NTTG 2014-2015 DRAFT FINAL REGIONAL TRANSMISSION PLAN

June 30, 2015

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I. Executive Summary

During the first year of the Northern Tier Transmission Group ("NTTG") 2014-2015 Biennial Planning Cycle, the Technical Work Group[1] ("TWG") of the NTTG Planning Committee evaluated the Initial Regional Plan ("IRP") and several Change Case plans to determine the most efficient or cost-effective plan which became the Draft Regional Transmission Plan ("Draft RTP" see Appendix A). Two non-committed projects submitted in Quarter 1 were not included in this Draft RTP; 1) the Boardman to Hemingway (B2H) project, and 2) the Energy Gateway (EG) project. The former was not included because the reliability studies demonstrated it was not needed to meet the performance criteria for all contingencies. The latter was not included because the studies demonstrated that a new unsponsored project, a 500 kV project from Aeolus to Anticline to Populus was a more efficient or cost-effective Alternative Project that reliably met the requirements for the loads and resources represented in the five power flow cases considered.

The Draft RTP report concluded, however, that there were two important lessons learned with the study work done in the first four quarters. First, the power flow studies were based on load and resource data from the TEPPC 2024 production cost model ("PCM") case, which was considered to be the latest information and would provide adequate stress to the NTTG footprint. Study results demonstrated that this was not the case, and the TWG also learned that the TEPPC 2024 case did not have the most recent loads and resources that were submitted in Quarter 1 to NTTG, particularly in the PacifiCorp areas.

Secondly, it was found that the 2014-2015 NTTG Biennial Study Plan created in Quarter 2 was lacking any consideration of contractual commitments, resource integration, transmission service requests (TSRs), and additional transmission capacity considerations. Consequently, the 2014-2015 Biennial Study Plan was revised in Quarter 5 to correct these shortfalls[2]. The revised study plan allows for additional studies to be run using any updates from data submitted in Quarters 1 or 5. It also allows entities to submit transmission service obligations and provides for a transmission needs analysis to be done to compare the transmission requirements listed above with the available transfer capability (ATC). These additional activities were completed in Quarter 6.

Because the TWG was made aware of the inconsistency between the submitted load and resource data to NTTG as compared to the TEPPC 2024 forecast present in the NTTG base cases in Quarter 4, work was initiated in January 2015 to perform additional studies with the higher Quarter 1 loads and additional wind resources in Wyoming. The load forecasts submitted in

[1] This work group was established by the NTTG Planning Committee to create the study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan. The TWG is comprised of NTTG's Funding Transmission Providers 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.

[2] The Revised NTTG Biennial Study Plan was approved March 9, 2015 and is included as Appendix B.

Quarter 5 were the same as those in Quarter 1. The Quarter 5 submittals also included updates to the Boardman to Hemingway ("B2H") project timeline and cost, updated transmission service requirements for Idaho Power Company ("IPC") and Bonneville Power Administration ("BPA"), and new resources in Idaho consisting of a new 540 MW nuclear plant and several renewable resources totaling 451 MW in Idaho. Because the new resources were not submitted until later in Quarter 5, the TWG determined that comprehensive study work with these new resources could not be accomplished in time to meet the due date of the Draft Final Regional Transmission Plan ("DFRTP"). Therefore, only a high level study was performed with these resources using the updated summer study case to inform the development of the RTP in the 2016-2017 Biennial Planning Cycle. The updated transmission service data for IPC and BPA were implemented in the new transmission needs analysis conducted in Quarter 6.

Results of the additional studies performed in Quarters 5 and 6 demonstrated that with the higher PacifiCorp loads in Utah, Wyoming and Idaho, and with additional wind resources in Wyoming to meet those loads, the Change Case with the Alternative Project identified in the Draft RTP (Aeolus to Anticline to Populus 500 kV line) was not adequate to meet the system performance criteria. Studies conducted by the TWG demonstrated that a new Change Case with a different Alternative Project, consisting of a new 230 kV line and upgrades to existing underlying transmission from Windstar substation to Aeolus substation in Wyoming, a new 345 kV line from Anticline to Bridger (Wyoming), and a new 500 kV transmission line from Aeolus to Mona, Utah (Clover substation), were needed in addition to the Aeolus to Anticline to Populus 500 kV line identified in the Draft RTP. The transmission needs and capability analysis demonstrated that the Boardman to Hemingway 500 kV project is also required in order to meet Idaho Power's transmission needs.

In addition to the reliability studies and the transmission needs analysis, the TWG also created cost allocation scenario cases that represent four different future conditions with different loads and generation dispatch. These cases were helpful in testing the robustness of the DFRTP and were also used to provide economic data for the cost allocation calculations where comparisons were made between the Initial Regional Plan ("IRP") and the DFRTP and each of the Cost Allocation scenario cases.

II. Introduction

The Northern Tier Transmission Group 2014-2015 DFRTP was developed in accordance with the NTTG's Transmission Providers' Attachment K that included FERC Order 1000 regional transmission planning requirements[3]. The DFRTP is a result of reliability and economic studies and activities outlined in the Revised NTTG Biennial Study Plan for the 2014-15 Regional

[3] FERC issued order 145 FERC 61,060 on Oct. 17, 2013 that partially approved the Funding Transmission Providers FERC Order 1000 Regional Planning compliance filings and instructed the NTTG Funding TPs to proceed implementation of the TP's regional compliance filings on October 1, 2013 subject to prospective adjustments should FERC's final order require such adjustments.

Planning Cycle[4] and carried out by the NTTG TWG. This report is divided into two major sections -- the Planning process and the Cost Allocation process. The Planning process began with development of the Initial Regional Plan ("IRP") using a bottom-up approach by aggregating the NTTG Transmission Providers' local transmission plans into a single regional transmission plan. Next, the IRP non-committed projects within the NTTG geographical area were analyzed by creating Change Case plans to determine whether there were Alternative Projects that would yield a regional transmission plan that would be more efficient or cost effective than the IRP that meets the regional needs. It is the result of this analysis that formulated the DFRTP presented herein. The report focuses on the activities completed by the TWG during Quarters 5 and 6 of the 2014-2015 biennial planning cycle. The activities of Quarters 1 through 4 that resulted in the Draft RTP[5] were also important in defining what additional work was needed in Quarters 5 and 6 to produce the DFRTP.

During Quarters 5 and 6, the TWG focused on the following activities: 1) a revised biennial study plan; 2) additional power flow studies with updated loads and resources for PacifiCorp in order to determine the most efficient or cost-effective plan under these new conditions that would be included in the DFRTP; 3) the Public Policy Consideration ("PPC") studies; 4) transmission needs and available transfer capability ("ATC"); 5) a high-level power flow study of the new Quarter 5 resources using one load/generation dispatch condition; 6) robustness analysis of the DFRTP Change Case, and 7) the Planning Committee's support of the cost allocation processes which includes the creation of cost allocation scenario base cases and subsequent power flow analysis, determination of the economic metrics from the scenario cases for use in the cost allocation analysis, and working with the Cost Allocation Committee in determining benefits and Beneficiaries for cost allocation.

