NORTHERN TIER TRANSMISSION GROUP

2012-2013 Biennial Plan
Cost Allocation Committee Report

Final Report

November 27, 2013

Approved by the NTTG Cost Allocation Committee: November 26, 2013
Approved by the NTTG Steering Committee: December 3, 2013

2012-2013 Cost Allocation Committee Report

Preface

To ensure efficient, effective, coordinated use and expansion of the members' transmission systems in the Western Interconnection to best meet the needs of customers & stakeholders.

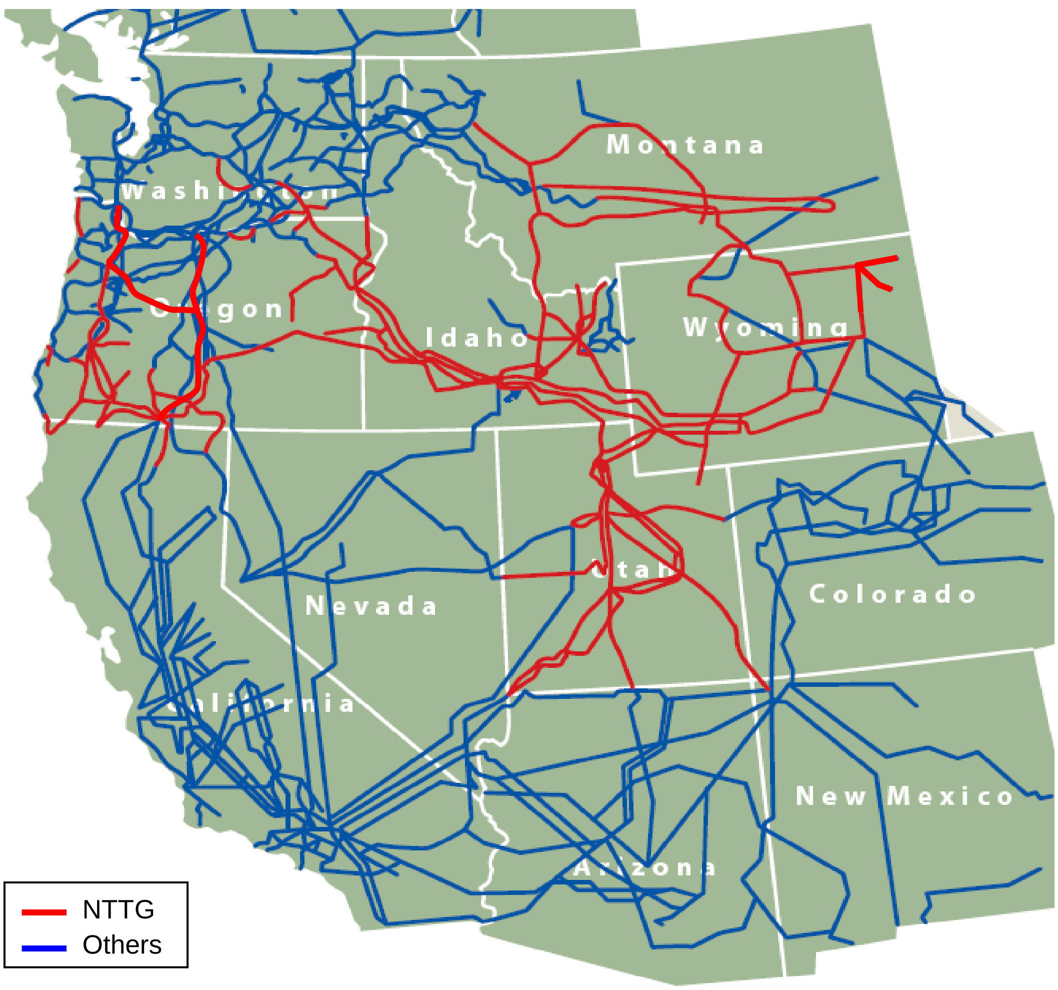

Figure 1: Map Illustrating Northern Tier Members' Principal Transmission Lines

NORTHERN TIER
TRANSMISSION GROUP

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Cost Allocation Committee Purpose

The Northern Tier Transmission Group created the Cost Allocation Committee ("Committee"), which purposes in this biennial cycle, in brief, were --

> "[t]o apply the Cost Allocation Principles consistently, openly and fairly while conducting analyses of cost allocation that accompany transmission project proposals developed in the NTTG planning processes and to make recommendations on cost allocations to the Steering Committee based on those analyses."

