NORTHERN TIER TRANSMISSION GROUP

2008-2009 Biennial Plan

Cost Allocation Committee

Draft Report

July 1, 2009

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

Contents

Preface i
Contents ii
Summary 1
Committee Introduction 4
Data Request to Project Sponsors 5
Project Summaries 6
APPENDICES 13
Appendix A: Data Request to Project Sponsors 14
Appendix B: Project Templates 21
Project 1: Hughes Transmission Project 22
Project 2: Wyodak South Project 26
Project 3: Mountain States Transmission Intertie 30
Projects 4-12: Energy Gateway Project (including Projects 14 & 15 Hemingway-Captain Jack and Walla Walla-McNary) 34
Projects 9-12: Gateway West (Idaho Power) 41
Project 6 & 7: Energy Gateway Central 46
Project 13: Boardman – Hemingway 56
Project 16: Southern Crossing 62

Summary

The Northern Tier Transmission Group created the Cost Allocation Committee ("Committee"), which primary purpose is --

> "To 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."

There are sixteen projects studied as part of the 2008-2009 Biennial Plan, each representing a single- or multiple-owner transmission segment identified by the project sponsor(s). These projects are planned for a variety of reasons, which include support of retail and wholesale network load growth; maintenance and improvement of reliability; meeting requests in the transmission providers' queues; access to new and existing generation resources and markets; and support of projected, but non-specific, transfers of power from regions rich in renewable resource potential to regions with concentrated loads.

Project 1: Hughes Transmission Project

Project 2: Wyodak South Project

Project 3: Mountain States Transmission Intertie

Project 4: Gateway South, Segment 1: Mona – Crystal

Project 5: Gateway South, Segment 2: Aeolus – Mona

Project 6: Gateway Central: Populus – Terminal Segment

Project 7: Gateway Central: Mona – Oquirrh Segment

Project 8: Gateway Central: Sigurd – Red Butte – Crystal Segment

Project 9: Gateway West, Segment 1A: WindStar – Bridger

Project 10: Gateway West, Segment 1B: Bridger – Populus

Project 11: Gateway West, Segment 1C: Populus – Midpoint

Project 12: Gateway West, Segment 1C: Midpoint – Hemingway

Project 13: Boardman – Hemingway

Project 14: Hemingway – Captain Jack

Project 15: Walla Walla – McNary

Project 16: Southern Crossing

On behalf of the Committee, the chair, Lou Ann Westerfield, sent a letter to each transmission project sponsor formally requesting specific information related to the development of a draft cost allocation recommendation. Each project sponsor responded to the Committee's data request.

Each project was assigned a liaison from the Committee to review the information supplied by the project sponsor, to coordinate clarification and augmentation of the sponsor's initial response, and to complete a standard project template utilizing the information supplied by the sponsor. Each project was discussed at length on the Committee's conference calls. Based on review and consideration of the information supplied by the project sponsor, in particular its proposed cost allocation methodology, the Committee has either (i) made a recommendation with respect to a project or (ii) determined that there is insufficient information or the project is too immature to recommend a cost allocation. The Committee's actions with respect to each project are summarized below. In several instances the action is not "final" and may be modified as new information is received regarding the project's scope, purpose, configuration, or participation by other parties.

Table 1: Committee Action on Proposed Projects

Project Segment	Action
Hughes Transmission Project (Basin Electric Power Cooperative)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Wyodak South Project (Black Hills Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Mountain States Transmission Intertie (NorthWestern Energy)	No recommendation: Costs will be borne by subscribers
Gateway South: Mona-Crystal (PacifiCorp)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway South: Aeolus-Mona (PacifiCorp)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway Central: Populus Terminal (PacifiCorp)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway Central: Mona-Oquirrh (PacifiCorp)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway Central: Sigurd-Red Butte-Crystal (PacifiCorp)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway West: WindStar-Bridger (PacifiCorp and Idaho Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers

Gateway West: Bridger-Populus (PacifiCorp and Idaho Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway West: Populus-Midpoint (PacifiCorp and Idaho Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Gateway West: Midpoint-Hemingway (PacifiCorp and Idaho Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Boardman – Hemingway (Idaho Power)	Recommend cost allocation as proposed: rolled-in to all transmission customers
Hemingway – Captain Jack (PacifiCorp)	No action: Final project configuration TBD
Walla Walla – McNary (PacifiCorp)	No action: Final project configuration TBD
Southern Crossing (Portland General Electric)	Recommend cost allocation as proposed, pending further clarification on cost allocation principles: rolled-in to all transmission customers

Committee recommendations are non-binding on Committee members, the entities they represent, and the NTTG Steering Committee, pursuant to the Committee's Charter. Thus, the following 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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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 Committee Charter establishes its purpose, principles, and responsibilities, as well as procedures and a cost allocation process. Among the responsibilities of the Committee are 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."

Membership of the Committee is 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
- Oregon Public Utility Commission
- Montana Public Service Commission
- Montana Consumer Counsel
- Utah Public Service Commission
- Wyoming Public Service Commission
- Wyoming Office of Consumer Advocate
- Deseret Power Electric Cooperative
- Utah Associated Municipal Power Systems

The Committee elects a chairperson from its members every two years. The Committee holds meetings as required to perform its responsibilities. For the past 6 months this has generally resulted in weekly conference calls. In addition, the Committee is required to have a minimum of two open stakeholder meetings per year.

While the Committee is specifically tasked with making recommendations on cost allocations to be incorporated in the annual and 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 proceed with 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.

Data Request to Project Sponsors

As indicated, the key to the Committee's work is receipt of complete and timely information from project sponsors and interested stakeholders regarding project costs, benefits, purposes (e.g., reliability, economic congestion, inter-regional transfers, etc.), and optional configurations. The Committee Charter enumerates the basic information in the "application package" (Section V.1.) that should accompany a project proposal submitted for inclusion in the NTTG Planning Process. This information list includes –

- Cost/benefit analysis
- Proposed cost allocation
- Proposed cost recovery
- A risk and benefit analysis focusing on the distribution of costs, benefits and risks among the parties proposed to share in the cost allocation of the project
- How each NTTG cost allocation principle was applied in the analysis.

To facilitate its receipt of information from project sponsors, the Committee assigned individual members to each project to serve as a liaison and non-exclusive point of contact with the project sponsor. The Committee also developed a template to organize in a consistent manner and summarize project information.

Notwithstanding the direction set forth in the Committee Charter, project sponsors generally failed to timely provide an application with the required information. While the project liaisons worked with the sponsors to gather this information, the results were mixed and generally incomplete and tardy. In a push to complete its work, the Committee prepared a standardized data request in letter format formally requesting specific information related to the development of a draft cost allocation recommendation. (The form letter is provided in Appendix A.) This letter was sent to each project sponsor in early June 2009 by the Committee Chair, Lou Ann Westerfield. Each project sponsor has responded to the data request, either partially or completely. In several instances the Committee has gone back to the sponsor to request clarification or supplemental information. These responses are the basis for the Committee's action with respect to a project and are summarized below. Each completed template, by project segment, is set forth in Appendix B.

It should be noted that project review and recommendations of the Committee are with respect to the issues of cost allocation and cost/benefit allocation only. Although the Committee reviews information with regard to project design, alternatives, costs and benefits, it makes no determination as to the need, prudence, or cost-effectiveness of a proposed project.

Project Summaries

Hughes Transmission Project

The project sponsor is Basin Electric Power Cooperative. The project consists of three, new, single-circuit 230-kV line components: (1) Hughes-Dry Fork, (2) Dry Fork-Carr Draw, and (3) Dry Fork-Sheridan, all at 230-kV. Total line miles are 143 miles at a cost of $82.9 million. The project is under construction with an expected in-service date expected of November 2009. According to Basin, the project will provide for forecasted network load growth and integrate a new 390 MW generation station at Dry Fork. Basin proposes to allocate 100% of project costs to Basin's transmission customers for recovery in FERC-approved rates.

Committee Action:

The project is a multiple use project. Cost of the project will be recovered through FERC approved tariff; project is already under construction with in-service date of 4th Quarter 2009. The proposed cost allocation methodology is consistent with the NTTG cost allocation principles.

Wyodak South Project

The project sponsor is Black Hills Power. The project consists of two, new, single-circuit 230-kV line components: (1) Donkey Creek-Pumpkin Buttes and (2) Pumpkin Buttes-Dave Johnston area. Total line miles are estimated at 118 miles at a cost of $53 million (2008 dollars). The first component of the project is in-service and the estimated in-service date of the second component is November 2010. According to Black Hills, the project will provide for network load growth, improve reliability for existing load, and provide capacity for new point-to-point transmission service requests. Black Hills proposes to allocate 100% of project costs to a common-use transmission system of Black Hills, Basin Electric, and Powder River for recovery in the FERC-approved rates of the joint OATT tariff.

Committee Action:

This project is a multiple use project. Cost recovery for this project will be obtained thru a FERC approved OATT. Part of the project is already completed and in-service. The proposed cost allocation methodology is consistent with the NTTG cost allocation principles.