III. Revised Biennial Study Plan

Because of "lessons learned" in the first four Quarters of the 2014-2015 biennial planning cycle and development of the Draft RTP, the NTTG 2014-2015 Biennial Study Plan developed in Quarter 2 was revised to "accommodate data updated during Quarter 5, additional reliability studies (based on the updated data), and to address transmission service obligations." The revised 2014-2015 Biennial Study Plan was approved by the NTTG Steering Committee on March 9, 2015 (see Biennial Study Plans in Appendix B). The TWG used this revised study plan to carry out the activities in Quarter 5 and 6. The cost allocation section of the Revised Study Plan (section C.2) was later augmented with a separate Revised Cost Allocation Study Plan that was approved June 3, 2015 by the Planning and Cost Allocation Committees (see Appendix I).

[4] Appendix B - Revised NTTG Biennial Study Plan Approved 3-9-2015

[5] See the Draft RTP document in Appendix A

IV. Planning Process

A. Study Methodology

To determine the most efficient or cost-effective transmission plan that would become the DFRTP, both reliability and economic studies were performed in accordance with the Revised 2014-2015 Biennial Study Plan. The reliability studies utilized power flow cases from Quarters 1 to 4 updated with loads and resources submitted in Quarters 1 and 5. The economic studies examined the providers' Attachment K's three metrics--capital-related costs, energy losses, and reserves to determine the transmission plan cost effectiveness. Economic metrics were also derived from the Quarter 5 and 6 power flow studies for use in the Cost Allocation process.

B. Quarter Five Data Submittals

New data submittals were made by PacifiCorp, IPC, BPA, and Utah Associated Municipal Power Systems ("UAMPS") in Quarter 5. PacifiCorp removed all future transmission service obligations. IPC modified the in-service date and cost of B2H, added 451 MW of renewable resources in Idaho, and updated their transmission service obligations with the Northwest. BPA also submitted transmission service obligations with Idaho. UAMPS submitted a new 540 MW nuclear generating plant in eastern Idaho. The transmission service obligation changes were included in the transmission needs section of the planning process and the revised costs were used in the cost allocation process. The new resource information was used in separate high-level power flow studies intended to inform next cycle's Regional Transmission Plan.

C. Additional Studies in Quarters Five and Six

The revised Biennial Study Plan allows for performing studies with updated information submitted during Quarter 1 and/or Quarter 5 of the biennial cycle. In January 2015, the TWG determined that the summer, winter, and export cases created in Quarters 1 through 4 with 2024 TEPPC loads and resources should be updated to reflect the Quarter 1 submitted loads and resources in the PacifiCorp East (PACE) area, including additional wind generation in Wyoming. Both IRP cases and the Draft RTP cases were updated with the Quarter 1 loads and resources.

All of the cases were studied with the updated loads and resources to determine if the identified Alternative Project would still meet the reliability requirements required of the Initial Regional Plan. The revised studies identified several significant N-0 and N-1 performance violations due to the revised load and resources (see Table 1 below)[6].

[6] See the complete report "NTTG Biennial Studies - Quarter 5 Additional Studies Evaluating Transmission Segments Similar to Energy Gateway" in Appendix C. The IRTP studies are designated as "segment 0" cases and the Draft RTP updated cases are labeled as "Draft RTP with Q5 L & R".

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

Table 1 - Overall violations of the Draft RTP Cases with Q5 loads and resources

Additional studies were conducted to determine what additional transmission was needed to provide adequate reliability performance. The results of this process determined the original Alternative Project needed to be revised and the new Alternative Project would need to have the following transmission projects added:

1. A 230 kV line from Windstar to Aeolus in central Wyoming and reinforcements to existing underlying transmission facilities.
2. A 500 kV line from Aeolus to Clover near Mona, Utah
3. A 500 kV line from Aeolus to Anticline (Bridger) to Populus (selected into the Draft RTP)
4. A 345 kV line from Anticline to Bridger

This new Quarter 6 Alternative Project is proposed by the TWG as an unsponsored project. The change case with this new Alternative Project resulted in higher NTTG losses, but is more cost-effective because of a lower capital cost (see the Cost Allocation Process Section of the report). In the Additional Studies report (see Appendix C) the Change Cases with this new Alternative Project are referred to as the "segment 2" cases.

D. Transmission Needs and Available Capacity Analysis

With the Draft RTP in Quarter 4, NTTG recognized the need to revise the Biennial Study Plan to include an analysis of transmission needs and obligations compared with the available transfer capabilities ("ATCs"). In Quarter 5 IPC and BPA submitted transmission service obligations ("TSOs"). PacifiCorp removed in Quarter 5 all of its future TSOs that had been submitted in Quarter 1. Table 4 lists the remaining NTTG TSOs to be evaluated.

Submitted By	POR	POD	Start Date	End Date	Transmission Obligation (MW)	WECC Path Number/ Direction
Idaho Power	Northwest	IPCO	1/1/2021	-	500 (summer) 200 (winter)	14 W-E
						82 W-E
BPA	Northwest	BPA SEID	1/1/2020	12/31/2028	250 (summer) 550 (winter)	14 W-E
						82 W-E
						17 W-E

Table 4 - Transmission Service Obligations submitted in Quarter 5

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Table 5 below shows the existing Total Transfer Capabilities ("TTCs") and ATCs for the critical paths between Idaho and the Northwest. The fourth column is the difference of the TTCs and the ATCs which demonstrates the transmission capacity being utilized in the year 2014. The TSOs from Table 4 are listed in column five. The last column is the sum of columns four and five which indicates the total amount of transmission capacity that is needed in 2024 to fulfill all of the transmission requirements for that path.

WECC Path Number/ Direction	2014 TTC (MW)	2014 ATC (MW)	2014 Transmission Capacity Utilized (MW)	Transmission Obligation Change Between 2014 and 2024 (MW)	2024 Transmission Capacity Needed (MW)
14 W-E (ID-NW)	1200	0	1200	750	**1950**
82 W-E (TOTBEAST)	2465	150	2315	750	**3065**
17 W-E (Borah W)	1600	1445	155	550	**705**

Table 5 - Transmission Capacity Needed in the year 2024

Table 6 is a comparison of the 2024 transmission capacity needed ("TCN") from Table 5 with expected 2024 TTCs of the critical paths for the three plans that were considered during the 2014-2015 Biennial Planning Cycle. The TTCs for these future projects are based on WECC Path Rating Studies performed for the B2H project. Numbers in red indicate a deficiency in meeting the transmission needs on the path. Green numbers are those which have sufficient capacity to meet the transmission needs.

