NTTG 2014-2015

REGIONAL TRANSMISSION PLAN

Updated with revisions from September 24, 2015 stakeholder comments

and

October 13, 2015 Joint NTTG Planning and Cost Allocation Committee modifications

October 13, 2015

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Executive Summary

The 2014-2015 NTTG Regional Transmission Plan (RTP) proposes a strategy to meet the transmission needs of the NTTG region in year 2024. The plan aims to meet the region's future transmission needs more reliably, efficiently and cost-effectively than an Initial Regional Plan comprising a combination of the Funding Transmission Providers' local transmission plans.

NTTG used a two-year process of identifying transmission requirements, conducting reliability analysis and evaluation of the Initial Regional Plan and Alternative Projects, selecting the more efficient or cost-effective projects, and performing robustness analysis to arrive at a final RTP.

Technical planning studies showed that one Sponsored Project and one Alternative Project produced a more efficient or cost-effective regional transmission plan than the Initial Regional Plan. The Sponsored Project is a non-committed 500-kV line from Boardman, Ore., to the Hemingway substation in Idaho. The Alternative Project is a grouping of four transmission elements.

The Alternative Project was selected for cost allocation analysis. The sponsored Boardman to Hemingway 500-kV project did not request regional cost allocation. However, since all project costs could not be allocated to Beneficiaries, the Alternative Project was ineligible for cost allocation.

Stakeholder input on the RTP was accepted and evaluated throughout the biennial planning cycle. NTTG posted a final draft of the RTP in Quarter 6 of the biennial planning cycle for public comment. The Planning and Cost Allocation committees recommended submittal of the RTP to the NTTG Steering Committee in Quarter 7. The Steering Committee approved the RTP in Quarter 8.

Introduction

The Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) was formed in 2007 to promote effective planning and use of the multi-state electric transmission system within the Northern Tier footprint. Northern Tier provides a forum where all interested stakeholders, including transmission providers, customers and state regulators, can participate in planning, coordinating and implementing a robust transmission system.

NTTG fulfills requirements of the Federal Energy Regulatory Commission (FERC) Order 1000 for each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and has a regional cost-allocation method.

NTTG evaluates transmission projects that move power across the regional bulk electric transmission system, serving load in its footprint and delivering electricity to external markets. The transmission providers belonging to Northern Tier serve more than 4 million retail customers with more than 29,000 miles of high-voltage transmission lines. These members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, and parts of Washington and California.

NTTG works with other entities—the WECC Planning Coordination Committee for reliability planning, the WECC Transmission Expansion Planning Policy Committee (TEPPC) for economic analysis, and neighboring Planning Regions (e.g., ColumbiaGrid, WestConnect and CAISO).

Participating Utilities

Deseret Power Electric Cooperative
Idaho Power
NorthWestern Energy
PacifiCorp
Portland General Electric
Utah Associated Municipal Power Systems

Purpose of the Plan

The NTTG Regional Transmission Plan (RTP) aims to produce a more efficient or cost-effective regional plan to transmit energy compared with a plan that rolls up the local Transmission Providers' transmission plans and other Change Case transmission plans studied. This study process complies with FERC Order No. 1000, Attachment K—Regional Planning Process. Order 1000 also calls for allocating the cost of regional transmission solutions fairly to beneficiaries.

Plan Development Process

The Regional Transmission Plan is developed through a two-year process of 1) identification of the transmission requirement for the NTTG footprint, derived from the data submissions; 2) reliability analysis and evaluation of the Initial Regional Plan and Alternative Projects; 3) selection of the more efficient or cost-effective projects; and 4) robustness analysis of the Final Regional Transmission Plan.

Biennial Cycle

NTTG followed a two-year, eight-quarter planning cycle to produce the 10-year Regional Transmission Plan. The biennial cycle includes steps to collect, evaluate and analyze transmission and non-transmission data, produce and publish a draft plan, gather stakeholder and public input, update the plan and complete the cycle with the publishing of a final transmission plan. The planning cycle starts with the Planning and Cost Allocation Committees pre-qualifying[1] Transmission Developers who submit a transmission project to be considered for regional cost allocation, should the sponsor's project be selected in the Regional Transmission Plan for cost allocation.

Data Submission

The Planning Committee accepted Transmission Provider data and stakeholder project data to be considered as part of the preparation of the RTP. NTTG's Funding Transmission Providers and stakeholders submitted the following six sponsored transmission projects[2] for consideration in the development of the RTP.

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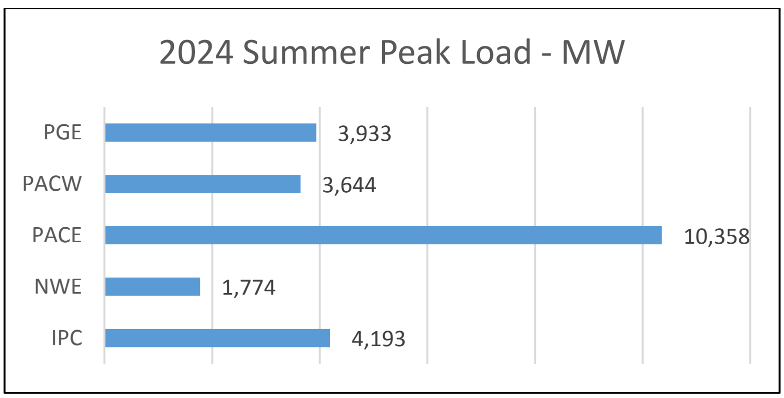
[1] A project sponsor must be pre-qualified their project by the Planning Committee prior to the beginning of the 2014-2015 biennial planning cycle (i.e., the last quarter of the prior planning cycle) pursuant to Attachment K, Section Pre-Qualification for Cost Allocation.