The Committee charter also called for the Committee to –

> "[r]epresent NTTG in regional and national transmission pricing, regulatory, and cost allocation forums."

Disclaimer

This disclaimer pertains to this entire Report:

This Cost Allocation Recommendation is created on behalf of the Northern Tier Transmission Group Cost Allocation Committee in conjunction with the Northern Tier Transmission Group's Biennial Transmission Plan per the Cost Allocation charter. Any statement regarding cost allocation is a recommendation only and not binding upon committee members or the Northern Tier Transmission Group Steering Committee.

If the state commission's designated representative (or alternate) is a member of the Committee, with respect to the Committee said individual is not acting as a representative of a state commission. No action or position taken by the individual or the Committee will preclude a state commission from taking contrary actions or positions in proceedings before it or other regulatory bodies.

The Committee's statements, positions, and/or recommendations shall not be framed as binding on individual state members and shall state clearly that each state retains its decision-making prerogatives. No action or position taken by a state commission's representative or by NTTG shall preclude a state commission from taking conflicting action consistent with its jurisdiction or constitute prejudgment of any issue in a proceeding before it.

Committee Introduction

The Northern Tier Transmission Group (NTTG) was formed voluntarily in 2007 to promote effective planning and use of the multi-state electric transmission system within the five-state footprint of Idaho, Montana, Oregon, Utah and Wyoming. NTTG is a regional planning group that fulfills the Federal Energy Regulatory Commission (FERC) Order 890 requiring local transmission providers to participate in regional and subregional planning and facilitates a robust and open transmission planning process in the NTTG footprint[1]. NTTG is managed by a Steering Committee composed of (1) state regulatory utility commissioners appointed by each state's respective regulatory utility commission in the Northern Tier footprint, (2) executive level representatives appointed from each utility, or utility cooperative, who is a party to the funding agreement of Northern Tier, and (3) representatives appointed by state customer advocacy groups within the Northern Tier footprint.[2]

The Cost Allocation Committee Charter establishes the Committee's purpose, principles, and responsibilities, as well as procedures and a process for the review of a project's benefits and cost allocation. Among the responsibilities of the Committee during this 2012-2013 biennial cycle were to "[r]eview proposed cost allocations for projects proposed in the NTTG planning process" and to "[m]ake recommendations on cost allocations for incorporation into the . . . biennial plans submitted to the Steering Committee."

[1] The NTTG Footprint means the geographical area comprised of the retail electric service territories of the entities enrolled in NTTG as Full Funders. Currently these Full Funders are (i) Portland General Electric Company (Portland General), (ii) PacifiCorp, (iii) Idaho Power Company, (iv) Deseret Generation & Transmission Co-operative, and (v) NorthWestern Corporation.

[2] In the respective compliance filings by the Full Funders of NTTG regarding the FERC Order 1000, the NTTG committee charters were substantially revised. Pursuant to these revisions to the charter of the Steering Committee, as of October, 2013 eligibility for membership in the Steering Committee has been broadened to include representatives of state transmission siting agencies within the NTTG footprint. In addition, the charter of the Cost Allocation Committee, as of October, 2013 has been expanded to include representatives of all the Full funders of NTTG. Although the current biennial cycle is not completed until December 31, 2013, for purposes of preparation and consideration of this Report, the membership, purpose and responsibilities of the Cost Allocation Committee are based on the prior Cost Allocation Committee charter established under Order 890.

Membership of the Committee during this biennial cycle was composed of one person appointed by each state regulatory commission and state consumer agency within the NTTG footprint and by each publicly-owned or consumer-owned entity which is a NTTG member. Entities with a representative on the Committee are –

- Idaho Public Utilities Commission
- Montana Public Service Commission
- Montana Consumer Counsel
- Utah Division of Public Utilities
- Wyoming Public Service Commission
- Wyoming Office of Consumer Advocate
- Deseret Power Electric Cooperative
- Utah Office of Consumer Services
- Utah Associated Municipal Power Systems.

The Committee elects a chairperson from its members annually. The Committee holds meetings as required to perform its responsibilities. For the 2012-2013 biennial cycle, conference calls were generally held bi-weekly. In addition, the Committee is required to have a minimum of two open stakeholder meetings per year. All NTTG Cost Allocation Committee meeting are open to the public.

