BPA 2008 Network Open Season

Congestion and Production Cost Analysis

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January, 2009

Forward

This report was prepared by Comprehensive Power Solutions, LLC, under contract to the Bonneville Power Administration. The work is based on an extensive effort by the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC) to collect and develop data that allow simulation of hourly operation of the Western Interconnection's transmission grid and generating resources. Engineers and analysts at the Bonneville Power Administration have also provided essential information and direction to this project.

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Executive Summary

This study was conducted to identify certain Northwest regional economic benefits and effects of adding generation identified by the Bonneville Power Administration's 2008 Network Open Season (NOS), and associated system transmission expansion.

Based on reduced hours of congestion across BPA flowgates, increased operations and maintenance (O&M) flexibility resulting from new transmission, and facilitation of further renewable generation additions to meet state Renewable Portfolio Standards (RPS), this analysis indicates that, of the transmission projects studied in this project, significant congestion benefits were realized with the proposed West of McNary (McNary – John Day, Big Eddy – Station Z), I-5 Corridor, and Little Goose reinforcements.

Future NOS studies (clustering studies and economic analyses) should consider:

- the timing for imposition of a cost on carbon dioxide emissions and how that cost is reflected in energy prices, choice of fuel, and selection of resources,
- how the regional location of new renewable resources may affect transmission planning,
- at what level and location of renewable additions is the hydroelectric system's existing redispatch capability exceeded, causing significantly higher redispatch costs,
- the effects of "smart grid" infrastructure and transportation on transmission planning policies and technologies.

Scope

The benefits and effects to be identified include:

- Is there a reduction in future variable costs or production (fuel and variable O&M) resulting from system operational changes with the addition of all NOS generation?
- What is the effect on BPA's internal flowgate loadings with the NOS generation additions (frequency of certain path loading levels)?
- Is there a reduction in production costs and internal flowgate loadings due to the addition of new transmission facilities?
- What impacts on generation dispatch and path loadings result from carbon dioxide costs?

Assumptions

- Precedent Transmission Service Agreements (PTSAs) not associated with a new generator were assumed to be from generators already in service.
- The analysis models the Western Interconnection as a 'single-owner' system.
- Variable costs for wind-powered electricity are assumed to be negligible, and dispatch considerations in the model and analysis do not encompass the need by generators to recover their capital costs, fixed O&M costs, production tax credits and so on, in their power prices.
- Path loadings were considered high if there were hours at or above 75% of the path's limit
    - The analysis assumes all lines and voltage support are in service at all times

  - Under outage conditions which change flows and reduce flowgate limits, variable production costs are expected to increase significantly and the flexibility of hydrogeneration redispatch is expected to be diminished.
- The study assumes a 2002 hydro condition (near median), expected loads, and typical wind.

Observations

- The NOS generation additions are accommodated without significant operational difficulties (though with increased transmission congestion) and with substantial production cost savings.
- Approximately $8-$10 million in annual variable production costs of fossil-fueled generation are realized
  - Reduced overall fossil fuel utilization and increased use of lower-cost thermal plants
  - Savings should have some stability across future years, though increasing costs to integrate incremental wind may not be offset by incremental fossil fuel cost savings
- Congestion on BPA's network flowgates increases with the new generation, requiring redispatch (primarily of hydrogeneration, also of thermal generation), but is mitigated by the proposed transmission reinforcements
  - Proposed reinforcements would reduce congestion during transmission system outages, maintenance outages, and congestion due to additional renewable generation.
  - Proposed reinforcements would facilitate integration of most NOS generation, which is located near main grid transmission and major hydrogeneration.

With respect to all of these observations, it may be assumed that the production cost benefits and hours of reduced congestion attributable to transmission reinforcements would increase significantly under periods of prolonged transmission outage or maintenance.

Conclusions

- The energy produced by the new generators will displace high-cost generation, much of which is located outside the Northwest. This makes it difficult to measure net economic impacts in the Northwest, particularly when renewable energy credits are considered.
- Including NOS generation, renewable resources make up approximately 5.3% of total energy served in Oregon and Washington.
  - Proposed reinforcements will facilitate delivery of additional renewable generation to Northwest customers.
  - Absent reinforcements, the addition of renewable resources results in increased loadings (and so congestion) on several Northwest paths.

Study Purpose, Scope and Outline

Economic Analysis of the BPA 2008 Network Open Season

The Bonneville Power Administration's 2008 Network Open Season, more fully described elsewhere, is an extensive process that, among other things, is designed to sufficiently define and assess impacts of potential generation additions on transmission loading and of congestion-induced increases in costs for electricity.

This component of BPA's analysis is focused on measurement of the amounts of congestion and the resulting changes in power plant variable costs due to different combinations of generation additions and transmission grid modifications. The combinations of generation and transmission studied are derived from the Network Open Season Cluster Study.

Objectives and Focus

This report analyses the impacts of new generation proposing to connect to the BPA transmission system by focusing on two measures that may be extracted from an hourly security-constrained production cost simulation.

The first is the degree of congestion on defined transmission paths, as measured by the number of hours during the sample year that flows on the paths exceeded various percentages of their transfer limits. As the number of hours increases at a given level, the potential curtailment of generation or risk of unserved load also increase.

When lower-cost generation cannot reach higher-value load over a specific path, the power must either find its way over a higher-loss (and so higher-cost) alternate route, be replaced by a higher-cost resource closer (in terms of losses) to the load, or the power needed doesn't reach the load and the demand goes unserved.

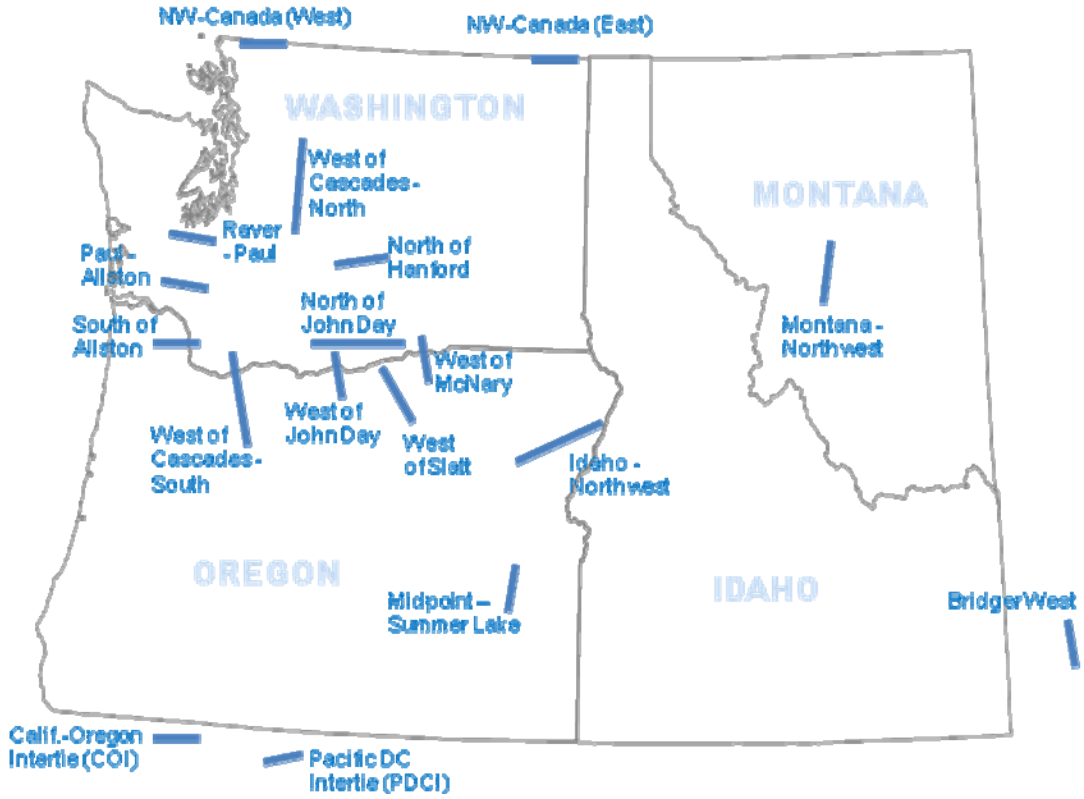
The second measure is to determine the cost implications of congestion, by recording the amount of unserved load, if any, and accumulating the total fuel and variable operations and maintenance cost (variable O&M)of thermal (coal and natural gas-fired) generation compared to a base case.