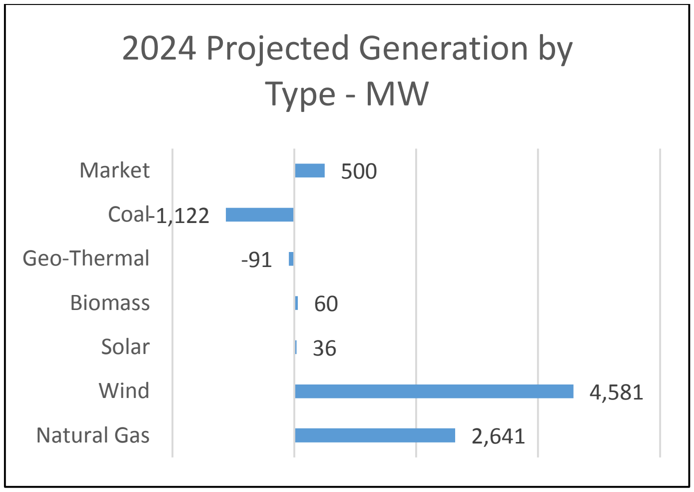
[2] Some of the transmission projects that were submitted were local transmission projects that were not consider in the regional transmission planning process (or shown in the table).

Sponsor	Type	Projects	Voltage	Circuits
Idaho Power (uncommitted)	LTP	Gateway West Project	500 kV	2
	LTP	B2H Project	500 kV – 230 kV	2
Great Basin Transmission (uncommitted)	Sponsored (1)	Southwest Intertie Project North	500 kV	1
NorthWestern Energy	LTP	Broadview – Garrison Upgrade	500 kV	1
	LTP	Millcreek – Amps Upgrade	230 kV	1
PacifiCorp East (uncommitted)	LTP	Gateway South Project	500 kV	1
	LTP	Gateway West Project	500 kV – 230 kV	5
Portland General	LTP	Blue Lake - Gresham	230 kV	1
TransWest Express (uncommitted)	Merchant Transmission Developer (2)	TransWest Express	±600 kV DC	1

The forecasted loads for Balancing Authority Areas internal to the NTTG footprint were also provided to NTTG during Quarter 1. These load forecasts were 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.



NTTG received 6,606 MW of proposed new generation resources from its Funding Transmission Providers for consideration in the RTP. The following graph displays these incremental resources within the NTTG footprint.



NTTG also received two new potential resource additions during the Quarter 5 data submittal window: a 540-MW nuclear-energy project submitted by Utah Associated Municipal Power Systems and a 451-MW renewable resource submitted by Idaho Power. These new generation projects were considered to the extent feasible without delaying the development of the RTP. They were reviewed using power-flow analysis, and these high-level results were noted in the plan. These generation projects will be carried forward for consideration in the 2016-2017 Planning Cycle if they are properly submitted during the Quarter 1 2016 data-submittal window.

In support of the proposed transmission additions or upgrades, NTTG received firm transmission-service obligations (legal or contractual requirements to provide service): 750 MW from the Pacific Northwest to Idaho Power, received from Idaho Power and Bonneville Power Administration; and 46 MW from Montana to Idaho Power, received from Northwestern Energy. These are shown in the following map.

Public Policy Consideration Scenario Requests

NTTG received three Public Policy Consideration study requests. Renewable Northwest Project (RNP) submitted a PPC request for a scenario analysis to assess the 2020 retirement of Colstrip Power Plant (Colstrip) units 1 and 2 (305 MW net per generator after accounting for auxiliary load) and integration of 610 MW of replacement wind resources at the Broadview substation in Montana. NTTG accepted this PPC request for study. RNP also submitted a PPC request to retire Colstrip Units 3 and 4 in 2027, but NTTG denied the PPC request as it was beyond the planning study horizon. In addition, NW Energy Coalition submitted a PPC request to study the accelerated phase-out of coal plants and a concurrent enhancement of new clean energy resources. This PPC request was not accepted for study as it had already been performed by the WECC TEPPC.

Regional Economic Study Requests

NTTG received three economic study requests for consideration. Two of these requests were submitted after the study window closed and were not pursued by the Planning Committee. The third was a request to retire Colstrip Units 1 and 2 (approximately 600 MW net) and replace with 1,000 MW wind and 400 MW pumped hydro. The Planning Committee declined to pursue this study request because points of receipt and points of delivery overreached the NTTG footprint.

Biennial Study Plan

The Biennial Study Plan (study plan) outlines the process that NTTG followed to develop its 10-year Regional Transmission Plan (RTP). It provided the framework to guide RTP development. The NTTG Planning Committee manages the study plan. The Planning Committee established the Technical Work Group (TWG) subcommittee to develop the study plan and perform the necessary technical evaluations for the RTP. TWG members have access to and expertise in power-flow analysis for power systems or production-cost modeling, or both.