While the Committee is specifically tasked with making recommendations on cost allocations to be incorporated in biennial plans and other analyses as needed to carry out its functions, it looks to project developers and sponsors and interested stakeholders to provide detailed data, analyses, and studies sufficient for the Committee to make recommendations with respect to proposed benefit and cost allocations. The Committee also has the responsibility of notifying the appropriate project entities that it has not been provided sufficient information to undertake its review.

As provided for by its charter, the Committee votes on any actions, decisions, or recommendations. Votes with respect to cost allocation are recorded as part of the Committee meeting minutes and available for review through the NTTG website.

Plan History

In the 2008-2009 Biennial Plan, the Committee compiled and considered information regarding sixteen transmission projects that were presented in the report of the Planning Committee. For the second planning cycle, 2010-2011, the focus of the Planning Committee was shifted from specific, proposed projects to a broader evaluation of transmission needs and options. This Committee, however, retained much the same process utilized in the prior planning cycle; that is, the Committee requested the dataset detailed in the Committee charter from each project sponsor for those projects for which data was submitted to the Planning Committee. Since most projects were included in the 2008-2009 report, the request made clear that the project sponsor could elect to provide only information that required updating.

In the 2010-2011 planning cycle, representation by the Committee was aimed in three areas: First, the Committee took an active role in preparing a NTTG position paper regarding the relationship between transmission planning and decisions to investment in new transmission projects. Second, as a follow-on to its work on the NTTG position paper, Committee members worked to have the distinctions between planning versus investment incorporated in the 10-year Regional Transmission Expansion Plan report prepared by the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC). Third, Committee members were also active in the preparation of comments submitted by NTTG in response to the Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation issued by the FERC, subsequently known as Order No. 1000.

2012-2013 Cost Allocation Committee Recommendation

In calendar years 2012 and 2013, the majority of the projects that were submitted to the Planning Committee had been submitted in the prior cycle. The Cost Allocation Committee Chairperson sent a letter to those entities which had submitted these projects noting that in the prior cycle (2010-2011) they did not ask for a NTTG cost allocation and requesting information on whether they wished to be considered for a NTTG cost allocation this cycle. All these entities responded that they did not wish to be considered for NTTG cost allocation.

For the few projects that were not submitted in the prior cycle, the Cost Allocation Committee Chairperson sent a letter to the sponsoring entity with a data request. The letter indicated that if an NTTG cost allocation was sought the data request would have to be completed and returned. The letter further stated that if the entity indicated it was not seeking a NTTG cost allocation, then the Cost Allocation Committee would take no further action. All sponsoring entities responded that they did not wish to be considered for NTTG cost allocation.

On the basis that no sponsoring entity requested an NTTG cost allocation for the biennial period 2012-2013, the Cost Allocation Committee makes no recommendations.

The entities contacted, and the projects they were contacted about, are listed in the Table below. Following that is a short description of each project considered.

Table of Transmission Projects Identified in 2012-2013

* indicates that this facility was included in the last cycle

Utility	Voltage	Project	Cost Allocation Status
Black Hills	230 kV	Teckla-Osage-Lange [WY]	The project is sponsored solely by Black Hills to serve network load and increase local reliability. Black Hills is not seeking a NTTG Cost Allocation recommendation.
Idaho Power Co.	500 kV	*Boardman-Hemingway [ID-OR]	Idaho Power expects costs will be directly allocated to users of the project according to existing policies and jurisdictional rate design and is not seeking a NTTG Cost Allocation Recommendation.
	500 kV	*Gateway West (with PacifiCorp) [WY-ID]	
NorthWestern Energy	230 kV	*AMPS line (Path 18) Upgrade [MT-ID]	Northwestern Energy expects costs will be directly allocated to users of the project according to existing policies and jurisdictional rate design and is not seeking a NTTG Cost Allocation Recommendation.
	500 kV	*Montana Intertie (Path 8) Upgrade [MT-WA]	
	230 kV	*MSTI Collector (up to 5 segments) [MT]	
	500 kV	*MSTI Project [MT-ID]	
PacifiCorp	500 kV	*Energy Gateway Central	PacifiCorp expects costs will be directly allocated to users of the project according to existing policies and jurisdictional rate design and is not seeking a NTTG Cost Allocation Recommendation.
	345/500 kV	*Energy Gateway South	
	500 kV	*Energy Gateway West	
	500 kV	*Hemingway-Captain Jack [ID-OR]	
	230 kV	*Walla Walla-McNary [WA-OR]	