WECC Path Number/ Direction	2024 Transmission Capacity Needed (MW)	2024 TTC for each Proposed Topology (MW)		
		2024 TTC IRTP (w/ B2H)	2024 TTC Draft RTP (w/o B2H)	2024 TTC DFRTP (w/ B2H)
14 W-E (ID-NW)	**1950**	2250	1200	2250
82 W-E (TOTBEAST)	**3065**	3515	2465	3515
17 W-E (Borah W)	**705**	1600	1600	1600

Table 6 - Comparison of 2024 Transmission Needs with Expected TTC for various RTPs. Red is unacceptable, green is acceptable

The results of this comparison clearly demonstrates the need for the B2H project in the DFRTP to satisfy the transmission needs of IPC and BPA.

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E. Public Policy Consideration Study

The Transmission Providers' Attachment K's state that Public Policy Consideration ("PPC") studies are to be submitted during Quarter 2 of the Biennial Cycle. It also asserts that the PPC studies are only to "inform" the RTP but not be used to define the plan. During Quarter 2 of the 2014-2015 biennial cycle, a PPC study was identified. This study followed the PPC study plan[7] that assumed that the Colstrip units 1 and 2 would be retired and replaced with an equal amount of wind generating capacity (610 MW) at the Broadview substation. The steady state study analyzed the impacts to the transmission system. It was assumed that the wind at Broadview would have a similar trip response as the acceleration trend relay that protects the Colstrip units. The results of the study showed no reduction in transfer capability when replacing the coal units with wind generation as long as the wind responded similarly to the Colstrip units for outages on the 500 kV transmission system. Although this study produced some interesting information, it did not influence the selection of transmission facilities for the DFRTP. The complete report for this study was approved on May 13, 2015 by NTTG and is included as Appendix E of this report.

F. Projects Selected into the DFRTP

As described in sections IV.C and IV.D above on Additional Studies in Quarters 5 and 6 and Transmission Needs and Available Capacity Analysis, several transmission facilities were selected by the TWG to be included in the DFRTP. Based on reliability considerations, the unsponsored project includes:

1. A 230 kV line from Windstar to Aeolus in central Wyoming and reinforcements to existing underlying transmission facilities.
2. A 500 kV line from Aeolus to Clover near Mona, Utah
3. A 500 kV line from Aeolus to Anticline (Bridger) to Populus (selected into the Draft RTP)
4. A 345 kV line from Anticline to Bridger

Based on the transmission needs analysis, the following Sponsored Project is also included:

The B2H 500 kV project

As the unsponsored project identified in the regional planning process was selected into the DFRTP, and has an estimated cost exceeding $20 million, it qualifies for cost allocation consideration according to the Attachment K's. Cost allocation was not requested for the B2H Sponsored Project.

[7] See the approved PPC study plan in Appendix D

G. Robustness Analysis

Since TWG performed studies with the new Alternative Project for Summer, Winter, and Export cases (with the updated loads and resources)[8], the DFRTP without B2H was proven to meet the performance criteria for at least three different future conditions with different load levels and resource dispatch. In addition to these studies, the B2H project was added to the summer case to form a complete DFRTP summer case. From this case, four cost allocation scenarios were created and studies were performed (see the Cost Allocation section of the report). Two of these scenarios varied the load in the NTTG footprint by +/- 1000 MW. The two other cases looked at different system conditions displacing wind or coal generation with other renewable resources. The results of these studies demonstrate no changes in transmission were needed for these additional scenarios. For more details about the cost allocation scenario results, see the Cost Allocation section of the report. All of these additional studies demonstrate the robustness of the DFRTP.

H. New Quarter 5 Resource Studies

NTTG received two data submittals in Quarter 5 for some new resources in Idaho. The first was submitted by UAMPS for a 540 MW nuclear generating plant near the Scoville substation. The second included a number of solar plants and a few small hydro plants scattered throughout Idaho totaling 451 MW. These submittals were received in late February or early March of 2015. The TWG considered the timeline to produce the DFRTP and decided to perform high-level sensitivity studies on the DFRTP summer case. A separate study was performed for each of the two resource submittals (see the complete reports in Appendix F & G - New Resource Studies).

<u>UAMPS 540 MW nuclear generating plant</u> - In this study the new 540 MW nuclear generating plant was connected at the Antelope 230 kV bus in the power flow since specific interconnection designs were not submitted. Other UAMPS resources were reduced in Utah to balance the power flow. Results of the N-0 study demonstrates that there were two overloaded facilities near the location of the new generation; 1) the Antelope-Goshen 161 kV line and 2) the Antelope 230/161 kV transformer. The contingency studies demonstrated 13 overloads of the same two elements. Although this study represents only one specific system condition, it points out a need for detailed interconnection studies with the applicable transmission provider in order to fully define the impacts to the system. The project owners should comply with the transmission provider's procedures for generation and transmission interconnection studies. See Appendix F for full study details and results.

<u>451 MW of new solar and hydro plants in Idaho</u> - In this study the new renewable resources were modeled at four different locations within the Idaho Power system according to the submittal description. Other Idaho hydro resources were reduced in order to maintain the same Idaho area interchange as that of the DFRTP case. Results of this study demonstrated no

[8] These are the "segment 2" cases in the Q5 Additional Studies report in Appendix C

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performance violations of any concern. However, this study represents only one set of system conditions. The project owners should comply with the transmission provider's procedures for generation and transmission interconnection studies. Details of this study are also in Appendix G.

V. Cost Allocation Process

The Cost Allocation Committee ("CAC"), which is governed by the CAC Charter, is charged with the task of allocating costs to Beneficiaries of transmission projects selected into the Regional Transmission Plan for cost allocation purposes in accordance with the Transmission Provider's Attachment K obligations. NTTG's cost allocation process is conducted by the CAC.

As described in Attachment K, the cost allocation process will be applied to a transmission project (sponsored or unsponsored) that has an estimated cost exceeding $20 million and is selected in the Regional Transmission Plan for purposes of cost allocation. There are three categories of regional transmission projects that may be eligible for cost allocation: a sponsored project that meets certain pre-qualification criterion, an unsponsored project that is identified in the planning process, and an unsponsored project proposed by a non-sponsor.

During NTTG's 2014-2015 biennial planning cycle there were two transmission projects considered for selection into the Draft Regional Transmission Plan ("DRTP") for regional cost allocation and one transmission project not requesting cost allocation. The first project requesting cost allocation was a Sponsored Project submitted by LS Power for its SWIP-North transmission project. The biennial planning process did not select[9] this sponsored project into the Draft Final Regional Transmission Plan ("DFRTP") for purposes of cost allocation as the reliability and economic analysis results indicated that it was not the most cost effective or efficient solution to meet the needs. The second project requesting cost allocation was an unsponsored project that was identified in the planning process and pursuant to the Attachment K requirements, it was selected into the DFRTP for purposes of regional cost allocation. This unsponsored project, named Alternative Project, is an east to west transmission project that starts in eastern Wyoming and ends in eastern Idaho. The transmission project not requesting costs allocation, the sponsored Energy Gateway Project, was not selected into the DFRTP.