Mountain State Transmission Intertie

The project sponsor is Northwestern Energy. The project consists of a new, single-circuit 500-kV line from Townsend, Montana to Midpoint, Idaho. Total line miles are estimated at 430 miles at a cost of $1.0 billion. The estimated in-service date is 2013. According to Northwestern the project will provide capacity to meet transmission service requests and relieve constraints in the high-voltage transmission system. Northwestern had proposed to use an open-season process through which the project capacity and costs would be assigned to various entities based on their subscriptions to this "merchant" project. The FERC rejected the "merchant" project proposal and stated that a comparable project could be constructed on a cost-of-service basis, with appropriate tariff waivers. As a result, Northwestern may file for tariff waivers in order to recover costs only from those users of the transmission project and to isolate its native load from such costs.

Committee Action:

The Cost Allocation Committee will not be making a cost allocation recommendation on the MSTI project due to the uncertainty surrounding the FERC declaratory order on June 18, 2009. Northwestern's commitment to moving forward with MSTI as a traditional cost of service project has not been fully addressed by Northwestern Energy or the Cost Allocation Committee. The Cost Allocation Committee intends to re-evaluate the MSTI project once Northwestern Energy provides additional information.

Energy Gateway South, Central, and West Project

The project sponsor is PacifiCorp and, for certain portions, Idaho Power Company. In the Biennial Plan, Energy Gateway South, Central, and West consist of nine project segments. (The Gateway Project also includes two additional segments, Hemingway-Captain Jack and Walla Walla-McNary, which segments are addressed individually below.) While each project segment is being planned as part of a whole, each is also being pursued with various regulatory and permitting agencies based on each project segment's unique requirements (e.g., differing voltages, number of circuits, construction timing, permitting, etc.). Idaho Power will be a joint participant in the project segments comprising Gateway West, which include Windstar-Bridger, Bridger-Populus, Populus-Midpoint, and Midpoint-Hemingway. PacifiCorp confirms that each project segment, while nominally part of a "super" project, will be justified individually. (See "PacifiCorp – 2008 IRP, Chapter 4.) The bulk of information required to be submitted by PacifiCorp to the Committee addressed the overall project, not individual segments, although it provided basic information as to the permitting and construction status of the most advanced of the project segments. PacifiCorp filed and received a Certificate of Public Convenience and Necessity (CPCN) for the Populus-Terminal project segment from the Idaho Public Utilities Commission and Utah Public Service Commission and recently filed with the Utah Public Service Commission a Notice of Intent to file an application for a CPCN for the Mona-Oquirrh project segment. It has also made right-of-way filings with the Bureau of Land Management (BLM) for several of the project segments, a filing being made with BLM for each segment, rather than the overall project. Each project segment would be placed in-service as completed, with earliest occurring in 2010 and the latest occurring sometime after 2017 (if eventually constructed).

In addition to its original information submittal, PacifiCorp responded to the Committee request to break down its cost estimates by project segment, as set forth below in Table 2.

Table 2: Gateway South, Central, and West Estimated Project Costs by Segment (Without AFUDC)

Project Segment	Estimated Cost (nominal dollars)
Gateway South: Mona (Sigurd)-Crystal	$745 million
Gateway South: Aeolus-Mona	$782 million
Gateway Central: Populus-Terminal	$815 million
Gateway Central: Mona-Oquirrh	$569 million
Gateway Central: Sigurd-Red Butte-Crystal	No information
Gateway West: WindStar-Bridger	*See total below*
Gateway West: Bridger-Populus	*See total below*
Windstar-Populus *	$1.37 billion
Gateway West: Populus-Midpoint	*See total below*
Gateway West: Midpoint-Hemingway	*See total below*
Populus-Hemingway *	$821 million
Hemingway – Captain Jack	$931 million
Walla Walla – McNary	$87 million

* This estimate by PacifiCorp for Gateway West totals $2.191 billion. Idaho Power estimates its cost for Gateway West will be $600 million.

As to proposed cost recovery, PacifiCorp has informally adopted an approach of so-called project "Stages." "Stage I" refers to the configuration (i.e., voltage, number of circuits, etc.) of each project segment which is justified to meet reliability requirements for current and forecast native load and committed point-to-point (PTP) transmission service, and to deliver renewable (and, presumably, any other) resources to its native load. "Stage II" refers to the potential modification of a project segment's Stage I configuration so as to satisfy new transmission service requests, either in its existing queue or responding through an open-season process, by approximately doubling the capacity of that project segment (from approximately 1500 MW to 3000 MW). In defining the Stage I project configurations as those transmission facility additions necessary to satisfy the capacity and reliability requirements of native load and existing PTP, PacifiCorp naturally proposes to roll-in Stage I investment and related costs to its rate base and transmission revenue requirements.

In contrast, PacifiCorp proposes to recover Stage II investment and related costs by first grouping its transmission queue requests to align with project segments (which would result in two groups) and then offering five-year contracts with rates sufficient to recover the incremental Stage II costs that exceed PacifiCorp's expected rolled-in (i.e., embedded) transmission rates; after five years, the customers taking transmission service in the Stage II category could continue service thereafter at embedded transmission rates. Due to the incremental costs associated with State II costs, PacifiCorp does not expect that there will be sufficient demand for new transmission service to support upgrading the project configuration for the additional 1500 MW of capacity.

Idaho Power expects to participate with PacifiCorp in the project segments comprising Gateway West, from Windstar to Hemingway. Idaho Power estimates its portion of Gateway West will cost $600 million and proposes to apply FERC's existing rate policies with respect to cost recovery. This approach will include direct assignment of project costs to users of the project segments. Depending on final per-unit costs of the project segments, the application of the FERC's "or" pricing policy (i.e., "higher of" FERC rate) may result in project users paying a rate in excess of Idaho Power's embedded rates, analogous to PacifiCorp's proposal for Stage II project configuration costs.

Committee Action:

<u>Gateway West, South, and Central (except for Segments B&C)</u>

The Committee recommends proportional cost allocation to network customers on the basis of meeting existing and projected service and reliability obligations. The Committee will review this recommendation if and when potential third-party users make sufficient commitments.

<u>Gateway West (Idaho Power)</u>

The Committee recommends the proposed proportional allocation to network customers on the basis of meeting existing and projected service and reliability obligations. The Committee will review this recommendation if and when potential third-party users make sufficient commitments.

<u>Gateway Central: Populus – Terminal & Mona – Oquirrh (Segments B & C)</u>
"For PacifiCorp the core purpose of the Energy Gateway is to serve network load requirements. However, the investments now known as Energy Gateway, meet multiple needs for PacifiCorp's network customers, including projects already in the Company's 10-year business plan to meet projected load growth, deliver planned network resources, reduce congestion, and improve system reliability. These additional investments are necessary to relieve transmission capacity shortage limiting delivery of new generation resources to network customers throughout PacifiCorp's service area." (June 13, 2009 data response).

According to PacifiCorp's FERC filing the additional transmission infrastructure and the "hub and spoke" design will provide flexibility, improve efficiency and enable development of clean and renewable energy resources and will ensure that PacifiCorp's system will be capable of meeting future regional needs. (PacifiCorp Petition at 8 and 9).

The Cost Allocation Committee is evaluating this project on a whole based solely on the project's stated need to meet network load obligation and growth of existing customers as well as to meet reliability needs. However, there may be a variety of drivers for the project as a whole, such as third party providers. Therefore, the CAC is not addressing these other drivers of the project. The Gateway project will be treated as a comprehensive interdependent effort to upgrade reliability and provide more access to resources on all sides of the system. The CAC has reservations due to the uncertainty of the Walla Walla to McNary and Hemingway to Captain Jack portions of the project being constructed. The CAC also evaluated the project as sized and designed in the project description portion above. Anything beyond that, such as double circuit or supersizing the project, is not being evaluated by NTTG. Our analysis is based on the current project size, design, and needs.

With this caveat, the Cost Allocation Committee's overall recommendation on the project is consistent with cost allocation principles.

Boardman – Hemingway

The project sponsor is Idaho Power Company. The project consists of a new, single-circuit 500-kV transmission line from the Boardman substation to the new Hemingway substation (to be constructed as part of Gateway West). The transmission line would span approximately 300 miles at an estimated cost of $600 million (2008 dollars). The expected in-service year is 2015.

Idaho Power states that the project would meet native/network customer obligations, but goes on to associate the project with PTP queue requests (which, by definition, are neither native or network load) totaling 1000 MW, or 71% of the project's potential 1400 MW east-to-west line rating. The estimated 1400 MW east-to-west line rating is dependent on completion of segments of Gateway West; without Gateway West this line rating would be limited to 800 MW.

Idaho Power anticipates that project investment will be rolled-in to existing capital investment used in existing FERC and state regulatory rate processes. It also states that it expects costs will be directly assigned to project users, in accordance with existing policies and rate designs.

Committee Action:

The project sponsor proposes proportional cost allocation for the network users of this line. Provided that an additional partner wishes to participate in this project and submits a separate cost allocation proposal to NTTG, the NTTG Cost Allocation Committee recommends approval of the cost allocation plan for this project.