Developed during Quarter 2 of the biennial planning cycle, the study plan established the:

- Study methodology
- Study assumptions based on the load, resource, transmission service obligations, transmission projects and transmission alternatives received during the data submission period
- Production cost and power flow analysis software tools
- 2024 Production cost model database and the hours selected for reliability analysis
- Reliability and transmission service obligation evaluation criteria
- Capital Cost, energy losses and reserves sharing metric calculations
- Resolution of Public Policy Consideration requests

The study plan was posted for stakeholder comment, recommended for approval by the Planning Committee and approved by the Steering Committee during Quarter 2 of the biennial cycle.

Creation and Evaluation of Initial Regional Plan

Under the direction of the Planning Committee, the TWG's first step in developing the Biennial Study Plan was to identify an Initial Regional Plan. The Initial Regional Plan took shape through a bottom-up approach by aggregating the Funding Transmission Providers' local transmission plans into a single regional transmission plan. Next, the TWG developed Change Case plans. These plans were used to determine whether or not the non-committed projects[3] (i.e., Boardman to Hemingway Project and Energy Gateway project) were needed to meet the 2024 transmission needs, or if there were Alternative Projects that would provide a reliable transmission plan that was more efficient or cost effective. Projects in the Initial Regional Plan included the non-committed projects mentioned above, as well as series capacitor upgrades in Montana, as described in the map below.

[3] Non-committed projects lack all permits and rights of way required for construction by the end of Quarter 1 of the current Regional Planning Cycle.

Boardman to Hemingway Project. This non-committed project entails a new 500-kV line from Idaho Power's Hemingway Substation, about 10 miles southwest of Melba, Ida., to a new substation near Boardman, Ore.

Energy Gateway Project. This non-committed project consists of Boardman to Hemingway, Gateway West and Gateway South. The Gateway West component is composed of a new 230-kV transmission line from the Windstar substation, near Glenrock, Wyo., to the Aeolus substation in southeastern Wyoming, and 500-kV lines from the Aeolus Substation to the Hemingway Substation. The Gateway South segment spans from Aeolus Substation to Clover Substation near Mona, Utah.

The TWG then conducted a reliability analysis of the Initial Regional Plan and the Change Case plans. Reliability analysis sought to determine whether non-committed projects or Alternative Projects (including unsponsored projects) might yield a more efficient or cost-effective regional transmission plan. Two Alternative Projects were studied—the Southwest Intertie Project North (SWIPN) and an Alternative Project from Aeolus to Anticline to Populus.

The Change Case built a scenario in which one or more Alternative Projects displaced (either deferred or replaced) one or more non-committed projects in the Initial Regional Plan, while still meeting all regional transmission needs, reliability standards and Public Policy Requirements. This process determined if a Change Case was a more efficient or cost-effective solution for the NTTG footprint than the Initial Regional Plan project. Each Change Case was then compared against the Initial Regional Plan for the tenth year of the 10-year planning horizon.

The projects—either from the Initial Regional Plan or from the Change Cases—that defined the more efficient or cost-effective regional transmission plan, as measured by capital costs, losses and reserve margin, and adjusted by their effects on neighboring regions, were then incorporated within the Draft RTP. Eligible projects incorporated within the Draft RTP were then evaluated for cost allocation by the Cost Allocation Committee.

Study Cases

Identification of Stressed Hours for Study with Production-Cost Modeling

The TWG used GridView[4] production-cost software to review 8,784 hours (2024 is a leap year) of data to identify stressed conditions within the NTTG footprint. A case representing the year 2024 was obtained from the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electric Coordinating Council (WECC). This case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system 10 years in the future. The TWG accepted the TEPPC 2024 database as a reasonable representation for the Initial Regional Plan.

[4] GridView is a registered ABB product

The TWG studies extended beyond the traditional focus on snapshots of winter and summer peaks. Instead, the TWG examined all hours of the year for situations where available resources and forecasted loads across the Western Interconnection caused highest stress. This included periods of peak load and high transfers with other regions on the transmission system in the NTTG footprint.

After running all 8,784 hours through the production-cost program, the data were analyzed and the hours representative of the five stressed conditions were identified:

- Maximum NTTG export
- Minimum NTTG export (import)
- Maximum NTTG summer peak
- Maximum NTTG winter peak
- Maximum flow from Montana to the Northwest (Path 8 in WECC Path Rating Catalog)

Reliability Analysis with Power-Flow Modeling

The TWG performed reliability analysis to establish whether proposed transmission additions could reliably meet forecasted load and resource portfolios at anticipated stress times in 10 years. The reliability studies used production-cost modeling to define the hours of stressed conditions of interest, and power-flow studies to analyze the reliability of these stressed conditions.

Criteria

After analyzing the steady-state performance of each of the five stressed conditions, the TWG ran a rigorous contingency analysis. Power-flow analysis was performed on the developed cases to determine if any voltage- or thermal-overload violations existed under two conditions: system normal (all lines in service, N-0 pre-disturbance analysis) and with transmission elements out of service (contingency analysis). The contingency analysis included both one element (N-1) and two transmission elements out of service at a time (credible N-2).