As described in the Planning Committee section G above, the Alternative Project that was selected into the DFRTP is comprised of the following transmission facilities:

- Windstar to Aeolus 230 kV;
- Reinforcements to underlying transmission system in Wyoming;
- Aeolus to Clover 500 kV;
- Aeolus to Anticline to Populus 500 kV; and
- Anticline to Bridger, 345 kV.

[9] See NTTG 2014-2015 Draft Regional Transmission Plan – 02-11-2015 for additional information.

The Alternative Project eligible for cost allocation and incorporated in the DRTP underwent cost allocation by the CAC as described in the following sections.

A. Cost Allocation Scenarios

Pursuant to Attachment K, the CAC, in consultation with the Planning Committee and with stakeholder input, creates cost allocation scenarios ("Allocation Scenarios") for those parameters that likely affect the amount of total benefits of a project and the distribution of the benefits to Beneficiaries. These Allocation Scenarios became part of the Biennial Study Plan during its development in Quarter 2. Per Attachment K, Allocation Scenarios are not to be used by the Planning Committee and the CAC until the development of, and the allocation of, costs pursuant to those benefits to Beneficiaries starting in Quarter 6. As described in the Attachment K, the variables in the Allocation Scenarios will include, but are not limited to, load levels by Load Serving Entity ("LSE") and geographic location within Balancing Authority Areas, fuel prices, and fuel and resource availability. This process will provide the overall range of future Allocation Scenarios that will be used in determining a project's benefits and Beneficiaries.

During Quarter 2 and after the Planning Committee evaluated the projects, the CAC, as defined in the Biennial Study Plan, evaluated the Allocation Scenarios. The Biennial Study Plan states that the 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 CAC 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 cost allocation metric. The selected alternative Allocation 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 affects the distribution of benefits for that metric among Transmission Providers, LSEs, and/or independent power producers. 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

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In Quarter 4 the CAC developed the following Allocation Scenarios that adhere to the Quarter 2 Biennial Study Plan. The CAC reviewed and discussed the Allocation Scenarios at the December 18, 2014 NTTG stakeholder meeting. A summary of the resulting Cost Allocation Scenarios Discussion Paper provided in the Appendix H is provided as follows:

High and Low Load Forecasts

Two Allocation Scenarios were developed by adding and subtracting 1,000 MW of load in the NTTG footprint. These two Allocation Scenarios were developed by adjusting 2024 power-flow base case load data by Balancing Authority Area ("BAA") by plus or minus 1,000 MW. The load adjustments by BAA were prorated using weighting factors calculated from the actual 2012 and 2013 peak demand and from the projected 2024 peak demand by BAA. The following table displays the result of this calculation.

2024 PCM Data				2012 Actual + 2013 Actual + 2024 PCM Weights		
	MW					
	Actual 2012	Actual 2013	PCM 2024	Weight	Low Scn -1000	High Scn 1000
IPC	3,587	3,407	4,013	16.7%	3,846	4,180
NWE	1,785	1,707	1,855	8.1%	1,774	1,936
PACE	6,763	8,989	9,798	38.7%	9,411	10,185
PACW	3,708	4,354	4,083	18.4%	3,899	4,267
PGE	3,642	3,900	4,426	18.1%	4,245	4,607
NTTG	19,485	22,357	24,175	100.0%	23,175	25,175

Replace Wind with Solar Generation

This allocation scenario assumed that 800 MW of wind from the high wind penetration areas is replaced with solar in potential high penetration solar areas. The following table displays the result of this calculation.

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Replace 800 MW Wind with 800 MW Solar

	Wind Reduction of Nameplate MW				Solar Addition to Nameplate			
	MW	Area To Use	MW -800	Pro Rated MW	MW	Area To Use	MW 800	Pro Rated MW
IPFE	80		0	80	0	1.00	200	200
IPMV	228	1.00	-54	174	0	1.00	200	200
IPTV	368	1.00	-87	281	0	1.00	200	200
NWMT	632	1.00	-149	483	0		0	0
PACW	626	1.00	-147	478	0		0	0
PAID	212	1.00	-50	162	0		0	0
PAUT	0		0	0	460	1.00	200	660
PAWY	1,329	1.00	-313	1,015	0		0	0
PGE	0		0	0	2		0	2
Total	3,474		-800	2,674	462		800	1,262

Replace 1,000 MW of Coal with an Equivalent Annual Energy Output from Wind and Solar

The next allocation scenario presumes 1,000 MW of coal units that are not retired in the 2024 case can be reduced pro rata and replaced with an equivalent amount of equal shares of wind and solar in the appropriate geographic locations (e.g. wind in WY and MT and solar in ID and UT). The following table shows the original 2024 PCM MW data for coal, solar and wind in columns b through column d. This table also shows the MW adjustment necessary to reduce coal by 1,000 MW in column e and to increase the wind and solar MW in columns f and g to compensate for the energy that was lost as a result of the coal reduction.

2024 PCM Data

Nameplate MW

				Recommended Adjustments					
	b	c	d	e	f	g	h	i	j
	2024 PCM Data			Coal	Solar *	Wind *	ADJUSTED MW		
	Coal **	Solar	Wind	-1,000	1,656	1,117	Coal	Solar *	Wind *
IPFE	0	0	80	0	414	0	0	414	80
IPMV	0	0	228	0	414	0	0	414	228
IPTV	0	0	368	0	414	0	0	414	368
NWMT	2,658	0	632	-234	0	146	2,423	0	778
PACW	0	0	626	0	0	485	0	0	1,111
PAID	0	0	212	0	0	0	0	0	212
PAUT	4,801	460	0	-424	414	0	4,378	874	0
PAWY	3,877	0	1,329	-342	0	485	3,535	0	1,814
PGE		2	0	0	0	0	0	2	0
Total	11,336	462	3,474	-1,000	1,656	1,117	10,336	2,118	4,591

* Adjusts solar and wind MW to makeup for energy lost from coal reduction

** Accounts for coal retirements.

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B. Cost Allocation Study Plan

In Quarter 6 NTTG's Technical Work Group revised the Quarter 2 Biennial Study Plan to lay out the process whereby the NTTG Technical Work Group will use the DFRTP to develop and analyze Allocation Scenarios. This analysis will determine the benefits of the Alternative Project selected in the DFRTP for purposes of cost allocation. After receiving information performed by the Technical Work Group, a Cost Allocation Study Plan that describes the methodology that the CAC will use in the cost allocation process was revised and subsequently approved by both the Cost Allocation and Planning Committees. See Appendix I, the Revised Cost Allocation Study Plan.