Utility	Voltage	Project	Cost Allocation Status
Portland General	500 kV	*Cascade Crossing (Boardman-Salem) [OR]	With the suspension of the Cascade Crossing Project announced on June 3, 2013, PGE is not requesting cost allocation at this time.
Portland General	230 kV 230 kV 230 kV	Blue Lake-Gresham [OR] *Horizon-Keeler [OR] Pearl-Sherwood [OR]	PGE is not seeking cost allocation for the following PGE 230 kV Projects: Blue Lake-Gresham, Horizon-Keeler, and Pearl-Sherwood. It is also noted that the Horizon-Keeler 230 kV Project has been completed and is now in-service.
TransWest Express	600 kV	*TransWest Express DC line [WY-NV]	The TransWest Express Project has not yet reached the stage of development where it would be appropriate to ask NTTG to consider a cost allocation for the project.
<u>Facilities from Last Cycle not submitted in current cycle:</u>			
Grasslands Renewable	230 kV	Collector System [MT]	
	500 kV	DC line, Colstrip to Bismarck [MT-ND]	
TransCanada	500 kV	Chinook Project (AC+DC) [MT-ID-NV]	
	500 kV	Zephyr Project (AC+DC) [WY-ID-NV]	

2012-13 Transmission Project Descriptions

Black Hills Corp.

Teckla-Osage-Lange

The project includes two segments:

Teckla-Osage is approximately 60 miles of 230-kV transmission line consisting of 1272 ACSR Bittern conductor. The line would provide needed Common Use System (CUS) transmission capacity, accommodate projected load growth and increase Wyodak area stability margins. Reliability analysis for this project was initially performed as part of the 2008 BHBE LTP Study. Teckla and Osage substations will also be upgraded to support this line.

Osage-Lange consists of approximately 75 miles of 230-kV transmission line also consisting of 1272 ACSR Bittern conductor. The line would provide needed Common Use System (CUS) transmission capacity and provide an additional path into the Rapid City, South Dakota load center. Reliability analysis for this project was initially performed as part of the 2008 BHBE LTP Study.

Construction was delayed on both segments and scheduled to begin in 2013 with expected completion dates in 2015.

Idaho Power Company

Boardman to Hemingway

The project consists of a new, single-circuit 500-kV transmission line running approximately 300 miles from a new substation near Boardman, Oregon to the Hemingway substation, southwest of Boise, Idaho. The transmission line would span approximately 300 miles at an estimated cost of $890 to $940 million (2012 dollars). The project has achieved a WECC Phase 3 rating increase of the Idaho to Northwest path to 1,050 MW west-to-east and 1,000 MW east-to-west. As of January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and Bonneville Power Administration (BPA) to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager. In addition, a Memorandum of Understanding (MOU) was executed between the same entities to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway substation. In October 2012 BPA publicly announced their preferred solution to be the Boardman to Hemingway project. Idaho Powers asserts that an in-service date prior to 2018 is unlikely due to the current federal and Oregon state permitting process.

Idaho Power indicates that the project will meet native/network customer obligations. As a result, Idaho Power anticipates that project investment will be rolled-in to existing capital investment used in existing FERC and state regulatory rate processes.

Gateway West

Gateway West will consist of one 230-kV line from Windstar, Wyoming to Aeolus, Wyoming, a single 500-kV line from Aeolus to the Populus substation in Idaho (via an annex substation at Jim Bridger, Wyoming) and two 500-kV lines from Populus to Hemingway The, two 500-kV lines would be built in a generally east-west orientation, with one taking a more northerly route running through Borah and Midpoint, and the other through a new substation named Cedar Hills. A single 500-kV line would tie together the two 500-kV routes from Midpoint to Cedar Hills. The fully completed project from Populus to Hemingway is expected to provide 3,000 MW of transfer capacity. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint, which is constructed as a 500-kV line presently operating at 345 kV. The 345-kV line will be converted to 500-kV operation in the future. The Gateway West project is engaged in the federal permitting process established by the National Environmental Policy Act (NEPA). The Bureau of Land Management (BLM) is the lead agency administering the NEPA permitting process. On April 26, 2013, the BLM publically released the Final Environmental Impact Statement (FEIS) for comment which is a significant milestone in the NEPA process. A Record of Decision (ROD) is expected by the end of calendar year 2013. The multi-phase project is scheduled for line segments to be in-service between 2019 and 2023.