This contingency analysis consisted of 400 N-1 contingencies and 39 credible N-2 contingencies, to determine if each contingency met the system performance criteria. The contingencies were applied to all transmission elements, 230 kV and above, and credible N-2 contingencies, as defined by reliability coordinator PEAK Reliability, in the NTTG footprint. During this analysis, autotransformer taps and phase-shifting transformers were not allowed to adjust (locked), and the switching of shunts and tie lines was disabled. Remedial Action Schemes (RAS) were executed for contingencies that normally utilize RAS. Transient stability and reactive margin analyses were not performed for this study.

The power-flow simulation results were measured against North American Electric Reliability Corp. (NERC) and WECC reliability criteria, as described in the Study Plan.

If legitimate reliability violations were found, the TWG determined what additional facilities were needed to meet the criteria and adjusted the Initial Regional Plan to include the additional facilities.

Absent violations, the facilities proposed in the Initial Regional Plan were deemed adequate for serving the NTTG loads and resources in the year 2024. The results of each of the five stressed cases are discussed below.

NTTG Export Case

This case reflected an export from the NTTG area of approximately 1,531 MW, NTTG area load of 16,512 MW and NTTG generation of 18,043 MW. The N-0 or steady-state performance analysis resulted in two thermal violations on local 115-kV systems in the Pacific Northwest, which will be resolved by local plans in the next 10 years. All of the contingency results met system performance criteria.

NTTG Import Case

The NTTG load and generation for this import case were 12,211 MW and 11,683 MW, respectively. The case yielded an NTTG area net import of approximately 528 MW. The steady-state conditions of this case showed a few high voltages on local 69-kV systems, which will be resolved through local plans over the next 10 years. Otherwise there were no steady-state violations. The results of the contingency analysis showed no violations of the performance criteria.

NTTG Summer Peak Case

This case had an NTTG summer peak load of 21,789 MW, with 19,619 MW of generation and an import of 2,170 MW. In this case there were also a few steady-state high voltages on local buses (< 20 kV) to be resolved in future local plans. Otherwise there were no other steady-state violations. There were no contingency results that violated the performance criteria.

NTTG Winter Peak Case

The NTTG winter peak load in this case was 19,033 MW, with 16,784 MW of generation and an import of 2,249 MW. The steady-state results showed some voltages outside of the acceptable range on local lower voltage buses in the Pacific Northwest. These were assumed to be resolved through the local plans. The results of the contingency studies showed no system-performance criteria violations.

Maximum Path 8 Case

This case had a Path 8 flow of 2,076 MW. The NTTG load and generation in this case were 10,712 MW and 13,319 MW, respectively. The NTTG total export was 2,607 MW. The steady-state results in this case showed several voltages and line/transformer overloads on the local lower voltage system in the Northwest. These will need to be resolved through the local plans. The results of the contingency studies showed no reliability violations.

Public Policy Considerations Study

As described above, NTTG accepted one Public Policy Consideration request for study. Renewable Northwest Project (RNP) submitted a PPC request for a scenario analysis study to assess the 2020 retirement of Colstrip Power Plant (Colstrip) units 1 and 2 (305 MW net per generator after accounting for auxiliary load) and integration of 610 MW of replacement wind resources at the Broadview substation in Montana.

In addition, the NW Energy Coalition submitted a PPC request to study the accelerated phase-out of coal plants and a concurrent enhancement of new clean-energy resources. This PPC request was not accepted for study because this study had already been performed by WECC TEPPC.

Two base cases derived for NTTG's Regional Transmission Plan were used for the Public Policy Consideration request analysis. The cases were the NTTG Summer Peak Case and the Maximum Path 8 Case. Power-flow studies were evaluated using steady-state (N-0), single-contingency (N-1) and credible double-contingency (N-2) conditions to ensure the transmission system met the system performance requirements defined in the planning standards. The analysis showed that under the steady-state conditions studied, assuming a MW-for-MW online exchange in generation, and proper generator tripping (either the wind machines at Broadview or the Colstrip units), wind generation interconnected to the 500 kV bus could possibly replace coal-fired generation at Colstrip. However, the study could not definitively conclude that the wind-for-coal replacement was possible. Nor did the analysis suggest or imply that a one-for-one substitution of wind for coal was feasible without further analysis or system improvements. It was noted that the study assumptions only give a limited conclusion and that with transient studies, using a dynamics-ready case and the actual ATR simulation program would be the next step in confirming the assumptions made of the ATR for this study.

Development of the Regional Transmission Plan

Guided by the 2014-2015 Biennial Study Plan, the TWG began the technical studies that would ultimately define the RTP. The RTP development process started with reliability studies on the Initial Regional Plan and Change Case plans to ensure that each transmission plan was reliable and adequate to meet the 2024 electrical needs of the loads, resources, public policy requirements, and transmission service obligations within NTTG's footprint. The plan that minimized the dollar sum of three benefit metrics and met the 2024 transmission needs was identified as the RTP. This process is described below.

Reliability Analysis

The TWG developed Change Cases to determine whether the non-committed projects in the Initial Regional Plan (i.e., Boardman to Hemingway project and Energy Gateway project) were needed to meet the 2024 transmission needs. This became Change Case 1. The TWG also studied whether an Alternative Project(s) would produce a more efficient or cost-effective regional transmission plan than the Initial Regional Plan. These were identified as Change Cases 2-7. The following table displays the Change Cases considered.