The Revised Cost Allocation Study Plan charged the Technical Work Group to use the DFRTP as the basis for creating the four Allocation Scenarios. These scenarios will each be derived from the modified version of the 2024 summer peak data that was used to model the two non-committed projects that were selected into the DFRTP. The following describes the four Allocation Scenarios approved by the CAC:

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

Scenario D: Take out 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 and solar in the appropriate geographic locations (e.g. wind in WY and MT and solar in ID and UT).

The Technical Work Group used power flow analysis to analyze the DFRTP and the Initial Regional Plan (IRP) adjusted for updated Quarter 5 loads and resources (i.e., referred to as the Change Case in the revised study plan), and the four Allocation Scenarios. This analysis included the N-0 power flow study to create a solved N-0 case 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.

Next the Technical Work Group followed the Cost Allocation Study Plan and used the results from the power flow analysis to define three metrics - capital cost benefit, line loss benefit and reserve margin benefit. These metrics are used in the benefits and Beneficiary analysis. Each metric will be expressed as an annual change in costs (or revenue). A common year was selected for net present value calculations for all cases to enable a comparative analysis

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between each DFRTP, the four Allocation Scenarios, and the IRP, as adjusted for updated Quarter 5 load and resource data. Additional details on the development and use of the Allocation Scenario Base Cases follows.

C. Cost Allocation Scenario Base Cases

The approved Revised Cost Allocation Study Plan[10] requires that the TWG provide power flow base cases for four specific Allocation Scenarios listed in the study plan. TWG created Scenarios A through D, described above, from 1) the Change Case representing the Draft Final Regional Transmission Plan (DFRTP); and 2) from the Initial Regional Plan (IRP) which had been adjusted for the updated loads and resources in Quarter 5. The same dispatch changes were made for the DFRTP and the IRP so that a true comparison could be made in determining the most efficient or cost-effective plan. The Allocation Scenario cases are described below and in more detail in Appendix H

1. Scenario A - Increase the NTTG load by 1000 MW: For this case, TWG followed the tables in Appendix A of the study plan where the load in the following areas of the base case were increased by the amount shown - Idaho Power 167 MW, NorthWestern Energy 81 MW, PACE 387 MW, PACW 184 MW, and Portland General 181 MW. The area load in each of these areas was scaled to achieve the desired amount. The generation was made up within the Northwest area for the PACW and PGE owners, and within the area boundaries for the other areas.
2. Scenario B - Decrease the NTTG load by 1000 MW: In this scenario the base case area loads were decreased by the same amounts shown in Scenario A according to the tables in Appendix B of the study plan. The generation within each area was scaled down to match the load reduction.
3. Scenario C - Replace 800 MW of wind generation capacity with solar generation capacity within the NTTG footprint: Wind generation was reduced according to the amounts shown in the table in Appendix B of the study plan - IPC 141 MW, NWE 149 MW, PACW 147 MW, and PACE 363 MW. Additionally, 600 MW of solar generation was added in Idaho and 200 MW in Utah. Figure 1 below is an illustration of the approximate re-dispatch of generation within NTTG.

[10] See the Revised Cost Allocation Study Plan in Appendix I

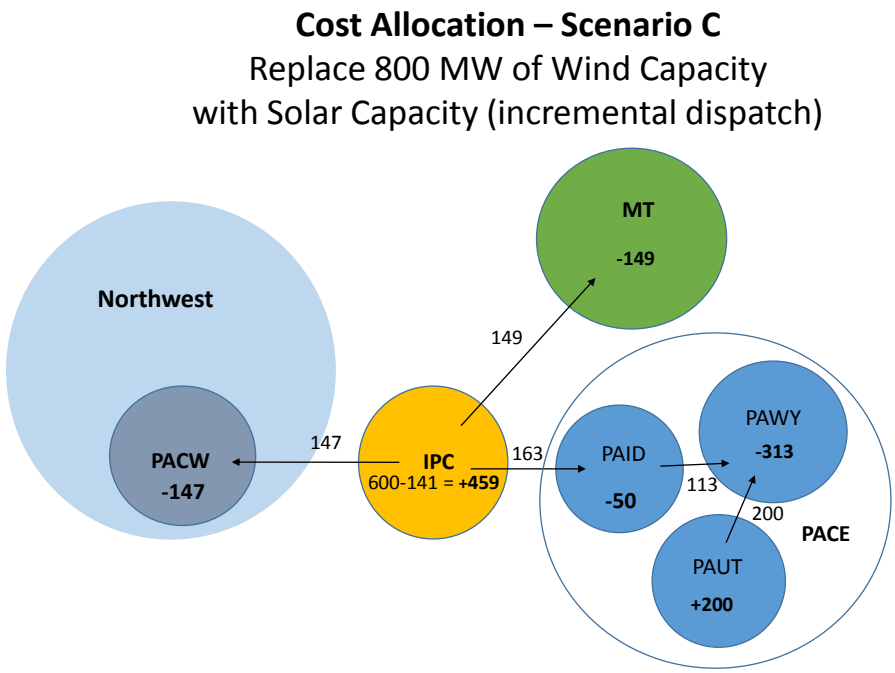

Figure 1 - Cost Allocation Scenario C re-dispatch illustration

4. Scenario D - Replace 1000 MW of coal generation energy with wind and solar generation energy: Once again the amount of generation reduced and replaced was specified in the Appendix B tables of the Cost Allocation Study Plan. Coal generation was reduced by 424 MW in Utah, 342 MW in Wyoming, and 234 MW in Montana. Wind generation was increased by 485 MW in PACW, 485 MW in Wyoming, and 146 MW in Montana. Solar generation was increased by 414 MW in Utah and 1242 MW in Idaho. As described in the Scenario D description from the Cost Allocation Committee, Scenario D was to take into account the provided capacity factors in order to achieve a balance in energy. Consequently, there was an increase of 1116 MW of wind generation and 1656 MW of solar generation, and a reduction of 1000 MW of coal generation within NTTG in the power flow base case. With these changes, NTTG ended up with a surplus of 1772 MW of generation. In order to achieve a balanced power flow case, this surplus generation was scheduled to Grand Coulee dam in the Northwest area. A diagram of the approximate re-dispatch is shown in Figure 2 below.

