2/11/15	Revised by Technical Work Group	G. Coulam