Hemingway - Captain Jack

The project sponsor is PacifiCorp. The project is described as a new, single-circuit 500-kV line between the Hemingway substation (to be constructed as part of Gateway West) and Captain Jack. PacifiCorp provided no information as to project length, in-service date, specific need, capacity. It estimated the project cost, without AFUDC, at $931 million (nominal dollars).

Committee Action:

Although the construction of this project seems likely, the details of location, design, participants, and purposes are not complete enough at this time for the Cost Allocation Committee to make a recommendation. The Committee hopes that sufficient information will be forthcoming in time for incorporation into the final Cost Allocation Committee recommendation later this year.

Walla Walla - McNary

The project sponsor is PacifiCorp. The project is described as a new, single-circuit 230-kV line between the Walla Walla and McNary substations. PacifiCorp provided no information as to project length, in-service date, specific need, capacity. It estimated the project cost, without AFUDC, at $87 million (nominal dollars).

Committee Action:

Although the construction of this project seems likely, the details of location, design, participants, and purposes are not complete enough at this time for the Cost Allocation Committee to make a recommendation. The Committee hopes that sufficient information will be forthcoming in time for incorporation into the final Cost Allocation Committee recommendation later this year.

Southern Crossing

The project sponsor is Portland General Electric (PGE). The project consists of a new, single-circuit 500-kV transmission line running from the Coyote Springs substation to the Bethal substation, through intermediate substations at Boardman and Olallie. Total line miles are estimated at 215 miles at a cost of $610 million (direct costs, 2008 dollars).The estimated in-service date is 2015. The potential east-to-west project rating is 1400 MW (summer).

PGE states that the project is proposed to satisfy customer requests for network integration service and large generator interconnection requests by PGE Merchant. It expects that PGE Merchant will “cover the costs” of the project, although it is discussions with potential equity partners to become project participants.

Committee Action:

The Southern Crossing (SC) Transmission Project objectives are to integrate PGE’s Boardman and Coyote Springs thermal generation resources as well as up to 600 MW of additional renewables and thermal generation, while securing additional transmission capacity for the future. While the project sponsor generally proposes proportional cost allocation for the parties that wish to participate in the development of SC, large generation interconnection and network integration transmission service requests are key drivers.

The NTTG Cost Allocation Committee recommends approval of the cost allocation plan for this project provided PGE submits revised responses to individually address Principles 1 to 4 above by October 1, 2009.

Northern Tier Transmission Group

2008-2009 Cost Allocation

Draft Report: Appendices

High Voltage Transmission Towers March Across Utah

Appendix A: Data Request to Project Sponsors

May 28, 2009

Senior Vice President
Transmission
Company Name

RE: Name of Project(s)

Dear X:

The Northern Tier Transmission Group (NTTG) Cost Allocation Committee is urgently seeking information on your proposed transmission project(s) in order to complete our draft cost allocation recommendation on the NTTG Draft Biennial Plan by July 1, 2009. Although you may have previously provided responses to our requests for information, we are asking that you update that information to reflect current project status. In order to simplify the response process, we ask that you submit or re-submit detailed answers to the following items and in the following manner:

1. Proposed cost allocation

<u>You must propose a cost allocation scheme for the project. Otherwise, the Cost Allocation Committee will not make a recommendation.</u> Your proposal should address the following at a minimum: any interjurisdictional or other methodology used to assign costs to retail customers or to assign costs among transmission user groups. If you have integrated resource plans or other forecasts indicating future changes in project uses and/or cost allocations, please provide the results to the Committee.

2. Proposed cost recovery

Please indicate the applicable rate processes – federal, state, contractual, or other – needed to recover costs. Please include or refer to applicable ratemaking decisions already rendered or anticipated to be rendered because of a pending application or future application to be filed. If new or innovative rate processes or designs are anticipated, e.g., regional, multi-jurisdictional, incentive, project-specific, or negotiated rates, please describe. Please explain how these rate processes or designs will accommodate and reflect future changes in project use (e.g., formula rates).

3. A risk and benefit analysis focusing on the distribution of costs, benefits and risks among the parties proposed to share in the cost allocation of the project

Please provide any internal or third-party-prepared analysis for the project. This item should provide supporting documentation for the proposed cost allocation, including forecast future shifts in use. Some examples of benefits include improving reliability, serving existing retail load or anticipated retail load growth as indicated in your Integrated Resource Plan, fulfilling interconnection and transmission queue requests, accessing new or existing generation resources, and providing increased capacity for existing wholesale customers' load growth or other needs.

Please demonstrate the distribution of costs to beneficiaries. For example, are costs proposed to be directly proportionally distributed to beneficiaries on a load or energy or some other basis? With regard to risk, please indicate the level of risk for the project to be assumed by each beneficiary group and any proposals to mitigate risk. For example, differences in return on equity or its treatment for different customer groups constitutes a risk mitigation tool. The risk analysis will preferably provide the probability distribution assumed for benefits accruing to each party or class of party and include an explanation of how benefits were estimated. If benefits are foreseen for parties outside of the NTTG footprint, describe how costs and risks will be assigned to those parties.

4. How each NTTG cost allocation principle was applied in the analysis
You must provide your evaluation of how your project fits each principle in order to allow the Cost Allocation Committee to understand how you view the purpose(s) of the project.
For more information, you can access the Cost Allocation Committee Charter under "Charters & Agreements" and the Cost Allocation Principles under "FAQ" on the NTTG website, www.nttg.biz.

5. Additional project configuration options
As you know, some transmission projects included in the NTTG Draft Biennial Plan have the potential for alternative design/configuration. In fact, the discussion of right sizing or upsizing transmission projects is ongoing within NTTG and the Western Interconnection (and nationally). If you are considering an alternative size or configuration for your project, the Cost Allocation Committee needs to know what will drive the decision to upsize and what implications that decision will have for costs and cost allocations.

The best way to see the impact of alternatives is to segregate or bifurcate project costs and cost allocations as they relate to various project design/configuration alternatives. For example, if a project needs to be only single circuit, 345-kV to serve projected native load and wholesale transmission obligations and current queue requests, that portion of the project should be identified and the proposed cost allocation set forth accordingly. To the extent additional costs may be incurred to either increase voltage (e.g., designed, permitted, and constructed at 500-kV, while initially operated at 345-kV) or number of circuits, the reasons for incurring these additional costs should be described, along with the actual or potential future beneficiaries and proposed cost allocation of these additional costs. The decision process and decision timeline as to whether or not the project sponsor will proceed with the "upscaled" project alternative(s), versus the more limited project, should also be included.

This segregation of project costs and the rationale for potential "upscaling" will be important technical and qualitative information in the Cost Allocation Committee's review and recommendation as to cost allocation. In particular, absent your help, the Committee will not be well-suited to determining the cost differential, for example, between single, 345-kV line and a single circuit 345-kV line, built with towers capable of accommodating a 345-kV double-circuit configuration. Thus, we are requesting that you provide sufficient information on alternative configurations to indicate 1) the decision factors leading to the decision to implement the alternative, 2) any studies or process employed to support that decision, 3) the additional costs, benefits, and risks associated with the alternative, and 4) the additional capacity and other operational benefits associated with the alternatives.

6. Degree of consensus among stakeholders

Your response should indicate areas of agreement and disagreement among the stakeholders and should include supporting documentation. For example, a regulatory order can point to consensus or lack of it among stakeholders, or local or NTTG stakeholder processes or any other solicitation of public input can demonstrate the level of participation and consensus on the cost allocation for your project(s).

On May 26, 2009, the Cost Allocation Committee adopted the attached template table for reporting our draft recommendations to the NTTG stakeholder meeting in July. You may use the attached template to respond to the information requested above, with the caveat that you also provide any additional analysis requested. The Committee also requests that you provide the additional information requested in the template table.

The more thoroughly you can describe all of these items, the better the Cost Allocation Committee will be able to evaluate your project(s). The Committee requests that your responses be submitted via email by **June 5, 2009**. Please let me know if you cannot meet this deadline or have any questions.

Sincerely,

Lou Ann Westerfield, Chair
NTTG Cost Allocation Committee
Louann.Westerfield@puc.idaho.gov
(208) 334-0323

Attachment: CAC Recommendation Template

NTTG Cost Allocation Recommendation
Project Summary Template

Template Approved 05-26-09

Project Name: ***Project Lead:***	
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	
• WECC Rating Process – Phase	
• Status and estimated completion date of federal, state, and local permitting/siting processes	
Project sponsor(s):	
• Organization name(s)	
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	
• Decision factors for choosing alternative configuration options	
• Additional cost estimate for alternative configurations (marginal cost)	
• Potential increased capacity for alternative configurations	
Level of commitment:	
• Is there a committed Anchor Tenant?	
• What is the percent of contractual commitment from PTP customers	
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	
Cost allocation plan:	
• Sponsors proposed cost allocation plan	
• How project plans to recover cost	
• Contingency plan if initial cost recovery plan is not realized	
• Has the Project received, or does it intend to apply for FERC incentives?	
• Risk mitigation plan if market does not develop as expected	
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable	

to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	

Cost Allocation Recommendation:
Disclaimer: **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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.**

Appendix B: Project Templates

This appendix provides templates for each project that summarize its key physical characteristics, the need for and/or intended purpose(s), proposed cost allocation and recovery mechanism(s), and its adherence to NTTG's four Cost Allocation Principles

NOTE: The information provided in this appendix is dynamic and subject to change without additional notice. The information from the project sponsor regarding the project characteristics, status, and cost allocation/recovery is collected and provided here for convenience; specific data should be confirmed on the project sponsor's Web site or via processes posted on their respective OASIS systems.

