NORTHERN TIER
TRANSMISSION GROUP

NTTG TECHNICAL WORK GROUP

2014-2015 BIENNIAL CYCLE

REVISED COST ALLOCATION STUDY PLAN

June 3, 2015

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I. Introduction

The Cost Allocation Committee may allocate the costs of projects the Planning Committee selects into the Draft Final Regional Transmission Plan (DFRTP) for purposes of cost allocation. The purpose of this study plan is to lay out the process whereby the NTTG Technical Work Group (TWG) will use the Draft Final Regional Transmission Plan to develop and analyze cost allocation scenarios. This analysis will determine the benefits of the DFRTP and the four allocation scenarios. Costs will be allocated if the benefits outweigh the costs of the project.

II. Draft Final Regional Transmission Plan

Through the study work conducted in quarters one through six of NTTG's Biennial Transmission Plan cycle, two non-committed projects were selected into the DFRTP along with the Committed Projects that were rolled up from the Transmission Providers' Local Transmission Plans. The first project, the Boardman to Hemingway (B2H) project, is a Sponsored Project and the sponsor did not request cost allocation consideration.

The second project selected in the DFRTP is an Alternative Project that was identified by the Planning Committee's TWG in quarter six. The Alternative Project consists of one new 230 kV transmission line from the Windstar substation in central Wyoming to Aeolus substation in southern Wyoming, two 500 kV transmission lines one from Aeolus to Populus substation in southeast Idaho and the second from Aeolus to Clover, a new substation near Mona, Utah. Also, parts of this project are re-enforcements to existing facilities to integrate the above line additions. Since this Alternative Project is an unsponsored project that was selected into the DFRTP, it is automatically eligible for consideration in NTTG's regional cost allocation process.

III. Cost Allocation Change Case

The DFRTP is the basis for creating the cost allocation scenarios. The Change Case will be the DFRTP compared to the Initial Regional Transmission Plan (IRTP), as adjusted for updated Quarter 5 loads and resources. The cost allocation scenarios will also be compared to the IRTP.

IV. Cost Allocation Scenario Cases

The DFRTP will be the basis for creating the four cost allocation scenarios. These scenarios will each be derived from the 2024 summer peak case that includes the two non-committed projects that were selected into the DFRTP.

The following cost allocation scenarios were requested by the Cost Allocation Committee (in consultation with the Planning Committee) and with stakeholder input. The cost allocation scenarios approved by the Cost Allocation Committee on April 29, 2015 are listed below.

Load Allocation Scenarios:

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

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

Resource Location/Type Allocation Scenarios:

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

D. Take out 1,000 MW of coal and presume units that are not retired in the 2024 case can be reduced pro rata and replaced with equivalent amount of energy in equal shares of wind and solar in the appropriate geographic locations (e.g. wind in WY and MT and solar in ID and UT).

See Appendix A for additional detail on the cost allocation scenarios that were approved by the Cost Allocation Committee on April 29, 2015.

V. Power Flow Analysis

The DFRTP, Change Case and each of the cost allocation scenarios will be analyzed using power flow analysis. The analysis will be an N-0 power flow study to create a solved N-0 case that may include thermal or voltage reliability issues. If mitigation is required to meet reliability criteria, these will be identified, including an estimate of the capital cost for the mitigation.

VI. Benefits and Beneficiary Analysis

Three economic metrics are defined below. These metrics are: A) capital costs, B) line losses, and C) reserve margin. Each criterion (A), (B), and (C) will be expressed as an annual change in costs (or revenue) and provided to the Cost Allocation Committee. A common year will be selected for net present value calculations for all cases to enable a comparative analysis between each Change Case and the Initial Regional Plan, as adjusted for updated Quarter 5 load and resource data. The following describes the metric and calculation of its benefit.

A) Capital Cost Benefit - The capital cost benefit will be computed from the annual capital-related costs[1] for each Transmission Provider. The difference between the Change Case capital cost and the DFRTP (or a cost allocation scenario) capital cost computes the benefit related Alternative Project in the DFRTP (or a cost allocation scenario). This difference will provide the capital cost benefit. The beneficiaries are the Transmission Providers.

B) Line Loss Benefit - The line loss benefit is computed as a change in energy generated to serve a given amount of load. The change in energy loss between the change case and the DFRTP (or a cost allocation scenario) measures the line loss impact benefit of the Alternative Project in the DFRTP (or a cost allocation scenario). The line loss will be computed through power flow analysis and monetized using an index price of power for each Transmission Provider. Again the beneficiaries are the Transmission Providers.

C) Reserve Margin Benefit - This metric is based on savings that may result when two or more Balancing Authority Areas could economically share a reserve resource when unused transmission capacity remains in transmission project. The reserve margin metric will be computed through spreadsheet analysis and monetized using an index price of power for each Balancing Authority Area and measures the benefit of the Alternative Project in the DFRTP (or a cost allocation scenario). The beneficiaries are the Balancing Authority Areas.

VII. Cost Allocation Committee

The TWG will provide the benefit information calculated above to the Cost Allocation Committee to be used in the cost allocation process.

[1] Annual capital-related costs will be the sum of annual return (both debt and equity related), depreciation, taxes other than income, operation and maintenance expense, and income taxes.

Appendix A[2]

Load Change Case Allocation Scenarios:

2024 PCM Data				2012 Actual + 2013 Actual + 2024 PCM Weights		
	MW					
	Actual 2012	Actual 2013	PCM 2024	Weight	Low Scn -1000	High Scn 1000
IPC	3,587	3407	4,013	16.7%	3,846	4,180
NWE	1,785	1707	1,855	8.1%	1,774	1,936
PACE	6,763	8989	9,798	38.7%	9,411	10,185
PACW	3,708	4354	4,083	18.4%	3,899	4,267
PGE	3,642	3900	4,426	18.1%	4,245	4,607
NTTG	19,485	22,357	24,175	100.0%	23,175	25,175

Replace 800 MW Wind with 800 MW Solar

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

[2] Source is the Dec 18, 2014 NTTG Stakeholder Presentation

2024 PCM Data

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

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

** Accounts for coal retirements.

Energy in aMW

a	b	c	d	e	f	g	h	i	j
				Energy Change as a Result of 1000 MW Coal Lost			ADJUSTED aMW		
	Coal **	Solar	Wind	Coal	Solar *	Wind *	Coal	Solar *	Wind *
IPFE	0	0	22	0	97	0	0	97	22
IPMV	0	0	63	0	97	0	0	97	63
IPTV	0	0	98	0	97	0	0	97	98
NWMT	2,164	0	221	-191	0	51	1,973	0	272
PACW	0	0	177	0	0	137	0	0	315
PAID	0	0	59	0	0	0	0	0	59
PAUT	3,357	107	0	-296	97	0	3,061	204	0
PAWY	3,234	0	455	-285	0	166	2,949	0	621
PGE	0	0	0	0	0	0	0	0	0
Total	8,756	108	1,095	-772	386	354	7,983	494	1,449

** Accounts for coal retirements.

Capacity Factor

a	b	c	d
	Coal **	Solar	Wind
IPFE	0%	0%	28%
IPMV	0%	0%	28%
IPTV	0%	0%	27%
NWMT	81%	0%	35%
PACW	0%	0%	28%
PAID	0%	0%	28%
PAUT	70%	23%	0%
PAWY	83%	0%	34%
PGE	0%	23%	0%
Total	77%	23%	32%