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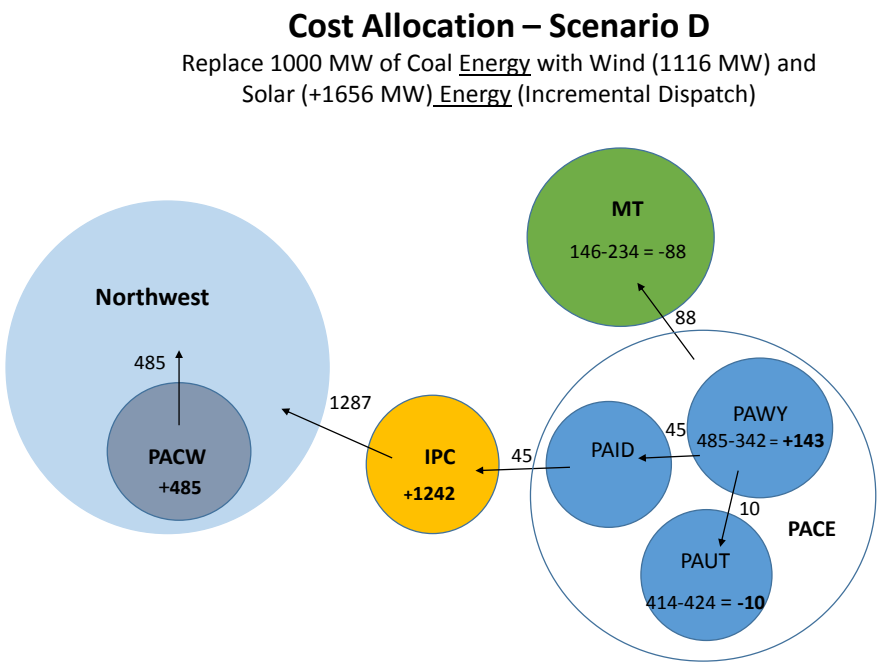

Figure 2 - Cost Allocation Scenario D incremental dispatch illustration

D. Power Flow Results of the Cost Allocation Scenario Cases

The IRP power flow Allocation Scenario cases A through D were created and solved, and the losses noted for each of the areas for the economic metric analysis. The DFRTP power flow Allocation Scenario cases A through D were also solved and contingencies performed. The losses for these cases were also derived for the economic analysis. The results of each of the DFRTP scenario cases are described below.

1. Scenario A - Increase the NTTG load by 1000 MW: Results of this analysis demonstrated no significant violations other than lower voltage buses even with the load addition. Therefore there is no need for any additional capital costs. The overall NTTG losses in this case increased slightly (14.4 MW) over the IRP scenario case. Idaho Power had the largest increase with 7.4 MW. PACE and NWE each had an increase in losses of about 3 MW. There were no reserve benefits for this scenario.
2. Scenario B - Decrease the NTTG load by 1000 MW: Results of this study also demonstrated no significant violations except for some lower voltage buses. The overall NTTG losses increased by 10.5 MW over the IRP scenario case. Idaho Power again had the largest increase in losses with 5.1 MW, followed by NWE and PACE with 2 MW each. There were no reserve benefits for this scenario. In order to determine if less transmission was needed with the reduction in load, a case was performed without the Aeolus-Clover 500 kV line. The results for this case were unacceptable. Thus the capital costs for this scenario would not change.

3. Scenario C - Replace 800 MW of wind generation capacity with solar generation capacity within the NTTG footprint: The results of this case demonstrated no significant performance violations with the exceptions of lower voltage buses. No capital additions were required. The total NTTG losses went up by 7.2 MW, with Idaho Power having the largest increase of 3.2 MW followed by NWE with 1.8, PACE with 1.5 MW, and PACW with 1.1 MW. No reserve benefits were noted for this scenario either.
4. Scenario D - Replace 1000 MW of coal generation energy with wind and solar generation energy: Results for this case demonstrated no significant performance violations except for some lower voltage buses. Therefore, no additional capital costs are required. The total NTTG losses increased by 1.1 MW. As with the other scenarios there were no reserve benefits for this scenario.

All of the loss results for the Allocation Scenario Cases were summarized, annualized and monetized in a spreadsheet for use as inputs to the Cost Allocation Templates for determining cost allocations. This spreadsheet is provided as workbook tabs in Appendix J

E. Cost Allocation Analysis and Results

To facilitate the analysis of the data provided by the Planning Committee for purposes of cost allocation, the CAC developed a cost allocation template reflecting the required components of the cost allocation methodology specified in Attachment K. This template was developed as an Excel workbook and is included as Appendix J.

The cost allocation template includes two worksheets. The first worksheet, titled "Planning", uses data from the three metrics (i.e., capital cost and capital related cost data and the monetized line loss and reserve data) to develop the benefit associated with the Alternative Project. This worksheet also identifies the Beneficiaries provided by the Technical Work Group. The second worksheet, titled "Cost Allocation", applies the Attachment K cost allocation methodology to the Planning worksheet benefit and Beneficiary information to allocate the cost of the Alternative Project to its Beneficiaries. The following sections provide additional explanation of the two worksheets.

Planning Worksheet

The goal of the biennial transmission planning process is to identify a Regional Transmission Plan that is more efficient or cost effective than the IRP. The DFRTP meets this goal because it replaced the IRP non-committed projects with the Quarter 6 non-committed unsponsored Alternative Project. The planning worksheet is divided into the Capital Cost Section, Calculating Benefit and Beneficiary Section, and Initial Benefits and Beneficiaries Section. The following is a brief discussion of each section of the planning worksheet.

Capital Cost Section

The capital costs shown in this worksheet is for the non-committed projects in the IRP and the Quarter 6 non-committed Alternative Project.

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Calculating Benefit and Beneficiaries Section

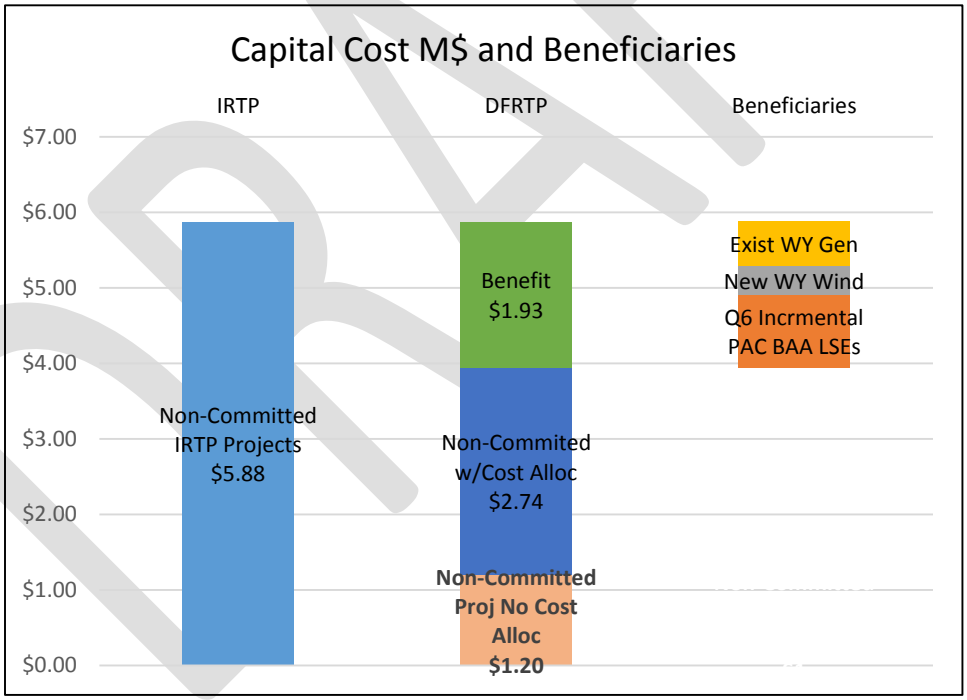
This section calculates the Alternative Project cost to Beneficiaries for the three metrics (capital cost, loss and reserve). Each metric is described below.