Project 1: Hughes Transmission Project

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Hughes 230kV Transmission Project Darrel Zlomke, Wyoming Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Accommodation of forecasted network load growth as well as integrating the Dry Fork 390MW generation station
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	None
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Hughes-Dry Fork 230kV = 17 miles Dry Fork-Carr Draw 230kV = 23 miles Dry Fork-Sheridan 230kV = 103 miles
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	Project is under construction. In service date is November 2009
• WECC Rating Process – Phase	Just Initiated TOT4A/4B Rating Process
• Status and estimated completion date of federal, state, and local permitting/siting processes	All permits obtained
Project sponsor(s):	
• Organization name(s)	Basin Electric Power Cooperative
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	2009 WECC progress report
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$82.9 million Estimate came from September 2008 FERC rate filing.
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	None

• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No other active projects available to serve network load
• Decision factors for choosing alternative configuration options	
• Additional cost estimate for alternative configurations (marginal cost)	
• Potential increased capacity for alternative configurations	
Level of commitment:	
• Is there a committed Anchor Tenant?	Basin Electric network load
• What is the percent of contractual commitment from PTP customers	0%, project is for network load
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Included in FERC JOATT rates
• How project plans to recover cost	Through FERC tariff
• Contingency plan if initial cost recovery plan is not realized	NA
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Project developed for identified system needs, not market initiated.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Cost of project being born by network users and recovered through FERC approved tariff rates.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and	This project is needed for native load service for Basin's members. This project will facilitate future network load growth.

stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	Project costs are being allocated to the transmission customers through FERC-approved rates.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	This project would only incur Type 1 costs
Cost Allocation Recommendation: **The project is a multiple use project. Cost of the project will be recovered through FERC approved tariff; project is already under construction with in-service date of 4th Quarter 2009. The proposed cost allocation methodology is consistent with the NTTG cost allocation principles.**	

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

Project 2: Wyodak South Project

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Wyodak South 230 kV Darrell Zlomke, Wyoming Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Reliability, network load growth, Point-to-Point transmission requests
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	The project purpose has not changed
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	A 49 mile 230 kV line between Donkey Creek and Pumpkin Buttes substations and a 69 mile 230 kV line from Pumpkin Buttes to the DJ Area, both lines wholly located in Wyoming
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	Donkey Creek-Pumpkin Buttes: Construction Start: 3/2008 In-service: 4/2009 Pumpkin Buttes-DJ Area: Construction Start (est): 1/2010 In-service (est): 11/2010
• WECC Rating Process – Phase	N/A – Company states project is internal to its system, no negative impact to neighboring transmission providers
• Status and estimated completion date of federal, state, and local permitting/siting processes	Donkey Creek-Pumpkin Buttes: CPCN issued 1/7/2008 In-Service as of 4/3/2009 Pumpkin Buttes-DJ Area: CPCN to be filed (+/- 4-6 wks).
Project sponsor(s):	
• Organization name(s)	Black Hills Power
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	N/A
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	9/12/2007 – Wyoming PSC filing (Donkey Creek-Pumpkin Buttes) 9/29/2008 - FERC Rate Filing
Other project participant(s):	NA

Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$53 million as of 9/29/2008 per BHP Engineering department (also cost estimate provided in FERC filing) Estimate is in constant 2008 dollars
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Alternatives not contemplated as project is needed for transmission customer and network load growth uses
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Notified neighboring utilities of project and impacts upon completion of study work
• Decision factors for choosing alternative configuration options	NA
• Additional cost estimate for alternative configurations (marginal cost)	NA
• Potential increased capacity for alternative configurations	NA
Level of commitment:	
• Is there a committed Anchor Tenant?	N/A
• What is the percent of contractual commitment from PTP customers	< 10% to date
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Included in FERC JOATT rates (joint tariff of BH, Basin, & Powder River for 230-kV transmission over a Common Use System in area)
• How project plans to recover cost	Through FERC tariff
• Contingency plan if initial cost recovery plan is not realized	NA
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Project developed for identified system needs, not market initiated

Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Cost of project being born by network and point-to-point users.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	This project is needed for native load service, improved system reliability and point-to-point customer requests. This project will facilitate future network load growth and potential generation resources. This project was included in the most recent FERC rate fling which was accepted on 2/10/2009.
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the	Project costs are being allocated to the transmission customers through FERC-approved rates.

associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• **Principle 4** **For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.**	This project would only incur Type 1 costs.
Cost Allocation Recommendation: **This project is a multiple use project. Cost recovery for this project will be obtained thru a FERC approved OATT. Part of the project is already completed and in-service. The proposed cost allocation methodology is consistent with the NTTG cost allocation principles.**	
Disclaimer: **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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.**	

Project 3: Mountain States Transmission Intertie

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Mountain States Transmission Intertie (MSTI) Brian DeKiep, Montana Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Provide capacity to meet requests in transmission service queue from energy marketers, utilities and power generators and relieve constraints in the areas high voltage transmission system. Project is not needed as a network resource.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Not Applicable
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Approximately 430 mile 500KV AC line with 1500MW North to South, 950 South to North. Townsend Montana and terminating in Midpoint Idaho. Proposed Montana collector system to terminate and connect to MSTI at Townsend Montana substation.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	2013
• WECC Rating Process – Phase	Phase II
• Status and estimated completion date of federal, state, and local permitting/siting processes	Montana Major Facility Siting Act (MFSA) application filed July 2008. Final DEQ/BLM EIS expected in the Spring of 2010.
Project sponsor(s):	
• Organization name(s)	Northwestern Energy
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.msti500kv.com
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	April 1, 2009. Post Technical Conference Comments Errata EL09-29-000. Northwestern press release on June 23, 2009. FERC Declaratory order 127 FERC 61,266.
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$1,000,000,000 estimated construction cost as of March 31, 2009 for MSTI. Estimate does not include the collector system. Response to comments submitted to Northwestern on March 19, 2009 by CAC.
Additional project configuration options:	

• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Not Applicable
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Not Applicable
• Decision factors for choosing alternative configuration options	Not Applicable
• Additional cost estimate for alternative configurations (marginal cost)	Not Applicable
• Potential increased capacity for alternative configurations	Not Applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	Information not available until Open Season
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	No
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Northwestern Energy's proposal for subscribers to pay negotiated rates for service filed in January of 2009 was rejected by FERC on June 18, 2009. Northwestern Energy intends to move forward with MSTI as a traditional cost of service project and no longer a merchant transmission line.
• How project plans to recover cost	Cost recovery will be from transmission users. No cost recovery will be allocated to native load in Montana. Northwestern Energy intends to file for appropriate tariff waivers to isolate native load customers.
• Contingency plan if initial cost recovery plan is not realized	If open season does not materialize sufficient subscription the project will not move forward.
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Project size will be evaluated on open season subscription.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	MSTI satisfies Principle I. The subscribers to the line are the cost causers and will receive the benefits of transmission service.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS	

(Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub regional planning resources should be utilized and the results demonstrated.	
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	MSTI is proposed as a type 2 project. All costs will be directly recovered from transmission subscribers to the line and not Northwestern Energy's native load customers. Type 2 transmission costs are typically FERC jurisdiction and not subject to state review. However, due to the FERC order on June 18, 2009 there remains uncertainty surrounding Principle 4. Northwestern intends to file for the appropriate tariff waivers to isolate native load.