It is important to note that these studies comprise a differential analysis: The majority of data are held constant across the analyses, reducing the impact of uncertainty or errors in their estimation.

Indications of Congestion – Where and How Much

Two sets of paths (also known as interfaces or flowgates) were analyzed in this study. One set of ten consists of paths internal to the Northwest and are important to an analysis of congestion on BPA's system. This document refers to these internal paths as flowgates. The second set of eight paths link Oregon and Washington to other regions, including Canada, California, Montana, and Idaho.

Figure 1: Location of transmission paths reported in this analysis



The maximum permissible flows across these paths are shown inWhen flows on a path approach or reach their limit, the line is considered congested. The numerical measure of congestion hours in this report mirrors the method adopted by the WECC TEPPC: The percentage (or equivalently, the number) of hours across the study horizon for which flows are at or above 75%, 90% and 100% of the path's limit is recorded for each case and each path. It is important to recognize that the time above 75% includes not just the hours between 75% and 90%, but hours at any flow above 75%.

While a path loaded to 75% or 90% of its limit will not impose an economic congestion penalty, it provides an indication of risk, as failure of a transmission component elsewhere may immediately send such a path to its limit, with adverse consequences.

Table 1. The limits vary across the various cases analyzed in this study as the transmission network is modified and, in Case 3, in order to examine the effect of relaxing path limits. The cases shown here are characterized in the next section, and more fully defined in a later section. There are additional cases, which are variations on these, and their path limits are the same as those of their root cases.

When flows on a path approach or reach their limit, the line is considered congested. The numerical measure of congestion hours in this report mirrors the method adopted by the WECC TEPPC: The percentage (or equivalently, the number) of hours across the study horizon for which flows are at or above 75%, 90% and 100% of the path's limit is recorded for each case and each path. It is important to recognize that the time above 75% includes not just the hours between 75% and 90%, but hours at any flow above 75%.

While a path loaded to 75% or 90% of its limit will not impose an economic congestion penalty, it provides an indication of risk, as failure of a transmission component elsewhere may immediately send such a path to its limit, with adverse consequences.

Table 1: Flow limits, by case, for reported paths

Internal Paths	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
North of Hanford	4100	4100	99999	4100	4100	4100
North of John Day	7800	7800	99999	8400	8400	7800
Paul - Allston	2250	2250	99999	2990	2250	2990
Raver - Paul	1625	1625	99999	1625	1625	1625
South of Allston	2870	2870	99999	3980	2870	3980
West of Cascades - North	9700	9700	99999	9900	9900	9700
West of Cascades - South	7500	7500	99999	7500	7500	7500
West of John Day	2600	2600	99999	3550	3550	2600
West of McNary	2870	2870	99999	4500	4500	2870
West of Slatt	4100	4100	99999	5500	5500	4100
External Paths	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
Bridger West	2200	2200	2200	2200	2200	2200
Calif.-Oregon Intertie (COI)	4800	4800	4800	4800	4800	4800
Idaho-Northwest	2400	2400	2400	2400	2400	2400
Midpoint - Summer Lake	1500	1500	1500	1500	1500	1500
Montana - Northwest	2200	2200	2200	2200	2200	2200
NW to Canada East BC	300	300	300	300	300	300
NW to Canada West BC	2000*	2000*	2000*	2000*	2000*	2000*
Pacific DC Intertie (PDCI)	3100	3100	3100	3100	3100	3100

* NW to Canada West BC limit is 2,850 MW in summer (May – October)

Impacts of Alternative Approaches on Operating Costs

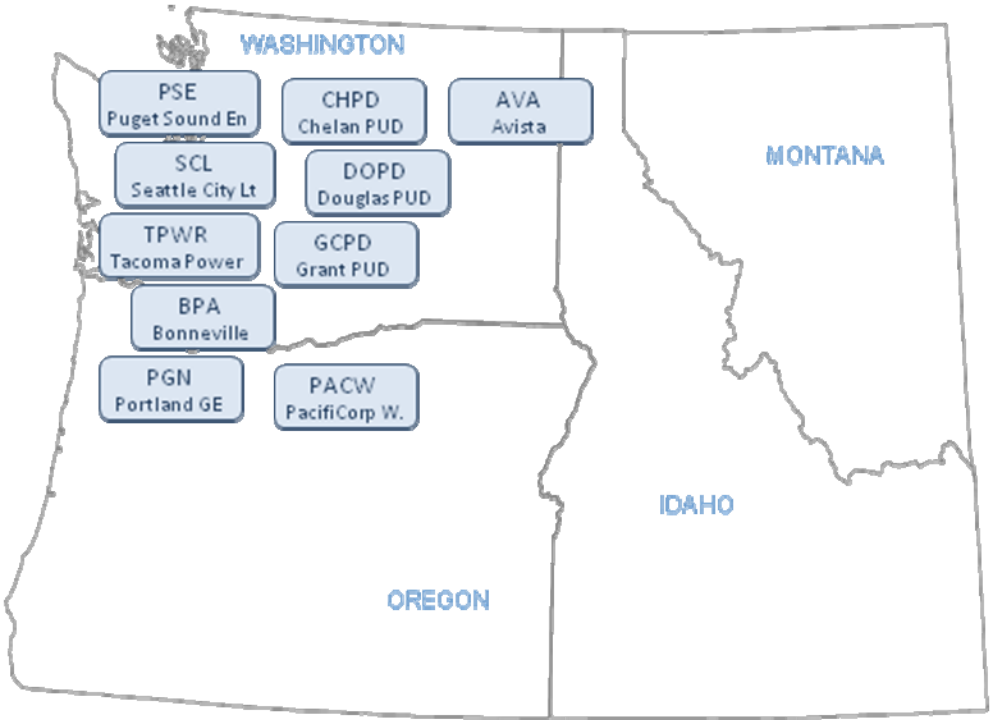
As noted above, a congested path will force the power system to seek a more expensive dispatch to ensure load service. This redispatch can be measured via the sum of variable fuel and O&M costs, compared to the same sum taken in a case with different transmission.

Note that this measure has little value when two cases have different amounts of available generation. In general, it is impractical to ascertain how much of the variable cost change is attributable to the costs of the changed generation availability and how much to redispatch of the generation portfolio and transmission network.

Study Scope – Limited to the BPA Footprint

Production cost modeling in this study has been focused on the BPA transmission footprint (essentially, the Oregon-Washington region). Model data for regions outside the Northwest have not been reviewed or modified, except for a few known errors. However, the data were used in the TEPPC PC1 case published on the WECC web site on August 26, 2008, and were subjected to considerable scrutiny and development (see 'The Initial Case – Which and Why,' below).

Figure 2: Load areas comprising the Northwest region, as defined in GridView modeling



Cases, Scenarios and Alternative Studies

To assess congestion changes on Northwest transmission paths due to Network Open Season resources and potential transmission modifications, a small set of cases were defined before the project began. These have been modified and expanded somewhat as the study has progressed. The initial set was designed to measure changes from a base case, itself derived from a WECC TEPPC case that was adjusted to more closely match BPA's internal transmission planning cases.

The other cases were chosen to measure the impact of adding the NOS resources, the impact of those resources if there were no internal transmission limits, and the benefit of adding transmission projects as defined by the 2008 NOS cluster studies and projects that will best accommodate future needs.

The Initial Case – Which and Why

The initial case chosen was the WECC TEPPC Planning Case 1, or PC1. It is based on the WECC's 2016-2017 Heavy Winter Base Case, and has load and resource information forecasted for calendar year 2017. A study year about one decade in the future is a good fit for the present study, as it examines a time frame where the NOS resources would be in service and transmission projects could be in operation. The two alternatives available from WECC are a 2012 case, which is still under development, and a 2015 case, which has not been updated since 2007. The PC1 case used as the basis for this project was published on the WECC Web site on August 26, 2008. A more recent PC1A' case has been evolved, and some of its improvements have been included in this study.