Change Cases Considered				
	Energy Gateway	Boardman to Hemmingway	SWIP North	Alternative Project
Initial Regional Plan	X	X		
Change Case 1				
Change Case 2		X	X	
Change Case 3				X
Change Case 4	X	X	X	
Change Case 5	X		X	
Change Case 6			X	X
Change Case 7 (1)		X		X
1. Change Case 7 Alternative Project is a similar but a larger project than the other Change Cases Alternative Project.				

The Alternative Projects used in the Change Cases could add to or displace (either defer or replace) one or more non-committed projects in the Initial Regional Plan. All Change Cases met all regional transmission needs, reliability standards and Public Policy Requirements. The projects—either from the Initial Regional Plan or a Change Case plan—that defined the more efficient or cost-effective regional transmission plan, as measured by the three benefit metrics (capital related cost, losses and reserves), adjusted by their effects on neighboring regions, were included in the RTP.

Boardman to Hemingway Project

A Change Case was created with this project removed (i.e., removed from each of the stressed-hour conditions studied) and no Alternative Project added. There were no Alternative Projects submitted during the Q1 data-submittal period, nor did the TWG identify an Alternative Project to replace this project during the technical analysis. The results of the Change Case power-flow analyses for system-normal analysis and contingency analysis did not identify any voltage or thermal-overload violations.

Energy Gateway/Boardman to Hemingway Project

A Change Case was created with the combined Energy Gateway and Boardman to Hemingway project removed and no Alternative Project added. There were no Alternative Projects submitted during the Q1 data submittal period to replace these projects. As described below, the reliability analysis identified a significant number of reliability violations.

Southwest Intertie Project North (SWIP North)

Great Basin Electric submitted the Southwest Intertie Project North (SWIP North) as a Sponsored Project to be considered for regional cost allocation, if it was selected in the regional transmission plan. This Alternative Project consisted of a new 500-kV line from Midpoint substation, north of Jerome, Idaho, to the Robinson Substation near Ely, Nevada. In addition, a 500-kV line from Harry Allen Substation, northeast of Las Vegas, to the Eldorado Substation in southern Nevada, was added to this case. Change Cases with the SWIP North project added to various stressed-condition cases were developed. These Change Cases were then analyzed using power-flow analysis. A comparison of the study results with and without the SWIP North project showed some improvement in the post-contingency voltages. However, voltage levels before adding the SWIP North project were already within acceptable voltage- and thermal-overload performance ranges in the cases. Also, Change Cases 2 and 5 found that the SWIP North project did not yield a transmission plan that was more efficient or cost-effective than a plan without the SWIP North project. Therefore, the SWIP North project was not selected in the Regional Transmission Plan.

The reliability analysis of the Initial Regional Plan found that each of the stressed cases for the selected hours met system performance criteria at steady-state and contingency conditions. Thus the question became whether the non-committed projects in the Initial Regional Plan (i.e., Boardman to Hemingway project and Energy Gateway/Boardman to Hemingway project) were needed or if an Alternative Project (including the SWIP North project) would yield a more efficient or cost-effective regional plan. The analysis looked at two Change Cases with the non-committed projects removed as well as a Change Case for SWIP North.

As noted above, the reliability analysis for Change Case 1 studied the existing transmission system by removing the non-committed Energy Gateway and Boardman to Hemingway projects from the Initial Regional Plan. The Quarter 3-4 reliability analysis determined that the transmission plan was reliable except in the export stress condition. In this instance, an overloaded line from NTTG to WAPA was resolved by an unsponsored Alternative Project. However, the Initial Regional Plan was updated in Quarter 5 with higher loads and additional wind resources in the PACE area and additional reliability studies were performed. Results of these studies showed an increase in the number of reliability violations.[5] This increase prompted several Alternative Projects (i.e., variants of the Quarter 3-4 Alternative Project) to be studied in Change Cases to define the Regional Transmission Plan that was more efficient or cost effective than the other Change Case regional transmission plans studied. Thus, the

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Draft RTP w/Q5 L&R	Thermal Violations	Voltage Violation
Summer	21	14
Winter	2	22
Export	16	13

reliability analysis found the need for improvements to the existing transmission system to meet 2024 transmission needs.

The reliability analyses of Change Cases 2-6 tested whether an Alternative Project would yield a more efficient or cost-effective transmission plan than the Initial Regional Plan's non-committed projects. If a Change Case proved unreliable for any stressed condition and needed mitigation (system fixes) to correct an overload or voltage violation under system normal or contingency analysis, then the cost of this mitigation was added to the capital cost of the Alternative Projects in the Change Case. There were no impacts to neighboring Planning Regions for any of these mitigated Change Cases.

Change Case 7 was the result of the reliability work described above and the Available Transmission Capacity analysis (described below) that was completed after the benefit metric analysis (also described below). This analysis determined if the existing transmission path had adequate capacity to meet the transmission service obligation. The study demonstrated the need for the Boardman to Hemingway Project in the RTP to satisfy firm transmission-service obligations. There were no impacts to neighboring Planning Regions for this Change Case. Change Case 7 ultimately became the RTP.