Cost Allocation Recommendation: **The Cost Allocation Committee will not be making a cost allocation recommendation on the MSTI project due to the uncertainty surrounding the FERC declaratory order on June 18, 2009. Northwestern's commitment to moving forward with MSTI as a traditional cost of service project has not been fully addressed by Northwestern Energy or the Cost Allocation Committee. The Cost Allocation Committee intends to re-evaluate the MSTI project once Northwestern Energy provides additional information.**
Disclaimer: **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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.**

Projects 4-12: Energy Gateway Project (including Projects 14 & 15 Hemingway-Captain Jack and Walla Walla-McNary)

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Energy Gateway, PacifiCorp Lou Ann Westerfield, Idaho Public Utilities Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The Energy Gateway project is a system-wide transmission expansion program originally announced by PacifiCorp in May 2007. The project will enable economic dispatch of the network resources, link PacifiCorp's east and west balancing areas, enhance accessibility to location-constrained renewable energy sources, reduce congestion in the transmission-constrained Western Interconnection, improve the reliability of the system, and help PacifiCorp to continue to provide reliable, cost-effective electric service to its customers.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	PacifiCorp received 39 transmission queue requests after announcing Energy Gateway in 2007. To honor these requests required the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). Two groups of customers were provided with contract offers in late 2008 and all customers chose to decline. PacifiCorp still believes there are short-term and long-term benefits for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp is proceeding with efforts regarding planning, rating, and permitting requirements for the Energy Gateway Program which facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need

	and construction timing. PacifiCorp is moving forward with the expansion plan that will construct transmission lines and substations required to provide 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	The Energy Gateway project is anticipated to add approximately 2,000 miles high voltage AC transmission lines traversing the states of Oregon, Idaho, Utah, Wyoming, Nevada and Colorado. The Walla Walla to McNary segment in Washington is part of the Energy Gateway project but not included in this, or earlier, data responses as it is currently under review as the optimal plan of service. Line voltages range from 230-kV to 500-kV with single and double-circuit segments.
• Estimated construction start date • Estimated in-service date **Note:** These dates are estimates only.	Construction began on the first segment of the Energy Gateway project, Populus to Terminal, in November 2008. This segment includes double-circuit 345-kV transmission lines that will run from a new Populus substation near Downey, Idaho approximately 135 miles south to the existing Terminal substation near the Salt Lake International Airport west of Salt Lake City, Utah. Estimated in-service date for this segment is December 2010. Gateway West segments are estimated to be in-service in 2014-2016 and 2014-2017 for Gateway South. These in-service date estimates are based on placing facilities in-service for the project that would result in 1,500 MW of capacity each for Gateway West and Gateway South segments.
• WECC Rating Process – Phase	Gateway West and Gateway South segments are in Phase II of the WECC Ratings Process. The Populus to Terminal segment of Gateway Central is in Phase III. The Hemingway to Captain Jack segment has completed the regional planning report process and anticipated to enter Phase I later this year.
• Status and estimated completion date of federal, state, and local permitting/siting processes	**Gateway West:** Third party environmental consultant, Tetratech, has been hired and is working with the Bureau of Land Management (BLM), and Federal, State and local agencies to complete the permitting process. The expected NEPA ROD (National

	Environmental Projection Act Record of Decision) is January 22, 2011. **Gateway South:** Third party environmental was consultant, EPG was hired and is working with the BLM and Federal, State, and local agencies to complete the permitting process. The estimated NEPA ROD based on the most recent BLM schedule is July 1, 2012. **Gateway Central**: The siting study efforts for the project were conducted in two phases. Convenience and Necessity approvals granted by Idaho and Utah. • Populus – Terminal: Convenience and Necessity approvals were granted by Idaho and Utah. Permits with two cities are pending and should be complete by July 2009. Army Corp of Engineers. NWP 12 pre-construction notice permit for a portion of the project is pending with the Army Corp of Engineers and is expected to be completed by July 2009. Environmental assessment required for a portion of the project was completed in May 2009. A federal special use permit will be required prior to the reconductor segment work in the Bear River Migratory Bird Refuge in January 2011. Migratory Bird Treaty act permits may be required for ground nests and are expected to be obtained by August 2009. All other federal and state permits required for construction have been obtained. Local construction permitting will be ongoing until construction is completed in November 2010 for the Populus Terminal segment and March 2011 for the reconductor segment. • Mona – Oquirrh: The draft EIS was issued May 15, 2009. A third party environmental consultant; EPG was hired and is working with the BLM and Federal, State, and local agencies to complete the permitting process. The estimated NEPA ROD based on the most recent BLM schedule is April 15, 2010. • Oquirrh – Terminal: Third-Party Environmental Consultant will be hired Q3 2009 to develop and implement permit strategy. There is no NEPA ROD required. The estimated completion for Federal,

	State, and local permits is September 15, 2009. **Hemingway-Captain Jack:** The siting and permitting work has not been initiated on this project.
Project sponsor(s):	
• Organization name(s)	PacifiCorp
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/Article/Article79554.html
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	May 27, 2009
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$6.0 Billion February, 2009 Internal systems
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	PacifiCorp has studied the Energy Gateway topology at double circuit 500-kV as required to meet early queue requests. Current topology, as required for long term load service and network resource delivery is single circuit 500-kV. The project capacity was doubled in an effort to respond to early queue requests.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	PacifiCorp has sought equity participants for 18 months to share in costs of an upsized project; however none have stepped forward with funding. PacifiCorp is currently coordinating with WAPA, other project sponsors originating in Wyoming, and the state of Wyoming on these issues including wind collector systems.
• Decision factors for choosing alternative configuration options	The existing configuration was validated as the optimum configuration through study, including joint efforts through the NTTG. Additional advantages to the Energy Gateway plan

	include it eliminates the need to request a second line and permitting exercise in the near term by building a large capacity line now, allows integration with the existing AC system to collect multiple resources and serve multiple load points throughout Wyoming, Idaho, Utah, and Oregon, and the planned topology provides contingency considerations for single line outages to minimize disruptions in load service caused by large line outages.
• Additional cost estimate for alternative configurations (marginal cost)	Doubling the 500-kV capacity would increase costs by at least $5 Billion.
• Potential increased capacity for alternative configurations	Double the planned 1500 MW per segment.
Level of commitment:	
• Is there a committed Anchor Tenant?	No.
• What is the percent of contractual commitment from PTP customers	None currently; customers declined offers in later 2008.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes. http://www.pacificorp.com/Navigation/Navigation23807.html
Cost allocation plan:	
• Sponsors proposed cost allocation plan	None, capacity is assigned for network service; therefore costs will be allocated to network customers and their retail customers.
• How project plans to recover cost	Staged rate cases as the project segments are placed into service.
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates.
• Has the Project received, or does it intend to apply for FERC incentives?	Yes.
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.

Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	See narrative to Question 4.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub regional planning resources should be utilized and the results demonstrated.	See narrative to Question 4.
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission	See narrative to Question 4.

owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	See narrative to Question 4.

Cost Allocation Recommendation:

The Committee recommends proportional cost allocation to network customers on the basis of meeting existing and projected service and reliability obligations. The Committee will review this recommendation if and when potential third-party users make sufficient commitments.

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

Projects 9-12: Gateway West (Idaho Power)

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Gateway West, Idaho Power (supplemental information to PacifiCorp submittal Lou Ann Westerfield, Idaho Public Utilities Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	In addition to PacifiCorp's information, the Gateway West project allows delivery of new resources and ability of Idaho Power to meet transmission service queue requests. This project will relieve congestion on multiple transmission paths including Bridger West, Borah West, West of Midpoint, and mitigate existing reliability limits by potentially reducing some reliance on remedial action schemes. This project would increase capability through Idaho by approximately 3,000 MW and by up to 3,000 MW through Wyoming (with other Energy Gateway projects in service).
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Idaho Power's Integrated Resource Plan (IRP) is currently being updated, which will identify a portion of native and network load requirements. Scalability and construction timing of various project segments may accommodate additional third party Point-to-Point (PTP) transmission service requests, however PTP customers' level of commitment and forecasted needs may vary.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Gateway West segments through Idaho are proposed as single circuit 500-kV AC, in addition to the broader description of the Energy Gateway projects. This allows construction phasing, in addition to meeting reliability separation for rating studies. Estimated total circuit length of Gateway West is approximately 1,000 miles (undergoing routing, siting, and permitting) from eastern Wyoming to southwestern Idaho.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates only.	2009 is the estimated construction start for some substations, with line segment construction beginning as early as 2012 (pending receipt of siting and permitting approvals). 2014-2016 estimated in-service, with segment construction sequencing allows and needs materialize.
• WECC Rating Process – Phase	Phase 2
• Status and estimated completion date of federal, state, and local permitting/siting	Idaho Power and Rocky Mountain Power continue to conduct additional public participation routing meetings

processes	to determine acceptable local alignments as requested, and for inclusion.
Project sponsor(s):	
• Organization name(s)	PacifiCorp and Idaho Power Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.idahopower.com/AboutUs/PlanningForFuture/ProjectNews/GatewayWest/default.cfm
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	May 2009
Other project participant(s):	PacifiCorp Idaho Power expects to retain import capacity for network/native load growth in addition to providing for any transmission service requests under their Open Access Transmission Tariff (OATT).
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• Idaho Power Company's share estimated at approximately $600 million. • Estimate prepared December 01, 2008. • Idaho Power Project Management – based upon preliminary scoping. Currently undergoing public routing process. These 2008 constant dollars may be subject to additional private Rights of Way costs pending final route selection (normal ROW and permits are included).
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	See PacifiCorp's discussions.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	
• Decision factors for choosing alternative configuration options	Transmission service requests under the OATT which could not be supplied by the proposed project, and are willing to pay the "higher of" FERC rate, or third party willing to fund and assume entire risk of alternative configuration.
• Additional cost estimate for alternative configurations (marginal cost)	
• Potential increased capacity for alternative configurations	