Creating a 'Valid Starting Point'

The TEPPC PC1 case, also known as the 2017 heavy wind case, contained a number of generic resources added to serve forecasted load growth and to increase the use of renewable resources in the Western Interconnection consistent with current RPS mandates. Those generic resources in the Northwest were removed and replaced by a set of more specific resources.

Where the generic resources in the PC1 study were placed somewhat arbitrarily at major transmission hubs, the replacement resources were attached to more appropriate buses. These resource changes are described in detail later in this report. Some added resources were accompanied by transmission changes to support interconnection.

Loads in the Northwest were also adjusted to match the forecast used internally at BPA and in the 2008 NOS cluster studies. The load levels are about 9% higher than the levels assumed in the PC1A' TEPPC case.

In addition to these data changes, this study used a recently-implemented hydrogeneration dispatch methodology, termed proportional load following (PLF). Whereas the TEPPC PC1 case used a combination of fixed historical hourly hydrogeneration and "base load, peak shave" dispatch, this study used PLF hydroelectric dispatch for Northwest projects identified as having load-following capabilities. Further discussion of these alternative modeling methods is found below in the section "Modeling hydrogeneration in GridView."

This set of modifications produced the 'valid starting point' for the project, referred to as Case 1.

Adding the NOS Resources

The set of resources selected for analysis by the NOS Cluster Study were added in what is called Case 2. Transmission additions and changes were limited to those necessary to interconnect the resources into BPA's network.

Looking at Existing Paths, Unrestricted

To get some characterization of congestion with the NOS resources added, but without mitigating or accommodating transmission, the Case 2 system was examined with internal path limits removed. This was defined as Case 3. In measuring congestion for this case, hours at some

percentage of an essentially infinite limit would not be informative, but the hours above a percentage of the limits that would have been in place is useful.

Adding the West-of-McNary and I-5 Corridor Reinforcements

Case 4 studied the loads and resources of Case 2, with the addition of major components of the West-of-McNary and I-5 Corridor transmission projects. These projects allowed higher limits to be set on a number of internal transmission paths.

Adding Just the West-of-McNary Reinforcements

To decompose the benefits of Case 4, a Case 5 was created which looked at Case 2 with only the West-of-McNary reinforcements added. The Southern Oregon wind projects (the Harney projects) were not included in this case.

Adding Just the I-5 Corridor Reinforcements

As in Case 5, Case 6 looked at Case 2 with only one of the two projects added; in this instance, the I-5 Corridor reinforcements. The Southern Oregon wind projects (the Harney projects) were not included in this case.

Looking at Carbon Dioxide Emission Cost Implications

A set of four cases placed cost penalties on emission of carbon dioxide (CO_2). Allowance costs of $20/ton and $50/ton were analyzed, for Case 2h (base system with NOS resources except Harney added), and for Case 4h (with the addition of the West-of-McNary and I-5 Corridor projects).

Table 2: Table of Study Cases

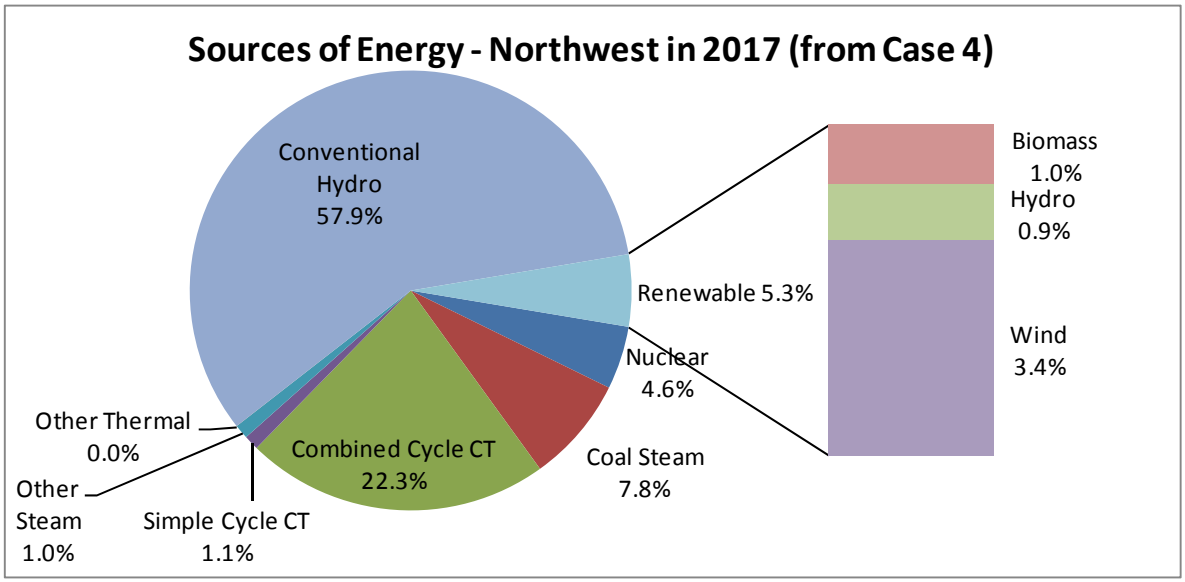
Case	Description	NOS Resources	w/o Harney	West of McNary	I-5 Corridor	CO_2 ($/Ton)
1	Valid starting point					
2	With NOS resources	X				
2h	With NOS resources, without Harney	X	X			
2hC20	NOS resources, no Harney, CO_2 at $20/ton	X	X			$20
2hC50	NOS resources, no Harney, CO_2 at $50/ton	X	X			$50
3	NOS resources, unbounded flowgates	X				
4	NOS resources, WoM & I-5	X		X	X	
4h	NOS resources, no Harney, WoM & I-5	X	X	X	X	
4hC20	NOS res, no Harney, WoM & I-5, CO_2 at $20	X	X	X	X	$20
4hC50	NOS res, no Harney, WoM & I-5, CO_2 at $50	X	X	X	X	$50
5	NOS res, no Harney, WoM	X	X	X		
6	NOS res, no Harney, I-5	X	X		X	

Results and Observations

Resources Used to Serve Loads

Figure 3**Error! Reference source not found.** shows the model-calculated energy used to meet Northwest loads in 2017 by resource category in Case 4, assuming median streamflows and utility implementation of only existing Renewable Portfolio Standards, wherein renewable resources comprise 5.3% of the total.

Figure 3: Sources of Energy in Oregon and Washington, with NOS resources and transmission



This compares to 9.9% in the TEPPC PC4A case, which is designed to provide 15% of the Western Interconnection's energy from renewable sources under a more aggressive RPS implementation than is currently the case.

If additional wind generation is added in the Northwest to provide the same contribution, it is likely that congestion on several Northwest paths would increase. This is because the additional generation is likely to be built in areas where output patterns will not be substantially different from existing wind generation, and the ability of hydrogeneration to reshape the output is depleted. Indeed, the hydroelectric system may already be unable to integrate all of the wind generation shown to be in service in Figure 1, considering the inflexibility of wind output and its need for substantial load following and regulation reserves.

Changes in Generation

Table 3 shows the changes in generation used to meet demands, by category and for each of the cases examined in this study, compared to Case 2, the case with NOS resources added but no transmission or emissions changes. (Case 2 column shows the base MWh, rather than delta.)