NorthWestern Energy

AMPS Line Existing Path 18 Upgrade

The project is described as involving series compensation on the 230-kV AMPS line (from the AMPS substation in Idaho to the Mill Creek Substation in Montana) and the addition of appropriate reactive devices. NorthWestern will own the 46 MW increased southbound transfer capacity. NorthWestern has completed the WECC path rating process for this and has confirmed transmission service agreements for the increased capacity.

Montana Intertie Path 8 Upgrade (Existing 500-kV Upgrade)

This project involves the “Colstrip Transmission System” located in NorthWestern’s balancing area between Colstrip and Townsend, Montana and the existing BPA 500-kV transmission from Townsend, Montana, to the Northwest (currently called Montana to Washington). The project would increase transfer capacity through increase of series compensation. The increased capacity would be used to satisfy transmission service requests.

Mountain States Transmission Intertie (MSTI)

The project consisted of a new, single-circuit 500-kV line from Townsend, Montana to Midpoint, Idaho, plus new and upgraded substations and microwave communications system. Total line miles were estimated at 420-445 miles at a cost of $1.0 billion. According to studies referenced by NorthWestern, the project could be used in conjunction other transmission system additions to economically transmit renewable generation in Montana to southern Nevada and California.

NorthWestern expected a north-to-south rating of 1,500 MW and south-to-north rating of 1,100 MW. All technical studies for the WECC Phase 2 path rating process had been completed.

NorthWestern proposed to use an open-season process for transmission customers to commit to a level of transmission service on the MSTI project and to pay an associated transmission rate based on project costs (including rate of return). NorthWestern did not propose to allocate any project costs to calculation of its existing transmission rates.

NorthWestern provided excerpts and summaries of information developed as part of the 2010 Study Program of TEPPC with respect to the MSTI project. The economic study results indicated that the MSTI project, coupled with other transmission system additions, could provide a less expensive alternative for the development and delivery of renewable resources into southern Nevada and California. The information provided by NorthWestern directly, or by reference to the TEPPC studies, did not indicate what might be the full range of net benefits resulting from the MSTI project (e.g., reliability, deferral of other transmission projects, regulation and contingency reserve impacts, etc.), nor the distribution of benefits among transmission systems, transmission customers, and generation developers and operators. NorthWestern made clear that the development concept underlying MSTI is for prospective entities to self-select themselves as likely beneficiaries of the project and seek participation accordingly.

NorthWestern also provided a copy of its Phase 2 rating progress report to WECC.

Due to market uncertainty and other factors this project is no longer under consideration by NorthWestern at this time.

MSTI Collector System

This project represented an aggregation of relatively short transmission system additions necessary to connect the anticipated development of new wind projects with a new, 500-kV substation at Townsend, the proposed northern terminus of the MSTI project. NorthWestern expected that there would be five of these "generator lead" lines, all radial, connecting to Townsend. The size, configuration, length, and location of the Collector System lines would be based on those entities committing to transmission service through an open-season process.

Since there was only a broad, conceptual description of the project, no cost/benefit analysis at an aggregate or disaggregated level was prepared for the project. NorthWestern intended to allocate costs (i.e., recover its costs) through its normal open-access transmission tariff (OATT) or transmission rate methodology. That is, transmission customers on the Collector System would pay the greater of (i) NorthWestern's OATT rate or (ii) an incremental rate based on the costs and capacity of the Collector System.

Due to market uncertainty and other factors this project is no longer under consideration by NorthWestern at this time.

PacifiCorp

PacifiCorp included the evaluation of transmission alternatives as part of both its 2011 and 2013 Integrated Resource Plan (IRP). (That is, transmission options were explicitly considered in evaluating the net costs and risks of various resource portfolios). The conclusion was that, as a whole, the Gateway strategy would be cost-effective based on the IRP scenarios

While the 2011 IRP evaluations provided an indication of benefit versus cost of the transmission build-out in total, it did not clearly disaggregate the results (i) among the various components of the Gateway strategy, (ii) among types of benefits, or (iii) among beneficiaries. This type of analysis could, perhaps, be expanded in the future to provide at least some significant portion of the information necessary to estimate benefits by type and among various beneficiaries. In their 2013 IRP, PacifiCorp introduces an expanded analysis tool called the System Operational and Reliability Benefits Tool (SBT) as another method to further analyze the benefits of transmission projects. After filing their 2013 IRP in April 2013, PacifiCorp established a stakeholder group and scheduled workshops to further review and develop the SBT.