Level of commitment:	
• Is there a committed Anchor Tenant?	
• What is the percent of contractual commitment from PTP customers	Existing PTP queue requests total 1000 MW east-to-west for a portion of the length of the Gateway West project of the expected 1500 MW Idaho Power share (67%). Service agreements are not yet signed and are also depend upon the Boardman to Hemingway project.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	This project need has previously been part of Idaho Power's IRP analysis. Idaho Power's current IRP is not expected to be complete until late 2009. Idaho Power has active PTP service requests which require this project to provide service.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Based upon current transmission service queue requests and OATT obligations, Idaho Power anticipates including project costs in existing FERC and state regulatory rate processes. Given Idaho Power's existing FERC formulary rate design and state jurisdictional allocation processes, Idaho Power expects costs will be directly assigned to users of the project according to existing policies and jurisdictional rate design. As final costs are yet to be determined Transmission Service Agreements have not been finalized to determine how or if FERC's "higher of" rate design would be applied to this project under the OATT.
• How project plans to recover cost	Include Idaho Power's share of project costs in existing FERC and state rates.
• Contingency plan if initial cost recovery plan is not realized	Project is currently in the siting and permitting process. Construction will be timed to meet reliability and customer requests/needs. If needs or participants materially change, the project construction may be delayed to match timing or modified if cost recovery risks are unacceptable.
• Has the Project received, or does it intend to apply for FERC incentives?	See PacifiCorp's response. Idaho Power has not applied for FERC incentives at this time.
• Risk mitigation plan if market does not develop as expected	If needs or participants materially change, the project construction may be delayed to match timing or modified as required.

Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Idaho Power's native and network load requirement costs will be born by the retail and wholesale customers according to existing OATT provisions and state jurisdictional processes. Additional users are directly accommodated through tariff pricing and recovery.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	Transmission access to additional resources is evaluated as part of Idaho Power's IRP processes. Idaho Power's current 2009 IRP will be completed later in 2009. Idaho Power's local transmission planning and NTTG processes to satisfy needs consistent with portfolio and queue requests, in addition to FERC Order 890 Attachment K transmission planning requirements under the OATT, continue to include and evaluate this project. Preliminary economic dispatch simulations are being conducted by NTTG with inclusion of the NTTG proposed transmission projects. Results are still pending.
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i]	As proposed by including Idaho Power's share of the project costs in existing rates and revenue requirements at both the federal and state levels, the project is expected to achieve full recovery and regulatory treatment, but no more. 3a - As proposed, the project costs will be directly allocated to users under existing OATT tariff provisions and revenue requirements including credits and system usage passed through to state jurisdiction load ratio uses of the transmission system. 3b - This project is not based directly upon economic efficiencies to reduce market congestion, but primarily upon reliable network service obligations. Transmission service requestors are assigned costs based upon their requests for service under existing FERC pricing

the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	methodologies including higher-of and rolled in calculations. Contractual obligations via the resultant service agreements provide for cost recovery of the prorated share of the project costs over the term of service agreement preventing cost shifting. Existing WECC rating processes prevent the service request or project from doing harm to network reliability or existing regional commercial capabilities.
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	This project is directly related to providing increased service to Idaho Power's native and network customer loads and meeting PTP service requests. Any third-party usage or requests result in additional OATT revenues directly offsetting revenue requirements and/or an increase in System Peak Demand resulting in a decrease of the transmission rate to all customers. Based upon the requirements and drivers of this project independent of additional uses, any Type 2 project costs and uses will serve to reduce costs to all users to the extent capacity is available beyond the needs of native and network customer loads.

Cost Allocation Recommendation:

The Committee recommends the proposed proportional allocation to network customers on the basis of meeting existing and projected service and reliability obligations. The Committee will review this recommendation if and when potential third-party users make sufficient commitments.

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

Project 6 & 7: Energy Gateway Central

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Gateway Central/ Segment B – Populus to Terminal Joni Zenger, Utah Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Increase reliability and help to address network load growth and attract more renewable energy projects, part of MEHC merger commitment to upgrade Path C
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Will be incorporated in PacifiCorp's 2010 business plan and the PacifiCorp's 2008 IRP
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	135 mile double circuit 345 kV AC line crossing the southeast Idaho transmission system to the Wasatch Front
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	February 2009 December 2010 Construction began in November 2008.
• WECC Rating Process – Phase	Currently WECC Phase III
• Status and estimated completion date of federal, state, and local permitting/siting processes	Certificates of Public Convenience and Necessity – Utah PSC, September 2008; Idaho PUC, October 2008
Project sponsor(s) PacifiCorp	
• Organization name(s)	PacifiCorp, dba Rocky Mountain Power
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/Article/Article79647.html
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	May 2009, update provided by NTTG CAC; data request from PacifiCorp received on June 29, 2009
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	Approximately $800 million for segment B (initial application for CPCN); later revised to $750 million; (project cost EPC - $582 million, March 6, 2009, PacifiCorp Energy Gateway Update presentation) $815 million (data response June 29. 2009)
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Possible upsizing of project depending on the outcome of queue requests and obtaining third-party sponsors

• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Not applicable
• Decision factors for choosing alternative configuration options	
• Additional cost estimate for alternative configurations (marginal cost)	Not applicable
• Potential increased capacity for alternative configurations	Not applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	0%
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes. Included in PacifiCorp's 2008 IRP. http://www.pacificorp.com/Navigation/Navigation23807.html.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	None, capacity is assigned for network service; therefore costs will be allocated to network customers and their retail customers. Costs are allocated in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	Costs will be recovered through staged rate cases and/or other rate adjustment mechanisms as project segments are placed into service. Any wholesale sales will be recovered from transmission customers based on OATT rates.
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates,
• Has the Project received, or does it intend to apply for FERC incentives?	Applied for and has received FERC approved incentive rate treatment on October 21, 2008 (Docket No. EL08-75-000); FERC approved a 200 basis point incentive ROE adder to its base return on equity and recovery of prudently incurred abandonment costs if the project is cancelled due to factors beyond its control (with the exception of Segment A)
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should	Satisfies Principle 1: Cost of project is being borne by network and end users

be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	This project was identified in PacifiCorp's 2008 IRP with analysis results provided on May 29, 2009. The project was included in the preferred portfolio results. The IRP requires that all state RPS requirements are met and that the IRP must be consistent with other states in PacifiCorp's jurisdictional serving area. (The Utah Commission has not yet made a determination of acknowledgment of PacifiCorp's 2008 IRP.)
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	Project costs are being allocated to the transmission customers through FERC-approved rates. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines—the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the	Not a type 2 project; PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in

transmission owner should look to its transmission customers for direct recovery of costs.	the project

Cost Allocation Recommendation:

"For PacifiCorp the core purpose of the Energy Gateway is to serve network load requirements. However, the investments now known as Energy Gateway, meet multiple needs for PacifiCorp's network customers, including projects already in the Company's 10-year business plan to meet projected load growth, deliver planned network resources, reduce congestion, and improve system reliability. These additional investments are necessary to relieve transmission capacity shortage limiting delivery of new generation resources to network customers throughout PacifiCorp's service area." (June 13, 2009 data response).

According to PacifiCorp's FERC filing the additional transmission infrastructure and the "hub and spoke" design will provide flexibility, improve efficiency and enable development of clean and renewable energy resources and will ensure that PacifiCorp's system will be capable of meeting future regional needs. (PacifiCorp Petition at 8 and 9).

The Cost Allocation Committee is evaluating this project on a whole based solely on the project's stated need to meet network load obligation and growth of existing customers as well as to meet reliability needs. However, there may be a variety of drivers for the project as a whole, such as third party providers. Therefore, the CAC is not addressing these other drivers of the project. The Gateway project will be treated as a comprehensive interdependent effort to upgrade reliability and provide more access to resources on all sides of the system. The CAC has reservations due to the uncertainty of the Walla Walla to McNary and Hemingway to Captain Jack portions of the project being constructed. The CAC also evaluated the project as sized and designed in the project description portion above. Anything beyond that, such as double circuit or supersizing the project, is not being evaluated by NTTG. Our analysis is based on the current project size, design, and needs.

With this caveat, the Cost Allocation Committee's overall recommendation on the project is consistent with cost allocation principles.