Table 3: Generation (MWh) by category and case, shown as difference from Case 2

NOS_Category	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Coal Steam	(59,371)	314,357,410	7,718	14,846	(33,542)	(6,425)
Combined Cycle CT	9,112,555	290,881,099	(1,984,066)	551,677	(87,734)	(211,741)
Conventional Hydro	78	246,170,080	(39)	1	0	21
Import (Neg. Bus Load)	0	4,634,715	0	0	0	0
Nuclear	0	77,944,784	0	0	0	0
Other Steam	860,422	19,488,815	(265,764)	(349,079)	83,463	140,073
Other Thermal	4,073	162,943	(3,001)	(4,486)	(5,070)	8,346
Pumped Hydro	26,369	654,463	(8,351)	2,222	(3,621)	2,353
Renewable Biomass	23,783	6,014,793	(7,782)	(213)	110	16
Renewable Geothermal	0	24,997,779	0	0	0	0
Renewable Hydro	(35)	2,370,156	0	0	0	0
Renewable Solar	0	8,361,280	0	0	0	0
Renewable Wind	(10,072,071)	67,999,836	2,374,042	83	0	(4,625)
Simple Cycle CT	1,022,298	19,752,363	(108,491)	(318,867)	56,650	145,132

Table 4 shows the changes in generation used to meet demands, by category and for each of the CO2 cases examined in this study, compared to Case 2h, the case with NOS resources added but no transmission or emissions changes; and to Case 4h, the same case with the West of McNary and I-5 Corridor reinforcements.

The imposition of CO_2 allowance costs of $20/ton and $50/ton reduced coal-fired generation in favor of natural gas-fired combined cycle and simple cycle combustion turbines. The WECC-wide shift was about 1,000 average megawatts of energy in the $20/ton cases and about 10,000 average megawatts in the $50/ton cases. Transmission congestion on the paths and flowgates monitored in this study were reduced moderately with a $20/ton CO_2 cost (0%-30%) and dramatically (20%-80%) in the $50/ton cases (see Tables 8, 9 and 10). There was little difference in either generation or congestion changes between cases including the NOS resources and those including the resources and the transmission reinforcements.

Table 4: Generation by category for CO_2 Cases, as difference from $0/ton cases

NOS_Category	Case n2h	Case n2h C20	Case n2h C50	Case n4h	Case n4h C20	Case n4h C50
Coal Steam	314,325,493	(8,538,737)	(101,288,735)	314,377,326	(8,473,312)	(101,880,804)
Combined Cycle CT	292,916,268	7,542,754	61,678,915	293,441,696	7,537,443	62,126,046
Conventional Hydro	246,170,054	(34)	(5)	246,170,015	1	(1)
Import (Neg. Bus Load)	4,634,715	0	0	4,634,715	0	0
Nuclear	77,944,784	0	0	77,944,784	0	0
Other Steam	19,722,431	(2,007,861)	2,152,241	19,361,270	(1,985,560)	2,231,876
Other Thermal	165,499	21,572	37,295	159,263	23,116	30,034
Pumped Hydro	653,195	(128,075)	169,984	653,852	(134,167)	182,372
Renewable Biomass	6,022,584	409,788	598,533	6,019,504	418,258	592,636
Renewable Geothermal	24,997,779	0	0	24,997,779	0	0
Renewable Hydro	2,370,156	0	0	2,370,156	0	0
Renewable Solar	8,361,280	0	0	8,361,280	0	0
Renewable Wind	65,637,907	6,251	4,330	65,648,488	0	0
Simple Cycle CT	19,884,657	1,470,582	31,707,910	19,593,826	1,395,380	31,763,092

Transmission Path Utilization and Congestion

The NOS generation, while large in nameplate rating and highly variable in output, is located favorably relative to Northwest transmission and hydro-generation.

- The flexibility of the hydroelectric system, as modeled by the proportional load-following method, but limited in the amount of wind energy accommodated by the hydroelectric system, allows for NOS wind to be integrated largely by hydroelectric redispatch and within transmission constraints[1].

- The West of McNary and I-5 Corridor transmission reinforcements reduce both existing and NOS-caused congestion and frequency of heavy transmission path loading, but don't substantially reduce thermal re-dispatch congestion costs. This is because the redispatch

[1] This analysis did not consider the additional load following and regulation reserves needed to accommodate the uncertainty and high within-hour ramp rates of wind generation, which may reduce the amount of wind generation that can be integrated by existing hydrogeneration.

due to NOS resources can be accomplished largely by the hydroelectric system at the levels studied.

- This analysis doesn't account for transmission revenues associated with firm Available Transmission Capacity reservations, and transmission services marketed or foregone.
- It isn't known, at this point, how much additional wind integration could be accomplished without large thermal congestion costs or without the displacement of reliable thermal generation impacting system reliability.

This study is not a resource adequacy study, nor a reliability analysis. Thermal displacement by the NOS generation affects gas-fired generation levels (with some affected plants near loads) and coal-fired generation levels in the Northwest and Eastern WECC. This change in generation profile should be reviewed for reliability effects.

- The wind profiles for NOS generation show low capacity factors on peak hours. Further accounting of the study results will show which thermal units had their energy production displaced and how much thermal and hydro generating capacity remains available for reserves and regulation.

Path loadings are considered high if there are many hours at or above 75% of the path's limit. This indicator is used in this type of analysis because it considers actual flows and not the limitations imposed by contracted transmission and scheduled ATC methodology. Generally, it has been seen from historical path loading analyses that short-term transmission service reservations and ATC are limited when paths have large numbers of hours with actual flows above 75% of Operating Transfer Capability.

The West of McNary and I-5 Corridor reinforcement projects reduce or eliminate almost all transmission congestion and increased path loading that result from NOS generation additions; and significantly reduces congestion existing before the NOS additions.

- The West of McNary and I-5 Corridor reinforcement projects also allow increases in other path ratings, such as North of John Day.
- The West of McNary and I-5 Corridor reinforcements dramatically reduce the number of hours that path loadings are at or above 90% of their limits.

The I-5 reinforcement reduces hours of path loading above 75% of rating on the Paul-Allston-Keeler path by approximately 500 hours per year, and loadings at or above 90% by 300 hours – with or without the NOS generation additions.

The following tables show the number of hours during the study year, 2017, that selected paths (within the Northwest and connecting to external regions) are loaded to 75%, 90% and 100% of their path limits.

The addition of the NOS generation with integrating transmission but without reinforcements increases congestion on internal Northwest paths. Total flowgate actual flow levels exceed 75% of their ratings an additional 570 hours in 2017, including an additional 70 hours in excess of 90% of their limits. This doesn't consider hours in which path limits may be reduced due to maintenance or other outages.

Table 5: Table of path utilization, hours at or above 75% of path limit

Internal Paths	Case 1	Case 2	Case 2h	Case 3[2]	Case 4	Case 4h	Case 5	Case 6
North of Hanford	0	0	0	1	0	0	0	0
North of John Day	125	153	158	209	82	206	89	163
Paul - Allston	811	774	787	677	274	234	750	328
Raver - Paul	0	0	0	0	0	0	0	0
South of Allston	588	575	575	517	129	109	545	157
West of Cascades - North	12	71	52	64	77	62	38	100
West of Cascades - South	27	9	6	4	0	0	0	3
West of John Day	613	735	669	685	84	82	146	465
West of McNary	475	549	580	581	0	0	0	514
West of Slatt	383	743	764	734	28	33	43	677
External Paths	**Case 1**	**Case 2**	**Case 2h**	**Case 3**	**Case 4**	**Case 4h**	**Case 5**	**Case 6**
Bridger West	7028	6589	6675	6630	6637	6689	6713	6728
Calif.-Oregon Intertie (COI)	727	1344	1121	1346	1405	1183	1132	1138
Idaho-Northwest	24	26	15	25	23	23	24	19
Midpoint - Summer Lake	1133	829	865	826	597	848	885	910
Montana - Northwest	6020	5892	5869	5782	5735	5815	5667	5797
NW to Canada East BC	2125	2194	2118	1994	2181	2105	2209	2031
NW to Canada West BC	597	747	745	760	802	784	764	757
Pacific DC Intertie (PDCI)	45	63	63	142	89	85	129	32

[2] Hours above a given percentage of the path limit doesn't have significance for Case 3, where limits are essentially infinite. The hours reported here are those above levels relative to the Case 2 limit.

The West of McNary and I-5 Corridor reinforcements reduce the number of hours on which flowgates are at or above 75% of their ratings by approximately 3,000 hours, and eliminates nearly all hours that flowgate loadings are at 100% of rating with all lines in service (for the loads and resources portfolio studied). The West of McNary reinforcements alone reduce hours of flowgate loading above 75% of rating by about 2,000 hours per year, and hours above 90% of rating by 40%.