Capital Cost Metric

The first calculation is to compute the $1,993,666,954 DFRTP capital cost benefit. This benefit is computed as the capital cost savings between the IRP non-committed capital cost and the DFRTP non-committed projects capital cost.

IRP		DFRTP	
Non-Committed IRP Projects	$5,877,693,948	Non-Committed DFRTP	$3,944,026,994
		Alternative Project	$2,744,026,994

Next the three Beneficiaries were identified for the $1,933,666,953 benefit[11]. These Beneficiaries are shown in the right hand column in the graph below.



The identification of these Beneficiaries were the result of the IRP and DFRTP analysis. The DRTP analyses found that the amount of PacifiCorp BAA LSEs load was understated by 1,800 MW. The PacifiCorp BAA load was corrected in the Quarter 6 DFRTP analysis. Also, to maintain

load and resource balance in the DFRTP analysis, the Technical Work Group dispatched Wyoming generation that was not dispatched in the analysis. This increased dispatched generation included 712 MW[12] of proposed new Wyoming wind and 1,100 MW of existing non-dispatched Wyoming generation.

For purposes of the DFRTP cost allocation, the three Beneficiaries and the MW quantity of their benefits are:

- LSEs within the PacifiCorp BAAs - 1,800 MW;
- New Wyoming wind generation within PACE BAA – 712 MW; and
- Existing Wyoming generation within the PACE BAA – 1,100 MW.

The Alternative Project's benefit of $1,933,666,954 was then allocated to the three Beneficiaries based on their pro rata share of megawatts of benefits.

	DFRTP Allocation		
DFRTP Beneficiaries	MW	Pct	DFRTP Benefit
Q6 Incremental PAC BAA LSEs Load	1,800	49.8%	$963,621,406
Q6 WY Wind (New)	712	19.7%	$381,165,800
Q6 Incremental WY Gen (Existing)	1,100	30.5%	$588,879,748
Q6 Total	3,612	100%	$1,933,666,954

As described above, the four Allocation Scenarios were designed to capture the impacts of varying the peak load (Allocation Scenarios A and B) and resource type and location (scenarios C and D). The table below calculates the allocation scenario A and B adjustment to the PAC BAA LSEs load. The DFRTP 1,800 MW PacifiCorp BAA LSEs load in the above table was adjusted by plus and minus 387.5 MW that is the PAC BAA load share of 1,000 MW adjustment.

[12] The DRTP included only 712 MW of new Wyoming wind generation.

		Q6 Incremental PAC BAA LSEs Load
DFRTP	MW	1,800
	Percent	100%
	Benefit	$963,621,406
CAC Scenario A Change DFRTP MW by 387.5MW	MW	2,188
	Percent	100%
	Benefit	$963,621,406
CAC Scenario B Change DFRTP MW by -387.5MW	MW	1,413
	Percent	100%
	Benefit	$963,621,406
CAC Scenario C	Benefit	$963,621,406
CAC Scenario D	Benefit	$963,621,406

Allocation scenario C replaced wind with solar, and allocation scenario D replaced 1,000 MW coal annual energy output with wind and solar. The table below calculates the Allocation Scenarios C and D adjustment to the new Q6 WY Wind (New) and Q6 Incremental WY Gen (Existing) generation pursuant to the allocation scenario requirements. Note the MW values represent the Wyoming generation share of the amount specified by the allocation scenario. The $970,045,548 total in the right hand column is the sum of Q6 WY Wind (New) and Q6 Incremental WY Gen (Existing) described above.

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		Q6 WY Wind (New)	Q6 Incremental WY Gen (Existing)	Total
DFRTP	MW	712	1,100	1,812
	Percent	39%	61%	100%
	Benefit	$381,165,800	$588,879,748	$970,045,548
CAC Scenario A	Benefit	$381,165,800	$588,879,748	$970,045,548
CAC Scenario B	Benefit	$381,165,800	$588,879,748	$970,045,548
CAC Scenario C	MW	399	1,100	1,499
Change DFRTP MW by -313MW	Percent	27%	73%	100%
	Benefit	$258,204,252	$711,841,296	$970,045,548
CAC Scenario D	MW	1,197	1,100	2,297
Change DFRTP MW by 485MW	Percent	52%	48%	100%
	Benefit	$505,504,798	$464,540,750	$970,045,548

Finally each Beneficiary's benefit was converted to levelized capital related costs by multiplying the capital cost benefit by a 14.4% fixed charge rate[13]. The following table displays the result of calculation.

	Levelized Capital Related Cost Beneficiaries			
	Q6 Incremental PAC BAA LSEs Load	Q6 WY Wind (New)	Q6 Incremental WY Gen (Existing)	Total Benefit
DFRTP	$138,783,318	$54,896,512	$84,812,028	$278,491,858
CAC Scenario A	$138,783,318	$54,896,512	$84,812,028	$278,491,858
CAC Scenario B	$138,783,318	$54,896,512	$84,812,028	$278,491,858
CAC Scenario C	$138,783,318	$37,187,263	$102,521,277	$278,491,858
CAC Scenario D	$138,783,318	$72,804,146	$66,904,394	$278,491,858

[13] The fixed charge rate was computed as the ratio of the levelized total present value for 40 years annual capital related costs divided by the project capital cost.

578

579 **Loss Metric Section**

580 The loss metric captures the change in losses generated to serve a given amount of load. The
581 benefit for the loss metric was computed as the IRP Q5 updated power flow loss results less the
582 DFRTP (or Allocation Scenario) power flow loss results. The metric data are expressed in 2014
583 annual dollars. A positive value in the following table means that Alternative Project (or CAC
584 scenario) provides a benefit and a negative means it is a cost.

	Loss Benefit			
Beneficiaries	IPC TSP	NWE TSP	PAC TSP	PGE TSP
DFRTP	($777,137)	($66,699)	($251,599)	$84,846
CAC Scenario A	($922,591)	($263,766)	($538,304)	$79,960
CAC Scenario B	($635,839)	($218,289)	($419,039)	$79,959
CAC Scenario C	($398,958)	($163,716)	($307,395)	$53,306
CAC Scenario D	($62,337)	$27,286	($92,213)	($0)

585

586

587 **Reserve Metric Section**

588 The reserve metric evaluates the opportunities for two or more parties to economically share a
589 generation resource that would be enabled by transmission. The metric is a 10 year
590 incremental look at the increased load and generation additions in the NTTG footprint and the
591 potential combinations of transmission that may be included in the DRTP. The conclusion of
592 this analysis did not result in a reserve metric benefit for the Alternative Project.