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Gateway Central/Segment C – Mona to Oquirrh Joni Zenger, Utah Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Increase reliability and help to address network load growth, part of MEHC merger commitment to upgrade Path C
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Single circuit line included in PacifiCorp's 2008 IRP
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	100 mile double circuit 500/345 kV line crossing 4 counties in Utah, 34 miles of the project is on BLM land
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	2010-2012
• WECC Rating Process – Phase	Currently WECC Phase I study complete
• Status and estimated completion date of federal, state, and local permitting/siting processes	Summer 2009- Early 2010 (local permits and approvals) The draft EIS was issued May 15, 2009. A third-party environmental consultant, EPG, was hired and is working with the BLM and federal, state, and local agencies to complete the permitting process. The estimated NEPA ROD based on the most recent BLM schedule is April 15, 2010.
Project sponsor(s) PacifiCorp	
• Organization name(s)	PacifiCorp/Rocky Mountain Power
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/Article/Article77800.html
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	May 2009, update provided by NTTG CAC; data request from PacifiCorp received on June 29, 2009
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	Approximately $569 (data response June 29, 2009)

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Possible upsizing of project depending on obtaining third-party sponsors
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	
• Decision factors for choosing alternative configuration options	BLM Draft EIS findings; government conditional use permits, siting issues
• Additional cost estimate for alternative configurations (marginal cost)	
• Potential increased capacity for alternative configurations	Upsizing project from 345 kV to 500 kV depending on outcome of queue requests and obtaining third-party sponsors
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	PacifiCorp posted the Energy Gateway project on its OASIS and has received significant interests in commercial point-to-point requests
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes. Included in PacifiCorp's 2008 IRP. http://www.pacificorp.com/Navigation/Navigation23807.html.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	None, capacity is assigned for network service; therefore costs will be allocated to network customers and their retail customers. Costs are allocated in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	Costs will be recovered through staged rate cases and/or other rate adjustment mechanisms as project segments are placed into service. Any wholesale sales will be recovered from transmission customers based on OATT rates..
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates,
• Has the Project received, or does it intend to apply for FERC incentives?	Applied for and has received FERC approved incentive rate treatment on October 21, 2008 (Docket No. EL08-75-000); FERC approved a 200 basis point incentive ROE adder to its base return on equity and recovery of prudently incurred abandonment costs if the project is cancelled due to factors beyond its control (with the

	exception of Segment A)
• Risk mitigation plan if market does not develop as expected	PacifiCorp conducted a risk and benefit analysis None. Capacity is required for load service.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Satisfies Principle 1: Cost of project is being borne by network and end users.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	This project was identified in PacifiCorp's 2008 IRP with analysis results provided on May 29, 2009. The project was included in the preferred portfolio results. The IRP requires that all state RPS requirements are met and that the IRP must be consistent with other states in PacifiCorp's jurisdictional serving area. (The Utah Commission has not yet made a determination of acknowledgment of PacifiCorp's 2008 IRP.)
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission	Project costs are being allocated to the transmission customers through FERC-approved rates. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines—the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.

owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	Not a type 2 project; PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in the project

Cost Allocation Recommendation:

"For PacifiCorp the core purpose of the Energy Gateway is to serve network load requirements. However, the investments now known as Energy Gateway, meet multiple needs for PacifiCorp's network customers, including projects already in the Company's 10-year business plan to meet projected load growth, deliver planned network resources, reduce congestion, and improve system reliability. These additional investments are necessary to relieve transmission capacity shortage limiting delivery of new generation resources to network customers throughout PacifiCorp's service area." (June 13, 2009 data response).

According to PacifiCorp's FERC filing the additional transmission infrastructure and the "hub and spoke" design will provide flexibility, improve efficiency and enable development of clean and renewable energy resources and will ensure that PacifiCorp's system will be capable of meeting future regional needs. (PacifiCorp Petition at 8 and 9).

The Cost Allocation Committee is evaluating this project on a whole based solely on the project's stated need to meet network load obligation and growth of existing customers as well as to meet reliability needs. However, there may be a variety of drivers for the project as a whole, such as third party providers. Therefore, the CAC is not addressing these other drivers of the project. The Gateway project will be treated as a comprehensive interdependent effort to upgrade reliability and provide more access to resources on all sides of the system. The CAC has reservations due to the uncertainty of the Walla Walla to McNary and Hemingway to Captain Jack portions of the project being constructed. The CAC also evaluated the project as sized and designed in the project description portion above. Anything beyond that, such as double circuit or supersizing the project, is not being evaluated by NTTG. Our analysis is based on the current project size, design, and needs.

With this caveat, the Cost Allocation Committee's overall recommendation on the project is consistent with cost allocation principles.

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

Project 13: Boardman – Hemingway

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Boardman-Hemingway 500 kV (B2H) Matt Muldoon, Oregon Public Utility Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Delivery of new resources and transmission service queue requests, relieve congestion on the ID-NW path, and mitigate existing reliability limits. This project would increase import capability from the Northwest into Idaho by approximately 850 MW and export capabilities would increase by approximately 800 MW (with Gateway West in service). The project is undergoing independent WECC rating with expected ratings of 1300 MW west-to-east and 800 MW east-to-west (1400 MW with the Gateway West project in service providing additional source capabilities removing constraints near Midpoint)
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Purpose and need remain the same. Additional equity partners' needs are expected to align with their participation level.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	500 kV AC, estimated length approximately 300 miles (undergoing routing, siting, and permitting) from southwest Idaho to northeast Oregon
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	2013 estimated construction start 2015 estimated in-service
• WECC Rating Process – Phase	Phase 2
• Status and estimated completion date of federal, state, and local permitting/siting processes	NEPA and Oregon siting public processes initiated. Currently Idaho Power is conducting additional public participation routing meetings to determine an acceptable alignment. This public process is expected to be complete late 2009 to allow environmental and other siting work to restart in 2010.
Project sponsor(s):	
• Organization name(s)	Idaho Power Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.boardmantohemingway.com/
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	5/7/09 NTTG CAC update by Idaho Power (prior NTTG CAC submittal on 10/3/08)

Other project participant(s):	Idaho Power is exploring participation with Portland General Electric, PacifiCorp, BPA, Avista, and other developers pending proposed routing and timing. It is expected participants' ownership interest will align rights with needs. Idaho Power expects to retain import capacity for network/native load growth in addition to providing for any transmission service requests under their OATT.
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$600 million 12/01/08 Idaho Power Project Management – based upon preliminary scoping and estimated length of 300 miles. Currently undergoing public routing process.
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Conductor selection allows for latent capacity beyond the initial WECC rating study results for the single circuit configuration. With future projects on separate corridors in the region, the 1300 MW west-to-east and 800 MW east-to-west (1400 MW with the Gateway West project in service providing additional source capabilities removing constraints near Midpoint) expected ratings of the proposed configuration may be increased to nearer the 3000+ MW thermal capabilities of the line. Lower voltages or smaller conductors will not meet the currently defined needs of the project. Increasing voltage or addition of another circuit would not be able to achieve any additional capacity through the WECC rating process and reliability criteria as this element is the single critical outage. Additional constraints on the West of McNary (WOM) cutplane would likely require additional projects to deliver additional power into northeastern Oregon. Therefore efforts to up-size this project are unwarranted and not cost effective at this time.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No other projects are being proposed through this corridor. However, projects in northeastern Oregon are coordinating study and siting efforts to allow development of a North East Oregon (NEO) substation to interconnect proposed projects. Technical studies are also being coordinated through the TCWG efforts. Portland General and Idaho Power are coordinating the Southern Crossing and B2H in the Boardman area to minimize circuits and line construction, while integrating multiple project needs. The Hemingway-Captain Jack project (PacifiCorp) has not begun siting, but has a different termination in Oregon and would only consider common corridor with appropriate separation until the B2H project proceeds

	northwestwardly toward Boardman substation.
• Decision factors for choosing alternative configuration options	Transmission service requests under the OATT which could not be supplied by the proposed project, and are willing to pay the "higher of" FERC rate, or third party willing to fund and assume entire risk of alternative configuration
• Additional cost estimate for alternative configurations (marginal cost)	Double circuit configuration could cost approximately an additional $350 million, and until other major projects reinforce the region, would produce no additional capacity or benefits
• Potential increased capacity for alternative configurations	Until/unless additional projects reinforce the region, there is no expected incremental capacity beyond the current project's expected WECC rating
Level of commitment:	
• Is there a committed Anchor Tenant?	Idaho Power transmission to meet native/network customer obligations. Other potential partners are exploring future capacity requirements and options.
• What is the percent of contractual commitment from PTP customers	Existing PTP queue requests total 1000 MW east-to-west of the expected 1400 MW rating (71%). Service agreements are not yet signed and are also depend upon some Gateway West segments.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	This project has been included in Idaho Power's IRP analysis updates as provided to the Oregon PUC in 2009. Idaho Power's current IRP is not expected to be complete until late 2009. Idaho Power has active PTP service requests which require this project to provide service.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Based upon current transmission service queue requests and OATT obligations, Idaho Power anticipates including project costs in existing FERC and state regulatory rate processes as rolled-in capital investments. Potential equity partners' share of rights, capacity, and costs are under discussion and not public at this time. Given the existing FERC formulary rate design and state jurisdictional allocation processes, Idaho Power expects costs will be directly assigned to users of the project according to existing policies and jurisdictional rate design. As information regarding other participants' information becomes publicly available, updates will be provided.
• How project plans to recover cost	Include Idaho Power's share of project costs in existing FERC and state rates

• Contingency plan if initial cost recovery plan is not realized	Project is currently in the siting and permitting process. Prior to commencing construction, capacity rights and equity participation will be established through construction agreements. If needs or participants materially change, the project construction may be delayed to match timing or cancelled if cost recovery risks are unacceptable.
• Has the Project received, or does it intend to apply for FERC incentives?	Not at this time
• Risk mitigation plan if market does not develop as expected	If needs or participants materially change, the project construction may be delayed to match timing or cancelled.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Idaho Power's native and network load requirement costs will be born by the retail and wholesale customers according to existing OATT provisions and state jurisdictional processes. Additional users are directly accommodated through tariff pricing and recovery.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	This project was identified in Idaho Power's IRP processes, with the most recent analysis provided under the February 2009 IRP Addendum and NTTG processes to satisfy needs consistent with portfolio and queue requests, in addition to FERC Order 890 Attachment K transmission planning requirements. Idaho Power's current 2009 IRP will be completed later in 2009. Preliminary economic dispatch simulations are being conducted by NTTG with inclusion of the NTTG proposed transmission projects. Results are still pending.