Table 6: Table of path utilization, hours at or above 90% of path limit

Internal Paths	Case 1	Case 2	Case 2h	Case 3	Case 4	Case 4h	Case 5	Case 6
North of Hanford	0	0	0	0	0	0	0	0
North of John Day	0	0	0	3	0	1	0	0
Paul - Allston	370	357	360	226	4	3	295	10
Raver - Paul	0	0	0	0	0	0	0	0
South of Allston	276	267	268	227	0	0	233	0
West of Cascades - North	0	0	0	0	0	0	0	0
West of Cascades - South	0	0	0	0	0	0	0	0
West of John Day	249	316	286	260	22	24	49	170
West of McNary	1	2	3	6	0	0	0	1
West of Slatt	13	36	35	42	0	0	0	29
External Paths	**Case 1**	**Case 2**	**Case 2h**	**Case 3**	**Case 4**	**Case 4h**	**Case 5**	**Case 6**
Bridger West	3477	3078	3117	3095	3067	3150	3169	3162
Calif.-Oregon Intertie (COI)	294	484	419	493	514	443	426	411
Idaho-Northwest	0	0	0	0	0	0	0	0
Midpoint - Summer Lake	24	32	16	23	17	15	20	27
Montana - Northwest	3000	2737	2639	2619	2384	2424	2378	2577
NW to Canada East BC	1654	1768	1687	1589	1731	1681	1735	1667
NW to Canada West BC	306	432	410	438	461	437	431	433
Pacific DC Intertie (PDCI)	0	0	0	58	29	25	56	0

Table 7: Table of path utilization, hours at 100% of path limit

Internal Paths	Case 1	Case 2	Case 2h	Case 3	Case 4	Case 4h	Case 5	Case 6
North of Hanford	0	0	0	0	0	0	0	0
North of John Day	0	0	0	0	0	0	0	0
Paul - Allston	56	63	63	31	0	0	45	0
Raver - Paul	0	0	0	0	0	0	0	0
South of Allston	79	72	77	50	0	0	58	0
West of Cascades - North	0	0	0	0	0	0	0	0
West of Cascades - South	0	0	0	0	0	0	0	0
West of John Day	133	154	139	96	1	0	9	84
West of McNary	0	0	0	0	0	0	0	0
West of Slatt	0	0	0	0	0	0	0	0
External Paths	**Case 1**	**Case 2**	**Case 2h**	**Case 3**	**Case 4**	**Case 4h**	**Case 5**	**Case 6**
Bridger West	1456	1215	1225	1203	1157	1194	1213	1233
Calif.-Oregon Intertie (COI)	48	57	69	67	74	51	55	56
Idaho-Northwest	0	0	0	0	0	0	0	0
Midpoint - Summer Lake	0	0	0	0	0	0	0	0
Montana - Northwest	992	788	745	717	593	609	621	714
NW to Canada East BC	1426	1531	1478	1394	1515	1456	1525	1452
NW to Canada West BC	163	246	225	247	265	256	237	233
Pacific DC Intertie (PDCI)	0	0	0	9	6	6	24	0

Table 8: Table of path utilization, hours at or above 75% of path limit, CO_2 cases

Internal Paths	Case 2h	Case 2h C20	Case 2h C50	Case 4h	Case 4h C20	Case 4h C50
North of Hanford	0	0	0	0	0	0
North of John Day	158	121	19	101	65	2
Paul - Allston	787	736	228	234	249	22
Raver - Paul	0	0	3	0	0	0
South of Allston	575	538	239	109	85	15
West of Cascades - North	52	70	43	62	67	52
West of Cascades - South	6	9	8	0	0	0
West of John Day	669	668	669	82	77	102
West of McNary	580	511	390	0	0	0
West of Slatt	764	621	325	33	19	4
External Paths	**Case 2h**	**Case 2h C20**	**Case 2h C50**	**Case 4h**	**Case 4h C20**	**Case 4h C50**
Bridger West	6675	6545	2083	6689	6587	2407
Calif.-Oregon Intertie (COI)	1121	863	194	1183	918	206
Idaho-Northwest	15	52	0	23	51	0
Midpoint - Summer Lake	865	865	5	848	741	2
Montana - Northwest	5869	5180	3597	5815	4994	2842
NW to Canada East BC	2118	2173	2019	2105	2116	2028
NW to Canada West BC	745	714	714	784	797	783
Pacific DC Intertie (PDCI)	63	43	46	85	68	88

Table 9: Table of path utilization, hours at or above 90% of path limit, CO_2 cases

Internal Paths	Case 2h	Case 2h C20	Case 2h C50	Case 4h	Case 4h C20	Case 4h C50
North of Hanford	0	0	0	0	0	0
North of John Day	0	0	0	0	0	0
Paul - Allston	360	320	31	3	3	0
Raver - Paul	0	0	0	0	0	0
South of Allston	268	204	55	0	0	0
West of Cascades - North	0	0	0	0	0	0
West of Cascades - South	0	0	0	0	0	0
West of John Day	286	287	272	24	24	29
West of McNary	3	2	0	0	0	0
West of Slatt	35	26	3	0	0	0
External Paths	**Case 2h**	**Case 2h C20**	**Case 2h C50**	**Case 4h**	**Case 4h C20**	**Case 4h C50**
Bridger West	3117	2853	390	3150	2881	558
Calif.-Oregon Intertie (COI)	419	272	30	443	311	29
Idaho-Northwest	0	0	0	0	0	0
Midpoint - Summer Lake	16	47	0	15	40	0
Montana - Northwest	2639	2767	2217	2424	2306	1460
NW to Canada East BC	1687	1731	1503	1681	1663	1482
NW to Canada West BC	410	396	381	437	445	438
Pacific DC Intertie (PDCI)	0	0	0	25	23	31

Table 10: Table of path utilization, hours at 100% of path limit, CO_2 cases

Internal Paths	Case 2h	Case 2h C20	Case 2h C50	Case 4h	Case 4h C20	Case 4h C50
North of Hanford	0	0	0	0	0	0
North of John Day	0	0	0	0	0	0
Paul - Allston	63	56	0	0	0	0
Raver - Paul	0	0	0	0	0	0
South of Allston	77	39	6	0	0	0
West of Cascades - North	0	0	0	0	0	0
West of Cascades - South	0	0	0	0	0	0
West of John Day	139	136	132	0	0	0
West of McNary	0	0	0	0	0	0
West of Slatt	0	0	0	0	0	0
External Paths	**Case 2h**	**Case 2h C20**	**Case 2h C50**	**Case 4h**	**Case 4h C20**	**Case 4h C50**
Bridger West	1225	1060	79	1194	1032	98
Calif.-Oregon Intertie (COI)	69	24	0	51	21	0
Idaho-Northwest	0	0	0	0	0	0
Midpoint - Summer Lake	0	0	0	0	0	0
Montana - Northwest	745	1008	1041	609	715	489
NW to Canada East BC	1478	1481	1197	1456	1457	1192
NW to Canada West BC	225	204	203	256	251	238
Pacific DC Intertie (PDCI)	0	0	0	6	7	9

Variable Production Costs

Addition of the full set of NOS generation, which is mostly wind-powered, can potentially decrease thermal production costs in the Northwest region by approximately $85 million per year. Further, NOS wind-powered generation allows redirection of energy to other regions in the Western Interconnection, reducing variable costs by $540 million annually.

Addition of the West of McNary and I-5 Corridor reinforcement projects allows additional wind and hydroelectric optimization to reduce Northwest variable costs a further $8-$10 million annually in the Northwest and $17 million a year in the Western Interconnection.

These cost savings, while derived for the year 2017, have some stability across years. Two factors affecting levels of path usage are increasing construction of generating resources in resource-rich areas, which are remote from load centers and cause increased loading, and technological development of distributed generation that might be sited close to load centers and so reduce path usage. In both cases, significant time is required to build projects and adopt technology, implying a slow change in annual cost benefits of transmission projects.

However, the magnitude of these uncertainties and their annual cost implications cannot be established within the scope of this study.