Energy Gateway

This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.
November 2013

Energy Gateway Central

Energy Gateway Central consists of two project sub-segments and together is known as "segment B and C". The first segment, segment B, Populus to Terminal, was completed in 2010 and is currently in service. The second segment, segment C consists of two sub-segments, Mona to Oquirrh and the Oquirrh to Terminal lines. Mona-Oquirrh is approximately 100 miles and is comprised of a single, 500-kV sub-segment from Clover (adjacent to Mona) to Limber and a double-circuit, 345-kV sub-segment from Limber to Oquirrh. This segment was completed in May 2013 and is currently in service. Oquirrh to Terminal is approximately 14 miles consisting of double-circuit 345-kV facilities estimated to be in-service June 2016. The project initially (i.e., prior to completion of future Gateway segments) is expected to increase transfer capability by 700 MW bi-directionally.

As with other portions of the Gateway Project, Gateway Central was constructed in order to meet “current and projected network load service” as well as maintain its compliance with reliability performance standards.

Energy Gateway South

Energy Gateway South consists of two project sub-segments and together is known as “segment F and segment G”. The Aeolus-Mona line is about 400 miles of a single, 500-kV line from a new substation in central Wyoming to the Mona substation in central Utah. Permitting is underway and the updated scheduled completion is in the 2020-2022 timeframe and has an expected rating of 1,500 MW north-south. This segment is also referred to as “segment F”.

The segment of Gateway South from Mona to Crystal, Nevada has been deferred indefinitely.

No information is available regarding the expected capital costs of Gateway South. The Gateway South Project is being constructed in order to meet current and projected network load service and to meet reliability requirements. As with all Gateway segments, all costs are intended to be recovered as part of PacifiCorp’s overall transmission system costs. The second segment, Segment G, Sigurd to Red Butte consists of a single-circuit, 345-kV line running approximately 170 miles from the Sigurd substation in central Utah to the Red Butte substation near the Utah-Nevada border. Construction began in May 2013 and is estimated in-service in June 2015.

Energy Gateway West

The Windstar-Populus transmission project consists of three key sections: (i) one, single-circuit, 230-kV line running about 75 miles from the existing Windstar substation to Aeolus in central Wyoming; (ii) 140 miles of a single, 500-kV line from the new Aeolus substation to a new annex substation near the existing Bridger substation in western Wyoming; and (iii) approximately 200 miles of a single-circuit 500 kV line from the new annex near Bridger to a recently constructed Populus substation in southeast Idaho. PacifiCorp expects this eastern segments, also referred to as “segment D”, to be completed in the 2019-2021 timeframe.

Segment D would provide transfer capability from an area with rich, diverse resources, consistent with use of transmission to meet the future resource needs of its retail and wholesale customers.

The western segment or “segment E” of this project consists of (i) a single, 500-kV line from Populus to a new substation south of Midpoint (Cedar Hill); (ii) a single, 500-kV line from Midpoint to the Hemingway substation south of Boise, Idaho; and (iii) a single, 500-kV line from Cedar Hill to Hemingway substation. The total segment E is approximately 500 miles. PacifiCorp expects this western segment will be completed in the 2020-2023 timeframe. Segment E will provide access to existing and new generating resources to serve retail and wholesale loads.

Hemingway - Captain Jack

The project as originally proposed was a single-circuit 500-kV line that would run approximately 375 miles from the Hemingway substation in western Idaho to the BPA's Captain Jack substation. PacifiCorp is pursuing joint development opportunities with regional entities on alternatives to this proposed configuration. To that end, in January 2012 PacifiCorp signed the Boardman to Hemmingway Permitting Agreement with Idaho Power and BPA which provides for PacifiCorp's participation through the permitting phase of the project.