Transmission Needs and Available Capacity Analysis

During the course of developing the RTP, the TWG recognized that the technical analysis did not adequately account for the transmission needs associated with the Transmission Providers' firm transmission-service obligations. The resolution was to conduct an analysis of the relevant transmission path's Available Transmission Capacity (ATC). This analysis examined whether Idaho Power's firm transmission-service obligation, which designated the use of existing Path 14 (see table below) from the Pacific Northwest to Idaho, could be met in 2024 without the Boardman to Hemingway project added. The following table shows the results of this analysis. The existing Idaho to Northwest path has 0 MW west-to-east available transfer capability. This means that current firm transmission-service obligations could not be met by the existing Idaho to Northwest transmission path.

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 | W-E: 600	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

The results of this comparison demonstrated the need for the Boardman to Hemingway Project in the RTP to satisfy the transmission needs of Idaho Power. As a result of this study, the Change Cases that did not include the Boardman to Hemingway transmission project were deemed unacceptable.

The technical study results were then applied to three benefit metrics to analyze the Initial Regional Plan and the Change Case plans. The benefit metrics, derived from the Biennial Study Plan, included capital-related costs, line losses and reserves. The combination of some or all of the Initial Regional Plan's non-committed projects or Alternative Projects that provided the most efficient or cost-effective transmission plan were included in the RTP. The economic evaluations for the Initial Regional Plan and the Change Cases are discussed below.

Capital-related Cost Metric

Development of the capital-related cost metric required three steps: 1) validate the Project Sponsor's Q1 submitted project capital cost, 2) calculate the annual capital-related costs, and 3) compute the total present value of annual capital-related costs for the Initial Regional Plan and the Change Case plans. A change in annual capital-related costs between a Change Case and the Initial Regional Plan captures benefits related to transmission needs driven by both reliability and Public Policy Requirements. This benefit metric reflects the extent that a project in the Initial Regional Plan can be displaced while the plan meets all regional transmission needs and reliability standards. The capital cost of the transmission projects was converted to annual capital-related costs representing the sum of annual return (both debt and equity related), depreciation, operation and maintenance expense, and income and other taxes.

Change in System Losses

The energy-loss metric captured the change in energy generated, based on system topology, to serve a given amount of load. Using power-flow software, NTTG footprint losses were evaluated with and without a given non-committed or Alternative Project in service. A reduction in losses after a project was added represented a benefit, because less energy was required to serve the same load.

Five NTTG stressed-hour-conditioned cases were evaluated with and without a project in service. The net change in energy losses was determined for each case. The net losses for the five cases were then averaged to determine an average MW loss value. Next, the average MW loss value was annualized and multiplied by a 2024 nodal energy price extracted from the WECC 2024 TEPPC model to produce an annualized energy-loss benefit in dollars.

Change in Location of Reserves

The reserve metric evaluated the opportunities for two or more parties to economically share a generation resource that would be enabled by transmission. The metric provided a 10-year incremental look at the increased load and generation additions in the NTTG footprint and the incremental transmission additions that may be included in the RTP.

In the study cycle, Gateway West, Gateway South, Boardman to Hemingway, SWIP North and a Montana-NW upgrade were included in the analysis. To evaluate these projects, the NTTG footprint was segmented into five zones, and a sixth external zone was included to study SWIP North. Of the 34 viable power-sharing combinations, the analysis of the annual net savings over the standalone alternative suggested that only six viable combinations were economic. The viable combinations were further cut by half, to three, after the costs associated with SWIP South, the most likely location for a reserve resource, were included. This metric included generation capital costs in its evaluation. As such, the metric may only be appropriate for cost allocation and should not drive the selection of a base plan. Whether these cost savings warrant jointly sharing the costs of reserve capacity would be left to the parties to decide.

Metric Analysis Conclusion

The sum of the annual capital-related cost metric, loss metric (monetized) and reserve metric (monetized) calculated an incremental cost for the Initial Regional Plan and the Change Case plan. The set of projects (either the Initial Regional Plan or a Change Case plan) with the lowest incremental cost, after adjustment by the plan's effects on neighboring regions, were incorporated within the RTP. As described earlier, the Change Cases that did not include be Boardman to Hemingway project were not viable plans because there was insufficient available transmission capacity on the designated transmission path to meet the firm transmission service obligation. The following table shows the results of the metric analysis, which concludes that Change Case 7 has a lower annual increment cost than the Initial Regional Plan and as such was deemed the more efficient or cost-effective regional plan. Thus, Change Case 7 was deemed to be NTTG's RTP.

Metric Analysis Incremental Cost				
	Levelized Capital Related Cost	Annual Monitized NTTG Losses	Annual Monitized Reserve	Annual Incremental Cost
Initial Regional Plan	$521,402,647	$87,882,729	$0	$609,285,376
Regional Transmission Plan (Chanage Case 7)	$360,580,734	$88,893,318	$0	$449,474,052

Robustness Analysis

A robustness analysis of the RTP using the four cost-allocation scenarios (described below) was completed. Two of these scenarios varied the load in the NTTG footprint by +/- 1000 MW. The two other scenarios looked at different system conditions by displacing wind or coal generation with other renewable resources. The results of the robustness analysis suggested no change was needed to the non-committed regional transmission projects in the RTP. That is, these additional studies demonstrated the robustness of the RTP to reliably meet the transmission needs of a variety of load and resource alternatives in the future.