An issue which should be evaluated, but which is outside the scope of this study, is the attribution of cost savings that arise from construction of renewable resources and the transmission that enables their energy to reach customers. When the NOS generators are added to the Northwest region and operated, along with all other generators in the Western Interconnection, as a single-owner system, there are substantial reductions in thermal production costs in regions outside the Northwest.

It is not possible to ascertain, from the GridView model, where the energy from a particular generator goes – whether the electricity is used to serve Northwest loads and the displaced (probably higher-cost) generation is sent to other regions, or whether the electricity goes directly to the other regions to reduce costs there.

When the NOS generation reduction ultimately comes from, say, simple cycle combustion turbines, there may be Renewable Energy Credits available. The value of these credits would at least equal to avoided production costs at these generators, and potentially equal the market clearing price.

The following tables summarize the results, for the Western Interconnection and for the Northwest, for the cases studied. They show the amount of generation and load, and the variable costs of thermal generation.

Table 11: Table of generation, load and costs for WECC by case

WECC		Total Generation (MWh)	Generation Cost (M$)	Served Load (MWh)	Interchange & Losses (MWh)	Unserved Load MWh)
Case 1	Starting Point	1,073,162,009	$ 25,579	1,038,963,812	34,198,197	-
Case 2	+ NOS Resources	1,073,332,652	$ 25,040	1,038,963,812	34,368,840	-
Case 2h	2 - Harney Wind	1,073,348,911	$ 25,156	1,038,963,812	34,385,099	-
Case 3	2, No path limits	1,073,363,717	$ 25,036	1,038,963,812	34,399,905	-
Case 4	2 + WoMR, I-5 R	1,073,257,501	$ 25,023	1,038,963,812	34,293,689	-
Case 4h	2h + WoMR, I-5 R	1,073,276,702	$ 25,138	1,038,963,812	34,312,890	-
Case 5	2h + WoMR	1,073,292,177	$ 25,143	1,038,963,812	34,328,365	-
Case 6	2h + I-5 Reinf.	1,073,362,477	$ 25,149	1,038,963,812	34,398,665	-
Difference from Case 2 (Valid Starting Point + NOS Resources)						
Case 1	Starting Point	(170,643)	$ 539	-	(170,643)	-
Case 2	+ NOS Resources	-	$ -	-	-	-
Case 2h	2 - Harney Wind	16,259	$ 116	-	16,259	-
Case 3	2, No path limits	31,065	$ (4)	-	31,065	-
Case 4	2 + WoMR, I-5 R	(75,151)	$ (17)	-	(75,151)	-
Case 4h	2h + WoMR, I-5 R	(55,950)	$ 98	-	(55,950)	-
Case 5	2h + WoMR	(40,475)	$ 104	-	(40,475)	-
Case 6	2h + I-5 Reinf.	29,825	$ 109	-	29,825	-

Table 12: Table of generation, load and costs for Northwest by case

Northwest		Total Generation (MWh)	Generation Cost (M$)	Served Load (MWh)	Interchange & Losses (MWh)	Unserved Load MWh)
Case 1	Starting Point	203,803,171	$ 2,991	203,813,580	(10,408)	-
Case 2	+ NOS Resources	204,082,943	$ 2,907	203,813,580	269,364	-
Case 2h	2 - Harney Wind	204,421,332	$ 2,919	203,813,580	607,753	-
Case 3	2, No path limits	204,114,032	$ 2,906	203,813,580	300,452	-
Case 4	2 + WoMR, I-5 R	204,072,600	$ 2,897	203,813,580	259,021	-
Case 4h	2h + WoMR, I-5 R	204,437,290	$ 2,911	203,813,580	623,710	-
Case 5	2h + WoMR	204,412,968	$ 2,912	203,813,580	599,389	-
Case 6	2h + I-5 Reinf.	204,415,675	$ 2,916	203,813,580	602,096	-
Difference from Case 2 (Valid Starting Point + NOS Resources)						
Case 1	Starting Point	(279,772)	$ 84	-	(279,772)	-
Case 2	+ NOS Resources	-	$ -	-	-	-
Case 2h	2 - Harney Wind	338,389	$ 12	-	338,389	-
Case 3	2, No path limits	31,089	$ (1)	-	31,089	-
Case 4	2 + WoMR, I-5 R	(10,343)	$ (10)	-	(10,343)	-
Case 4h	2h + WoMR, I-5 R	354,347	$ 4	-	354,347	-
Case 5	2h + WoMR	330,025	$ 4	-	330,025	-
Case 6	2h + I-5 Reinf.	332,732	$ 9	-	332,732	-

Table 13: Table of generation, load and costs for WECC by case, with CO_2 costs

(Note: Values for Total Generation and Interchange & Losses are in terawatt-hours, each equal to one million megawatt-hours, in order to fit the page.)

WEC C	Allowance Cost ($/Ton)	Total Generation (TWh)	Generation Cost ($M)	Interchange & Losses (TWh)	Unserved Load (MWh)	CO_2 Emitted (Million	CO_2 Allowance Costs
Case 2h C00	$0	1,073.3	25,156.2	34.4	-	427.9	-
Case 2h C20	$20	1,072.3	25,321.2	33.3	-	417.1	9,196.1
Case 2h C50	$50	1,067.2	28,081.3	28.2	-	342.0	18,851.4
Case 4h C00	$0	1,073.3	25,137.7	34.3	-	427.8	-
Case 4h C20	$20	1,072.3	25,301.5	33.3	-	417.0	9,194.2
Case 4h C50	$50	1,067.1	28,085.4	28.1	-	341.6	18,827.4
Difference from cases with CO_2 allowance cost at $0/Ton							
Case 2h C00	$0	-	0.0	-	-	-	-
Case 2h C20	$20	(1.0)	164.9	(1.0)	-	(10.8)	9,196.1
Case 2h C50	$50	(6.2)	2,925.0	(6.2)	-	(85.8)	18,851.4
Case 4h C00	$0	-	0.0	-	-	-	-
Case 4h C20	$20	(1.0)	163.7	(1.0)	-	(10.7)	9,194.2
Case 4h C50	$50	(6.2)	2,947.6	(6.2)	-	(86.2)	18,827.4

Table 14: Table of Northwest generation, load and costs by case, with CO_2 costs

Northwest	Allowance Cost ($/Ton)	Total Generation (TWh)	Generation Cost ($M)	Interchange & Losses (TWh)	Unserved Load (MWh)	CO_2 Emitted (Million Metric Tons)	CO_2 Allowance Costs ($M)
Case 2h C00	$0	204.4	2,919.1	0.6	-	33.6	-
Case 2h C20	$20	203.6	2,891.6	(0.2)	-	33.2	732.0
Case 2h C50	$50	204.0	2,959.9	0.2	-	31.3	1,726.1
Case 4h C00	$0	204.4	2,911.4	0.6	-	33.5	-
Case 4h C20	$20	203.6	2,883.3	(0.3)	-	33.1	730.5
Case 4h C50	$50	203.7	2,946.6	(0.1)	-	31.0	1,711.2
Difference from cases with CO_2 allowance cost at $0/Ton							
Case 2h C00	-	0.0	-	-	-	-	-
Case 2h C20	(0.8)	(27.5)	(0.8)	-	(0.4)	732.0	732.0
Case 2h C50	(0.4)	40.7	(0.4)	-	(2.3)	1,726.1	1,726.1
Case 4h C00	-	0.0	-	-	-	-	-
Case 4h C20	(0.9)	(28.1)	(0.9)	-	(0.4)	730.5	730.5
Case 4h C50	(0.7)	35.2	(0.7)	-	(2.5)	1,711.2	1,711.2

Modeling Considerations

The WECC TEPPC Transmission and Production Cost Modeling Effort

The Transmission Expansion Planning Policy Committee of the WECC directs the preparation, execution and analysis of WECC economic transmission expansion planning studies. Technical activities in this regard include collection and provision of data in support of transmission planning, primarily through security-constrained optimal power flow production cost modeling. TEPPC's three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning.

The TEPPC created a Technical Advisory Subcommittee to carry out the data collection and modeling efforts of the WECC with regard to economic studies. TAS has four work groups dedicated to parts of this effort: the Historical Analysis Work Group, the Data Work Group, the Models Work Group and the Studies Work Group.