593 *Initial Benefits and Beneficiaries*

594 This section is a summary of the benefits and Beneficiaries that are provided above. These
595 beneficiary values were provided to the CAC for Beneficiary calculations describe in the Cost
596 Allocation Worksheet.

597 Cost Allocation Worksheet

598 This worksheet follows the requirements of the cost allocation methodology outlined in
599 Attachment K to allocate the Alternative Project costs to Beneficiaries. The layout of the
600 worksheet is to state the Attachment K requirement (see boxed areas in the worksheet) and
601 then show the calculation(s) that implement the Attachment K requirement. The following
602 four steps summarize the cost allocation methodology.

603 Step 1: Verify whether or not the project is eligible for cost allocation. Application of the
604 verification criteria found that the Alternative Project passed the eligibility criterion since it was
605 an unsponsored project identified in the regional transmission planning process, was selected
606 in the DRTP and had capital costs of $2,744,026,994 exceeding the $20 million minimum.

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Step 2: For projects eligible to receive a cost allocation, the CAC shall start with the calculations provided by the Planning Committee and remove those entities that do not receive a benefit from the project being evaluated. Application of this step did not modify the initial net benefits provided by the Planning Committee.

Step 3: Before allocating a transmission project's cost, the CAC adjusts the calculated initial net benefits for each Beneficiary as follows:

a. The net benefits attributed in any scenario are capped at no less than 50% and no more than 150% of the average of the unadjusted, net benefits (whether positive or negative). Application of this criteria found that all Allocation Scenarios were between the upper and lower criterion values
b. If the average of the net benefits, as adjusted by (a) above, across the Allocation Scenarios is negative, the average net benefit to that Beneficiary is set to zero. Application of criterion b found that the Idaho Power Company, NorthWestern Energy and PacifiCorp Beneficiaries had negative average of the loss net benefit and were set to zero. The average of the net benefits for Portland General Electric was positive and was not set to zero. The capital cost average net benefit for all Beneficiaries were positive and were not set to zero.

Step 4: The adjusted net benefits, as determined by applying the limits in the two conditions above, were used for allocating project costs proportionally to Beneficiaries. However, Beneficiaries other than an Applicant will only be allocated costs such that the ratio of adjusted net benefits to allocated costs is no less than 1.10 (or, if there is no Applicant (as is the case with the Alternative Project), no less than 1.10). If a Beneficiary has an allocated cost of less than $100,000, the cost allocated to that Beneficiary is set to zero.

Attachment K provided the following two examples that further explained how to calculate this step.

Example 1:	Project Cost = $800M; B's adjusted net benefits = $483M; C's (Project Sponsor) adjust net benefits = $520M. B is allocated $385M (i.e., the lesser of $800M*($483/($483+$520)) = $385M <u>OR</u> $483M/1.1 = $439.1M) and C is allocated $415M (i.e., $800 – $385 = $415).
Example 2:	Same as Example 1, except Project Cost = $950M. B is allocated $439M (i.e., the lesser of $950M*($483/($483+$520)) = $457.5M <u>OR</u> $483/1.10 = $439.1) and C is allocated $511M (i.e., $950 – $439 = $511).

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The Alternative Project costs were allocated to Beneficiaries following the Attachment K methodology and the examples shown above. The following tables displays the final calculation for the cost allocation process.

	Loss Beneficiaries	Capital Cost Beneficiaries			
Beneficiary	PGE TSP	Q6 Incremental PAC BAA LSEs Load	Q6 WY Wind (New)	Q6 Incremental WY Gen (Existing)	Sum
Allocated Costs	$376,293	$876,019,460	$346,764,809	$535,094,780	$1,758,255,342

	Total	
Alternative Project Capital Cost	$2,744,026,994	
Beneficiary Allocation of Alternative Project Capital Cost	$1,758,255,342	
Remaining Costs	$985,771,652	Had the Alternative Project been a Sponsored Project or submitted by a stakeholder (each an "Applicant"), the Applicant could voluntary accept remaining project costs of $985,771,652. If the Applicant did not accept remaining costs the project would no longer be eligible for cost allocation.

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		In this case, since the Alternative Project is an unsponsored project identified by the Planning Committee there is not an Applicant to accept the remaining costs of the project. As a result, since all project costs cannot be allocated to Beneficiaries, the Alternative Project is not eligible for cost allocation.

The CAC satisfied the requirements in Attachment K in its completion of cost allocation analysis for the Alternative Project but as noted in the table above, since not all the costs were able to be allocated among Beneficiaries and there is no Applicant to accept the remaining project costs, the Alternative Project does not receive cost allocation.

Should cost allocation to the Alternative Project have occurred, it is important to note that when Beneficiaries of a project selected for cost allocation are identified and the costs of such project are allocated to the Beneficiaries, the results are predicated on several assumptions including:

1. The identification of Beneficiaries of a project, the dollar amount of benefits allocated to each Beneficiary, and the timing of those benefits are based upon the assumptions built into the models used to produce the allocations. Actuals may vary from assumptions; possibly substantially.
2. Each Beneficiary that is allocated a portion of a project's costs is assumed to receive a corresponding quantity of ownership rights or Ownership-Like Rights in the project in order realize the benefits that are assumed to be derived by the project.
3. The allocation of benefits to a Beneficiary is not intended to prejudice in any way the characterization of the costs or the further allocation of the costs by the Beneficiary as may be proscribed or allowed by Federal law, FERC order, or applicable law.

VI. NTTG 2014-2015 Draft Regional Transmission Plan Appendices

The appendices and 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-2014-2015-draft-final-regional-transmission-plan&Itemid=31.

A list and link to each of the appendices is also provided below:

Appendix A - NTTG 2014-215 Draft Regional Transmission Plan 02-11-2015

Appendix B - Revised NTTG Biennial Study Plan Approved 3-9-2015

Appendix C - Quarter 5 Additional Study Report - Evaluating Transmission Segments Similar to Energy Gateway

Appendix D - NTTG Study Plan for the 2014-2015 Public Policy Consideration Scenario - Final 02-11-15

Appendix E - NTTG Report for the 2014-2015 Public Policy Consideration Scenario – Final 05-03-15

Appendix F - New Resource Studies – UAMPS 540 MW Nuclear Generation at Antelope 230 kV Bus

Appendix G - New Resource Studies – 451 MW PURPA Generation within Idaho Power's Balancing Area

Appendix H - Cost Allocation Scenarios Discussion Paper_12-16-14

Appendix I – NTTG Revised Cost Allocation Study Plan Approved 06-03-15

Appendix J - Cost Allocation Calculation Workbook Final 06-29-2015

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