Projects Selected for the Regional Transmission Plan

Results of the technical planning studies showed that one Alternative Project, along with the Boardman to Hemingway 500-kV project, produced a more efficient or cost-effective regional transmission plan than the Initial Regional Plan.

The Alternative Project comprises the following transmission elements:

- 230-kV line from Windstar to Aeolus in central Wyoming and reinforcements to existing underlying transmission facilities
- 500-kV line from Aeolus to Clover near Mona, Utah
- 500-kV line from Aeolus to Anticline (Bridger) to Populus
- 345-kV line from Anticline to Bridger

Since the unsponsored Alternative Project was identified through the technical analysis, it was eligible to be considered for regional cost allocation.

The sponsored Boardman to Hemingway 500-kV project did not request regional cost allocation.

Cost Allocation Process

The NTTG Cost Allocation Committee (CAC) is charged with the task of allocating costs of selected projects to Beneficiaries. The RTP included one unsponsored Alternative Project for purposes of regional cost allocation. This project met the required minimum estimated cost of $20 million.

Projects Submitted for Cost Allocation

During NTTG's 2014-2015 biennial planning cycle, two transmission projects were considered for selection into the Draft Final RTP for purposes of regional cost allocation:

- A sponsored project submitted by Great Basin Transmission, LLC, an affiliate of LS Power, for its SWIP North transmission project. Reliability and economic analyses indicated that SWIP North failed to meet the more-efficient or cost-effective criteria and was not selected into the Draft Final RTP. This project was ineligible for cost allocation.
- The second project, the unsponsored Alternative Project, was identified by NTTG in the planning process and selected in the RTP for purposes of regional cost allocation. The regional cost allocation methodology was applied to this unsponsored Alternative Project, but ultimately the project did not receive cost allocation for the reason described below.

Cost Allocation Scenarios

Four cost allocation scenarios were developed by the Cost Allocation Committee for those parameters that likely affect the amount of total benefits of a project and their distribution among Beneficiaries. The variables in the cost allocation scenarios include, but are not limited to, load levels by load-serving entity and geographic location, fuel prices, and fuel and resource availability. The potential impact of uncertainties is estimated and incorporated in the calculation of net benefits used in cost allocation. This process is intended to provide an overall range of future costs used in determining a project's benefits and Beneficiaries.

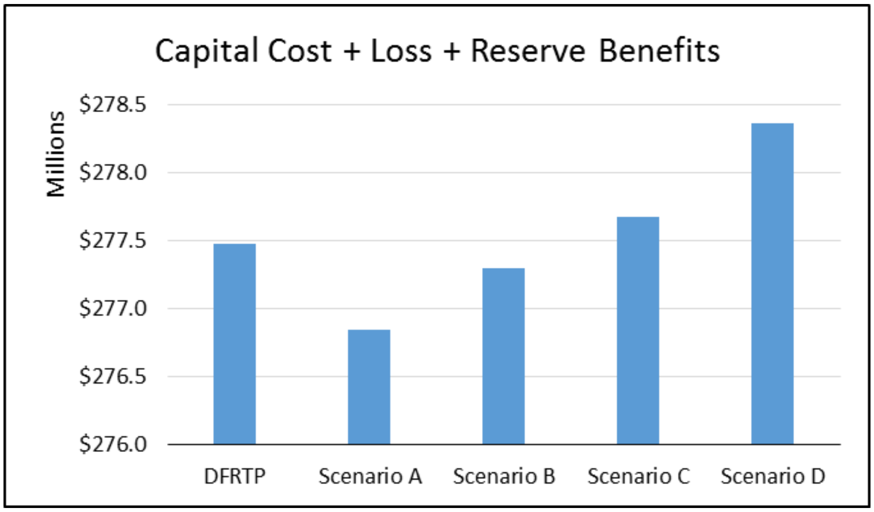
Scenario A: Add 1,000 MW of NTTG load in the NTTG footprint for a high-load scenario. Allocate the 1,000 MW to each Balancing Authority Area (BAA) based on the 2013/2014 actual peak demand and the projected 2024 peak demand.

Scenario B: Subtract 1,000 MW of NTTG load in the NTTG footprint for a low-load scenario. Allocate the 1,000 MW to each BA based on the 2013/2014 actual peak demand and the projected 2024 peak demand.

Scenario C: Remove 1,600 MW of wind capacity (2024 Q1 data projection, less the 3,000 MW wind project capacity submitted by Power Company of Wyoming), cut wind by 50 percent and replace with solar energy.

Scenario D: Subtract 1,000 MW of coal and presume units that are not retired in the 2024 case can be reduced pro rata and replaced with an equivalent amount of energy in equal shares of wind in Wyoming and Montana and solar in Idaho and Utah.

After the Cost Allocation Committee defined the cost allocation scenarios, the Planning Committee conducted N-0 power-flow analysis to validate the need for the Alternative Project in each scenario and to ensure that each scenario remained reliable. The TWG followed the Cost Allocation Study Plan and used the results from the power-flow analysis to calculate three metrics—capital cost benefit, line loss benefit and reserve margin benefit – for each cost allocation scenario.