Walla Walla - McNary

PacifiCorp has placed the Walla Walla – Wallula segment on hold pending further review with no scheduled completion date. The project will be moved forward as required to serve customer needs. The project is a new, single-circuit 230-kV line that will run approximately 56 miles between Walla Walla, Washington and Umatilla, Oregon and will connect existing substations at Walla Walla, Wallula and McNary. PacifiCorp has completed the local permitting of the 30 mile Wallula - McNary portion or "segment A" of the Energy Gateway. Estimate and service date for Segment A is driven by customer needs

Portland General

Cascade Crossing

The project consists of a single-circuit, 500-kV transmission line from Portland General's Coyote Springs generator, located near Boardman, Oregon, to its Bethel Substation. The line's total length would be approximately 210 miles and Portland General proposes a path rating of approximately 1,500 MW. This project is proposed to satisfy several generator interconnection requests, including a substantial number of renewable/wind projects (totaling approximately 2,100 MW). If the level of commitment from the open-season process exceeds the capacity of a single circuit, the project would be re-designed to include a second 500-kV circuit from the Grassland Substation to BPA's Santiam Substation.

The project is described as having five, right-of-way segments; (1) Coyote Springs to a new substation at Grassland; (2) Grassland to a new Cedar Spring substation near Arlington, Oregon; (3) Cedar Springs to a new substation near Mikkalo, Oregon; (4) Mikkalo to Bethel; and (5) from a tap on the Mikkalo-Bethel segment to BPA's Santiam Substation (only required if a second circuit is developed).

Portland General is discussing some form of possible joint participation in this project with BPA, PacifiCorp and Idaho Power. Portland General had estimated a January 2017 in-service date for this project; however, on June 3, 2013 Portland General announced a suspension status of the Cascade Crossing project due to a MOU with BPA to pursue ownership of regional transmission capacity to meet Portland General's customer needs[3].

Blue Lake-Gresham

This is a new 230-kV transmission line from Portland General's Blue Lake Substation in Troutdale, Oregon to Portland General's Gresham Substation in Gresham, Oregon. The distance is approximately 4.2 miles and the expected in-service date is June 2018.

Horizon-Keeler

This is a Portland General transmission project to install 230/115-kV, 320 MVA auto transformer at Sunset Substation located in Hillsboro, Oregon. This project requires construction of a new 230-KV transmission line from Horizon Substation to BPA's Keeler Substation. The distance for the new line is approximately 1 mile. The project was completed on June 2012.

Pearl-Sherwood

This is a joint Portland General and BPA project to re-terminate the existing 230-kV double circuit tower line operating as a single 230-kV line into two separate 230-kV lines between BPA's Pearl Substation and Portland General's Sherwood Substation. This project requires an additional two 230-kV breakers at each substation. This project has been deferred beyond the ten-year planning horizon; the projected in-service date is summer 2024.

TransWest Express LLC

TransWest Express

The TransWest Express Transmission Project is a high-voltage (HV), DC regional electric transmission system proposed to reliably deliver cost-effective renewable energy produced in Wyoming to the Desert Southwest region (California, Nevada and Arizona). The project has been under development since 2005 with an anticipated 2014 start of construction. The project specifications include 3,000 MW capacity and 725 miles of 600-kV HVDC transmission line. The estimated project cost is $3 billion, with an approximate 3-year construction timeline.

The Northern Terminal will be approximately 50 miles west of the planned Aeolus substation. There will be an initial connection to Platte-Latham 230 kV line with future connections to planned Gateway West and Gateway South 500-kV lines. The Southern Terminal in Eldorado Valley with 500-kV connections to the Mead-Marketplace Line, the McCullough substation, and the Eldorado substation.

In July 2013, the BLM and Western published a draft Environmental Impact Statement (EIS) and a series of public meetings are scheduled in Wyoming and Utah.

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[3] As of November 1, 2013, this project has been terminated.

Other Committee Activities

FERC Order No. 1000 -- Regional

FERC Order 1000 directs transmission providers to develop methodologies and procedures consistent across the transmission planning region for allocating the costs of certain projects in the regional transmission plan among entities determined to be beneficiaries of a project.

To develop the regional cost allocation methodology and procedures, NTTG members formed the Cost Allocation work group (CAWG), comprised of the Cost Allocation Committee members and the NTTG funders not otherwise having representatives on the Cost Allocation Committee. The CAWG members engaged in a robust process to develop a cost allocation methodology consistent with the principles set forth in the Order. Given the diverse membership of the CAWG, a significant level of negotiation and compromise was required. The CAWG held well over fifty meetings including working group meetings, joint meetings with the NTTG Transmission Planning work group, and stakeholder outreach meetings. In addition to the regular and joint meetings, the CAWG also held two workshops for presentation and review of FERC-approved cost allocation methodologies for independent system operators (ISOs) and regional transmission organizations (RTOs). Specifically, the CAWG reviewed the methodologies of the Midwest ISO (MISO), New York ISO (NYISO), California ISO, PJM, and the Southwest Power Pool (SPP).