The Data Development Effort

All four work groups of the TEPPC Technical Analysis Subcommittee have contributed to the data used in regional economic power system simulation at the WECC. Historical data are acquired, adopted and analyzed to provide hourly shapes and values for loads, hydrogeneration, wind and other resources. The data work group collects and evaluates alternative sources of power system information, such as heat rates and operating characteristics for thermal generators, fuel prices and operating costs, among others. The model work group strives to identify and develop improved methods for modeling power system commitment and dispatch, such as the proportional load following hydro model described below, and acquires or develops the parametric data required by the models. Finally, the studies work group creates and executes the study plans, determining what studies are to be performed at the WECC and consequently what data are needed for current efforts.

The Model Used: ABB GridView

GridView is a detailed and capable simulation model based on linear and dynamic programming, and includes thermal unit commitment and dispatch, hydrogeneration and pumped storage scheduling, wind modeling and so on. The model performs an optimal power flow using security constrained generating unit commitment and dispatch, including co-optimization of energy and ancillary service needs, which provides detailed and flexible modeling of transmission and generation.

GridView performs an hourly chronological simulation for periods from one day to multiple years. It is capable of Monte Carlo simulation to support risk and reliability analyses. It has provision for modeling bid strategies and emissions policies.

The model uses Microsoft Access databases organized at the global (GridView), project and case levels. The case databases for the Western Interconnection are between 30 and 60 megabytes in size, while model output, stored in proprietary binary files, consumes about 2 gigabytes per case. GridView's graphical user interface provides a number of mechanisms for examining and modifying input data and selecting, viewing and exporting outputs.

ABB has provided a method to convert the PDF databases developed by the WECC TEPPC into GridView format. The general characteristics of the Ventyx PROMOD model and the GridView model are sufficiently comparable to make the conversion fairly robust and efficient.

Modeling Hydrogeneration in GridView

The complexity in operating large hydroelectric systems, where output is a function of stream flows, reservoir content, rates of discharge through powerhouses and spillways, and myriad constraints related to flood control, fisheries, recreation, irrigation, releases into downstream projects and so on, make simulation of these projects problematical.

The initial response to these difficulties by the model developers was to require the user to input hourly generation values for these projects. However, this approach removes any ability of the hydroelectric system to change operation to match loads and the output of other resources. In the WECC, which derives a large fraction of its energy from hydro, this is a serious shortcoming.

GridView and other models have made an effort to better accommodate hydroelectric generation by using a base load, peak-shaving methodology. Some portion of available megawatt-hours is placed in each hour of a period (perhaps a month) at equal levels to provide a constant output. The remaining generation is then assigned to hours where the load is largest, in amounts equal to the maximum capability of the plant less the base-load level.

The next level of hydroelectric generation modeling is to do what is termed proportional load-following (PLF). This is a more sophisticated shaping method than base load, peak-shaving hydro, where the amount of generation in each hour is set in proportion to the per unit load. For instance, where a generator is deemed able to precisely mimic the load shape (its 'k-factor' is 1.0), the ratio of hydrogeneration in two hours is the same as the ratio of load in the same two hours. See the section "Proportional Load Following Hydrogeneration Dispatch" below.

The most recent, and most complex, level of hydro modeling in PROMOD and GridView is termed 'dynamic hydro' and attempts to account for a number of the operational complexities of these projects. Such a model is being developed in GridView and will accommodate reservoir accounting, routing of discharges, accretions and depletions respecting lag times between upstream release and downstream arrival. This modeling capability was not available for this study.

The Load-Hydro-Wind Issue

Like most power system simulation models, GridView does not have a sophisticated system for developing forecasted hourly energy demands. It relies on user-generated hourly loads for what it calls Load Areas that are approximately mapped, in the WECC, to Balancing Authorities.

Similarly, resources with more-or-less random output, like wind, solar power and smaller hydroelectric projects, are also provided as hourly data streams by the user. As noted above, much of the WECC's regional hydrogeneration may be modeled as fixed hourly inputs as well.

In an effort to provide a more realistic simulation, hourly loads and fixed generation are usually abstracted from historical data. A 'typical' historical year might be chosen, or hourly data from a sample of historical years might be averaged.

These hourly shapes or patterns are then scaled to match forecasted monthly or annual values; most often, peak and energy values are forecasted for each period and the hourly shapes are then scaled in such a way that the largest hourly value equals the forecasted peak and the sum of the hourly values equals the energy forecast.

In studies with substantial hydro-generation, a first cut at providing the model with consistent load and hydrogeneration data uses shapes from the same historical year. If other operational constraints on the hydroelectric system remain fairly constant, and if the availability and characteristics of other generating resources do not change substantially, this technique will provide a credible hydrogeneration profile to serve the load.

The introduction of a large amount of wind-powered generating capacity, which is poorly correlated with load, complicates the effort to shape hydrogeneration. The lack of control over when wind energy is available requires that flexible, dispatchable resources change their operation to accommodate the wind output, or the wind output must be rejected (or 'spilled'). Since wind-powered generation has essentially zero incremental cost and modest environmental impact, there is strong incentive to accept it to the extent that output from other resources may be modified.

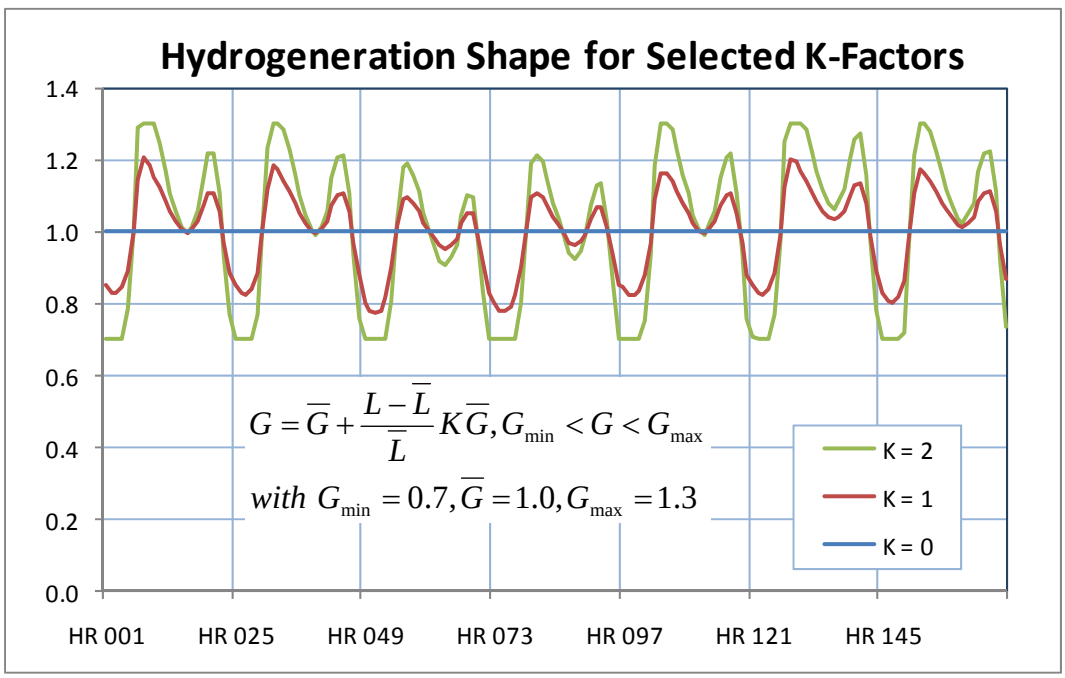
GridView provides a mechanism by which the modeler may specify the amount of wind-powered generation that is to be accommodated by hydrogeneration. This mechanism is based on the proportional load-following hydroelectric dispatch model and its integration with GridView's commitment and dispatch algorithm.

Proportional Load Following Hydrogeneration Dispatch

Hydroelectric projects with access to sufficient storage, either locally or at upstream projects, may be flexibly dispatched to produce electricity that follows a varying pattern, most often the demand for electricity by customers. Analysis of historical correlations between hydroelectric project generation and load show that it is reasonable to designate various projects as having the ability to follow loads; the degree of this ability is referred to as the 'k-factor'.