These metric results were used by the Cost Allocation Committee's cost allocation methodology to allocate the Alternative Project costs to its Beneficiaries. Each metric was expressed as an annual dollar change in costs (or revenue). A common year was selected for net present value calculations for all cases to enable a comparative analysis between the RTP and the four cost allocation scenarios. As described above, these cost allocation scenario results were also used by the Planning Committee to test the robustness of the RTP.

Projects Eligible for Cost Allocation

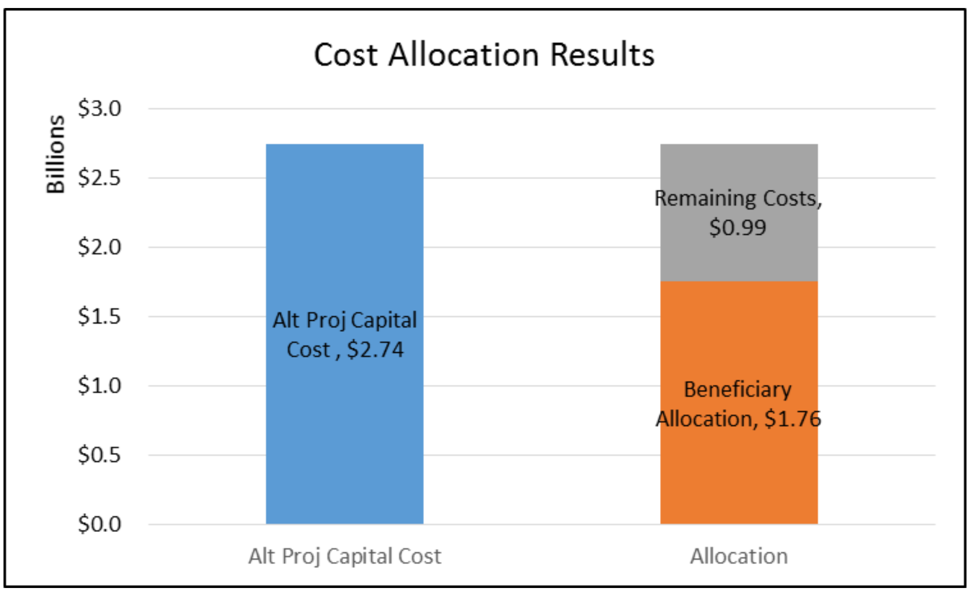
The Alternative Project that was selected into the Draft Final RTP satisfied the criteria to be eligible for cost allocation. This Alternative Project comprised the following transmission facilities:

- A 230-kV line from Windstar to Aeolus in central Wyoming and reinforcements to existing underlying transmission facilities.
- A 500-kV line from Aeolus to Clover near Mona, Utah
- A 500-kV line from Aeolus to Anticline (Bridger) to Populus
- A 345-kV line from Anticline to Bridger

Cost Allocation Results

The Cost Allocation Committee initially identifies Beneficiaries as entities that may be affected by a project based on application of the analysis criteria and cost allocation scenarios. For projects eligible to receive a cost allocation, the Cost Allocation Committee starts with the benefit and Beneficiary calculations provided by the Planning Committee (shown above) and removes those entities that do not receive a benefit from the project being evaluated.

Next, the Cost Allocation Committee adjusts the calculated initial benefits for each Beneficiary based on the Attachment K methodology and criteria. The adjusted net benefits as defined by the Attachment K methodology are used for allocating project costs proportionally to Beneficiaries, but the cost allocation methodology has a benefits-cost threshold test that may result in some costs not being allocated to beneficiaries (e.g., remaining costs). These remaining costs are reallocated among the remaining Beneficiaries, if possible. Reallocation continues among regional Beneficiaries until either all remaining costs are allocated or there are no Beneficiaries above the benefit-cost threshold outlined in the Attachment K. The applicant (i.e., a project sponsor or stakeholder that submits an unsponsored project) may voluntarily accept any remaining project costs. Otherwise, if the thresholds prevent all costs from being reallocated among Beneficiaries and the remaining costs are not accepted by the applicant, the project is no longer eligible for cost allocation.



The cost allocation analysis for the unsponsored Alternative Project resulted in no cost allocation of the Alternative Project. Since the Alternative Project was identified by the Planning Committee during the development of the RTP, there was no Applicant to accept the remaining costs of the project. As a result, since all project costs could not be allocated to Beneficiaries, the Alternative Project was ineligible for cost allocation.

NTTG 2014-2015 Regional Transmission Plan Supporting Materials

The supporting materials referenced in this report have been posted on the NTTG website and can be found using the following link:

> http://www.nttg.biz/site/index.php?option=com_docman&view=list&slug=appendices&Itemid=31.

A list and link to each of the individual supporting documents is also provided below:

1. NTTG 2014-2015 Draft Final Regional Transmission Plan 06-30-2015
2. Revised NTTG Biennial Study Plan Approved 3-9-2015
3. Quarter 5 Additional Study Report - Evaluating Transmission Segments Similar to Energy Gateway
4. NTTG Study Plan for the 2014-2015 Public Policy Consideration Scenario - Final 02-11-15
5. NTTG Report for the 2014-2015 Public Policy Consideration Scenario – Final 05-03-15
6. NTTG Revised Cost Allocation Study Plan Approved 06-03-15
7. Cost Allocation Calculation Workbook Final 06-29-2015