The CAWG members also prepared detailed reports on the cost allocation methodologies of SPP, PJM, NYISO and MISO in an effort to understand how their cost allocation methodologies and benefit metrics could be applied to the NTTG region. The CAWG concluded that the RTO/ISO methodologies were not appropriate for the NTTG region because of the absence of an ISO/RTO or tight power pool within the NTTG region, and, as a result, that transmission benefits would not flow comparably. The CAWG also concluded that a postage stamp methodology would not meet the “roughly commensurate” test prescribed in the Order for the NTTG footprint.

Development of the cost allocation procedures required agreement on the benefit metrics that would be considered by NTTG; on how benefits would be estimated; and on how the procedures would deal with uncertainty and risk.

The result was the CAWG’s proposal to use three benefit metrics to assess the potential benefits (or costs) to an entity as the result of a transmission project: a change in annual capital-related transmission costs; a change in energy losses; and a change in reserve costs.[4] The

[4] Considerable effort was also directed towards studying the use of production cost modeling in order to capture additional benefits for potential use in cost allocation. The team concluded, however, that the results of the study in the current modeling framework do not provide sufficient accuracy to be used at this time in the development of benefit metrics for the allocation of transmission project costs.

CAWG also developed criteria to limit the results of one (or a few) scenarios from substantially affecting the overall result for an individual beneficiary and to limit the allocation of costs to that of the project capital costs and not cost impacts that may be indirectly incurred by entities as a result of the project.

The filing utility members of NTTG filed changes to their OATTs regarding the Order 1000 regional requirements on October 12, 2012. On May 17, 2013 the FERC issued an order regarding these filings, accepting the NTTG cost allocations in part, and rejecting them in part. In sum, the FERC for the most part accept the benefit metrics put forward for cost allocation, but either rejected or required justification or modification for the criteria that would potentially limit the scenario benefits attributed to an entity.

The Cost Allocation Committee, through its participation in the CAWG, worked with the Planning and Legal work groups to craft the compliance filings of the filing utility members of NTTG responding to the May 17th FERC order.

FERC Order No. 1000 – Interregional

FERC Order 1000 also directs transmission providers to develop consistent methodologies and procedures between transmission providers in different transmission planning regions to allocate the costs of interregional transmission projects, provided that the interregional transmission project must still be included in the each affected regional plan for purposes of cost allocation. (Order 1000 also includes requirements regarding coordination with other regions, stakeholder participation, etc.)

To accomplish these interregional filing requirements, the four transmission planning regions in the Western Interconnection formed planning, cost allocation and legal work groups, staffed with members from their individual regional committees and work groups. Several members of the Cost Allocation Committee, through their participation in the CAWG, also participated in the negotiation of common language among the four regions for interregional cost allocation. This common language was adopted by the four regions and, ultimately, by the transmission providers in each region for inclusion in the Attachment K of their respective OATTs.

The development of the common language for the interregional filings began almost immediately after the October 2012 regional filings and continued into the spring of 2013, involving numerous, in-person negotiations, conference calls, and several stakeholder meetings. The filing utilities of NTTG filed the common language for interregional coordination and cost allocation on May 10, 2013.

Charter Revision

In its Order 1000 regional filing, the filing utilities indicated to the FERC that NTTG intended to revise its steering, planning and cost allocation committee charters to reflect modification of the regional planning and cost allocation practices. Based on this representation, the FERC order on Order 1000 regional compliance required the filing utilities to file these revisions within the same120-day period set for required revisions to the OATTs.

The changes to the cost allocation charter generally fall into one of two categories: (1) removing the detailed description of the cost allocation process and methodology, which are descriptions are, or will be, incorporated into either the Attachment K's of each filing utility's OATT or the Planning and Cost Allocation Practice document and (2) changing the governance structure with regard to eligibility for membership, voting classes and requirements, and other related governance and procedural matters. These changes in governance are expected to result in expanded membership, voting by membership class, and specific voting thresholds for approval.