<table>
<tr><td>• <u>Principle 3</u>
Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more.
• <u>Principle 3a</u>
Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits.
• <u>Principle 3b</u>
Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.</td><td>As proposed by rolling in Idaho Power's share of the project costs to existing rates and revenue requirements at both the federal and state levels, the project is expected to achieve full recovery and regulatory treatment, but no more.

As proposed, the project costs will be directly allocated to users under existing OATT tariff provisions and revenue requirements including credits and system usage passed through to state jurisdiction load ratio uses of the transmission system.

This project is not based directly upon economic efficiencies to reduce market congestion, but primarily upon reliable network service obligations. Transmission service requestors are assigned costs based upon their requests for service under existing FERC pricing methodologies including higher-of and rolled in calculations. Contractual obligations via the resultant service agreements provide for cost recovery of the prorated share of the project costs over the term of service agreement preventing cost shifting. Existing WECC rating processes prevent the service request or project from doing harm to network reliability or existing regional commercial capabilities.</td></tr>
<tr><td>• <u>Principle 4</u>
For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.</td><td>This project is directly related to providing increased service to Idaho Power's native and network customer loads. Any third-party usage or requests result in additional OATT revenues directly offsetting revenue requirements and/or an increase in System Peak Demand resulting in a decrease of the transmission rate to all customers. Based upon the requirements and drivers of this project independent of additional uses, any Type 2 project costs and uses will serve to reduce costs to all users to the extent capacity is available beyond the needs of native and network customer loads.</td></tr>
<tr><td colspan="2">Cost Allocation Recommendation:
The project sponsor proposes proportional cost allocation for the network users of this line. Provided that an additional partner wishes to participate in this project and submits a separate cost allocation proposal to NTTG, the NTTG Cost Allocation Committee recommends approval of the cost allocation plan for this project.</td></tr>
</table>

Disclaimer:

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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.

Project 16: Southern Crossing

NTTG Cost Allocation Draft Recommendation As of July 1, 2009	
Project Name: ***Project Lead:***	Southern Crossing Matt Muldoon, Oregon Public Utility Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The proposed project is a new single-circuit 500 kV transmission line that would connect the southern portion of PGE's service territory near Salem, Oregon, to our Boardman and Coyote Springs plants near Boardman, Oregon. PGE anticipates the Project will provide access to firm transmission service for new renewable resources, which are planned to interconnect to this Project. Furthermore, the Project is expected to provide firm transmission service for PGE's Boardman and Coyote Springs generating plants, while at the same time improving reliability of both plants by providing an additional transmission circuit on which to transmit energy.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Purpose and need remains the same. Any additional equity partners that surface will need to recognize the intended purpose.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	500 kV AC, estimated length approximately 200 miles from Boardman OR to Salem OR.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	2013 estimated construction to start 2015 estimated in-service
• WECC Rating Process – Phase	WECC Phase I – 30 day review and comment period of re-submitted Comprehensive Progress Report.
• Status and estimated completion date of federal, state, and local permitting/siting processes	Currently preparing for NOI for State of Oregon EFSC & the Federal NEPA processes. Estimated completion December 2012
Project sponsor(s):	
• Organization name(s)	Portland General Electric Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	NA. Updates provided are at PGE OASIS (http://www.oatioasis.com/pge/index.html) and there are write-ups of TCWG activities and mailing lists maintained at the NWPP site (http://www.nwpp.org/).
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	WECC Comprehensive Progress Report re-submitted June 30, 2009 for 30 day review.

Other project participant(s):	PGE is the sole participant in the Southern Crossing project at this time. PGE and Idaho Power signed an MOU to work cooperatively on transmission development in the Boardman, OR area. PGE is in discussions with other potential participants at this time but cannot reveal specifics due to confidentiality considerations.
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	$610 million (2008 $, direct costs) December 2008 Portland General Electric, Transmission Planning
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	The conductor selection will allow for additional thermal capacity beyond the initial WECC study results for the proposed single circuit 500 kV configuration. Any voltages lower than 500 kV or smaller conductors would not meet the project rating objectives and would result in unacceptable line losses. Higher voltages, e.g., 765 kV, would not be practical or cost effective for a single circuit embedded in a predominantly 500 kV PNW grid. The potential for an additional circuit is being explored. This will be driven by the interests of other potential project participants and the efficacy of permitting a double circuit today instead of revisiting the permitting process in the future.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No other projects are currently proposed to add capacity to the West of Cascades South path. However, PGE is coordinating its study efforts with other project sponsors in the TCWG (Transmission Coordination Work Group). Also, the Southern Crossing project is proposed to be routed next to existing transmission lines to minimize the need for new transmission corridors and mitigate environmental impacts. System studies to-date have verified that NERC/WECC reliability criteria can be met with this approach. PGE and Idaho Power have coordinated efforts in the Boardman area to minimize circuits and line construction.
• Decision factors for choosing alternative configuration options	• Transmission Service Requests under the OATT which could not be supplied by the proposed project. • Permitting process identifies critical issues. • If an interested party is willing to fund and assume the risk of alternative configuration.

	• Design to accommodate anticipated future needs
• Additional cost estimate for alternative configurations (marginal cost)	Building a double circuit option for Southern Crossing but only stringing conductors for the first circuit would add approximately $160 million in direct capital cost.
• Potential increased capacity for alternative configurations	There may be some incremental capacity identified in the WECC Phase 2 studies as the interaction with other proposed projects in the region is studied. A double circuit configuration will not be studied at this time unless additional capacity needs are identified.
Level of commitment:	
• Is there a committed Anchor Tenant?	Not at this time. Network Integration Transmission Service (NITS) and Large Generation Interconnection (LGI) requests submitted by Portland General Electric Merchant initiated this project.
• What is the percent of contractual commitment from PTP customers	0% At this time there are no PTP customers.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	The Southern Crossing project will be included in PGE's 2009 IRP which will be filed with the Oregon PUC in the summer of 2009. PGE has active service requests in its OATT transmission queue which require this project to provide service.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Based on PGE's current transmission service requests and OATT requirements, PGE Merchant is expected to execute an LGIA and cover the costs of the Southern Crossing project. Potential equity partners' share of rights, capacity, and costs are under discussion and are confidential and proprietary at this time. Updates will be provided as other participants' information becomes publicly available.
• How project plans to recover cost	Costs will be recovered through appropriate FERC and OPUC rate base tariff provisions.
• Contingency plan if initial cost recovery plan is not realized	Southern Crossing is currently in the siting and permitting stage. Prior to making commitments for the detailed engineering, procurement and construction phase, all equity participation, capacity rights, and cost allocation agreements must be in place. Also, regulatory tariff and associated cost recovery requirements are expected to be defined. In the absence of these requirements, the project may be delayed or canceled if the financial risks are deemed unacceptable.
• Has the Project received, or does it intend to apply for FERC incentives?	The project has not received any FERC incentives at this time. However, PGE will consider making a filing to FERC for incentives once the project is more fully defined.

• Risk mitigation plan if market does not develop as expected	PGE continually monitors market factors to evaluate risks and the prudence of continuing with the project. PGE's project planning and structuring builds in checkpoints and off-ramps in the event market factors are not conducive to proceeding. In that event, the project could be delayed, re-configured, or canceled.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	NA. This is a customer-driven project (NITS & LGI requests). This project is not being undertaken as part of PGE's Attachment K process.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	NA. This is a customer-driven project (NITS & LGI requests). This project is not being undertaken as part of PGE's Attachment K process.
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed	NA. This is a customer-driven project (NITS & LGI requests). This project is not being undertaken as part of PGE's Attachment K process.

on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	NA. This is a customer-driven project (NITS & LGI requests). This project is not being undertaken as part of PGE's Attachment K process.
Cost Allocation Recommendation: **The Southern Crossing (SC) Transmission Project objectives are to integrate PGE's Boardman and Coyote Springs thermal generation resources as well as up to 600 MW of additional renewables and thermal generation, while securing additional transmission capacity for the future. While the project sponsor generally proposes proportional cost allocation for the parties that wish to participate in the development of SC, large generation interconnection and network integration transmission service requests are key drivers.** **The NTTG Cost Allocation Committee recommends approval of the cost allocation plan for this project provided PGE submits revised responses to individually address Principles 1 to 4 above by October 1, 2009.**	
Disclaimer: **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 Draft Transmission Plan per the Cost Allocation charter. This 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 will not be 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 recommendations shall not be framed as decisions 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.**	