Figure 4 shows how the ability to shape hydrogeneration is affected by the k-factor; when it is zero, the project produces a flat output equal to its period average energy; when it's one, the project can closely replicate the shape of load over all hours; and when it's two, the project can actually generate with twice the amplitude of the load. The algorithm for proportional load following allows for limits to be set on maximum and minimum hourly generation from the project, as illustrated in the diagram for the k=2 curve. (The vertical scale measures the 'per unit' output of the project's average energy and per unit of the average energy load, to provide a dimensionless basis for comparison.)

Figure 4: Examples of proportional load following for different k-factors



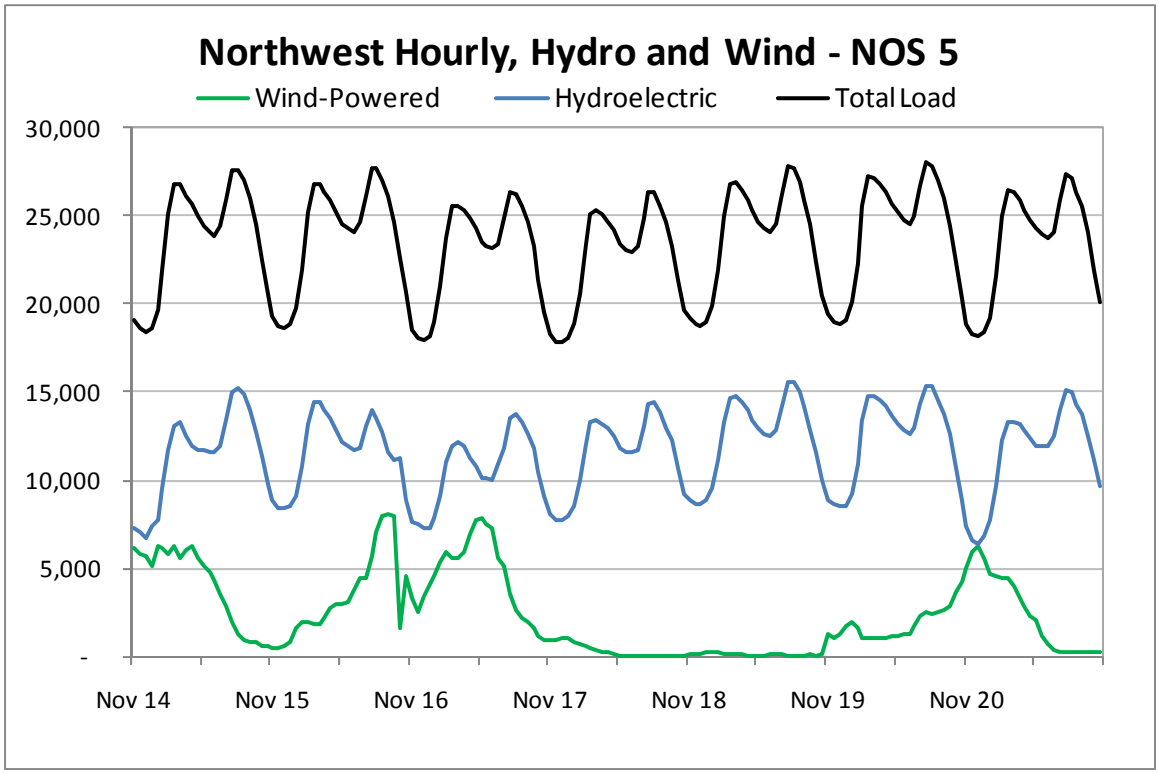
The Grand Coulee project, for example, is constrained by flood control, irrigation requirements, and a limitation on maximum water releases per day, but otherwise has considerable flexibility in its dispatch. Its monthly k factor ranges from 3.0 to 5.62 under median streamflow conditions (represented by 2002 actual hourly generation data). In contrast, the John Day project has more limited storage and additional operational constraints. Consequently, its k factor ranges from 0.84 to 1.52 under median streamflow conditions.

Because hydrogeneration supplies about 75% of Northwest electricity needs (in a median streamflow year), the PLF method is important to provide a reasonable approximation of actual hydroelectric dispatch to serve load. In past studies by TEPPC and SSG-WI[3], when hourly hydrogeneration from a historical year was directly used by the model, it was also necessary to use the hourly loads from the same historical year, leading to a mismatch in load assumptions in the studies, since the year selected for median streamflows in the Northwest was a dry year in California.

The use of PLF logic not only provides better coordination of hydrogeneration with load, it also allows for modeling of wind-hydro-load integration.

In GridView's logic, proportional load following hydrogeneration is dispatched against the regional load, less any resources that have fixed hourly outputs in that region. This association by region provides a mechanism to define which resources can be accommodated by hydrogeneration: In our case, wind resources assigned to the Northwest region are integrated, while those assigned to a 'DUMMY' region will be dispatched after hydro. If wind-powered generation from these projects cannot find load to serve economically, it is 'spilled'.

Figure 5: Sample modification of hydrogeneration to accommodate wind power



[3] The Seams Steering Group – Western Interconnection was the predecessor organization to the WECC TEPPC and performed economic transmission expansion planning studies for the Western US.

In this study, 3,000 MW of wind generation in the Northwest are assumed to be integrated by Northwest proportional load-following hydrogeneration. Wind in excess of this sum is either integrated by redispatch of other resources or, where constraints prevent its delivery, by rejecting or 'spilling' the energy.

Modeling Caveats

As with any computer simulation model, there are differences between what the GridView model is able to simulate and what happens in the real world. It is generally impossible to fully represent the behavior of real systems and, although the physics of power plant and transmission operation are well known, human constructs such as power markets, scheduling and dispatch procedures, and rules for generation and transmission operation are complex and can only be modestly represented. Further, the characteristics of generators and markets are mostly kept confidential to protect or enhance the trading position of market participants, requiring the use of generic or estimated data.

Single-System Commitment and Dispatch in a Heterogeneous Market

The GridView model is capable of simulating power contracts, generator and load bidding systems, demand-response resources, and other market constructs to more closely represent real-world operation. However, the Western Interconnection operates with a wide diversity of market models, from the market clearing price model of the California Independent System Operator, to power trading exchanges like ICE, to many types of bi-lateral short and long term contracts.

This complexity, combined with the proprietary nature of nearly all information regarding the details of these markets and their transactions, make a close representation of actual market operations impossible.

The simulation of the Western Interconnection as a single-operator dispatch, based on cost of production and delivery, represents an outcome that is probably over-optimistic, given the hybrid nature of the mostly bilateral markets in the West. However, on a comparative basis, GridView's dispatch of the lowest incremental-cost resources to serve load, subject to operational and delivery constraints, is reasonable. In this sense the simulation serves as a bookend: any other operation would be less economically efficient.

Single-Trajectory Modeling

The GridView model executes for between seven and ten hours to simulate one year of generation commitment and dispatch in the Western Electricity Coordinating Council. The resulting two gigabytes of output represent a single trajectory into the future – a so-called point estimate.

GridView has the ability to perform random (Monte Carlo) simulation of a number of parameters, including generator forced outages. However, the variation in output among these trials is of the same order of magnitude as the changes our differential analysis is working to detect. Consequently, a large number of trials would be required to get sufficient convergence of measurements, requiring a prohibitive amount of computer time.

In addition, our analysis is based on a single streamflow condition, approximating median (50-50) flows. Both the volume and temporal and geographical distribution of streamflows are subject to wide variation.

Wind generation, directly correlated to wind flows that are highly variable, is also represented as a single set of hourly wind trajectories for each geographical wind region.

Finally, the analysis uses a single hourly load forecast for the WECC. Future electricity demands are subject to economic, policy, technological, climatological and meteorological uncertainties.

All of these un-simulated uncertainties notwithstanding, it must be noted that the model process 8,760 hours in a year, each of which incorporates variation in most of these parameters.

Development of the Cases

This section of the report provides details on the data assumptions and the modifications made in preparing the study cases.

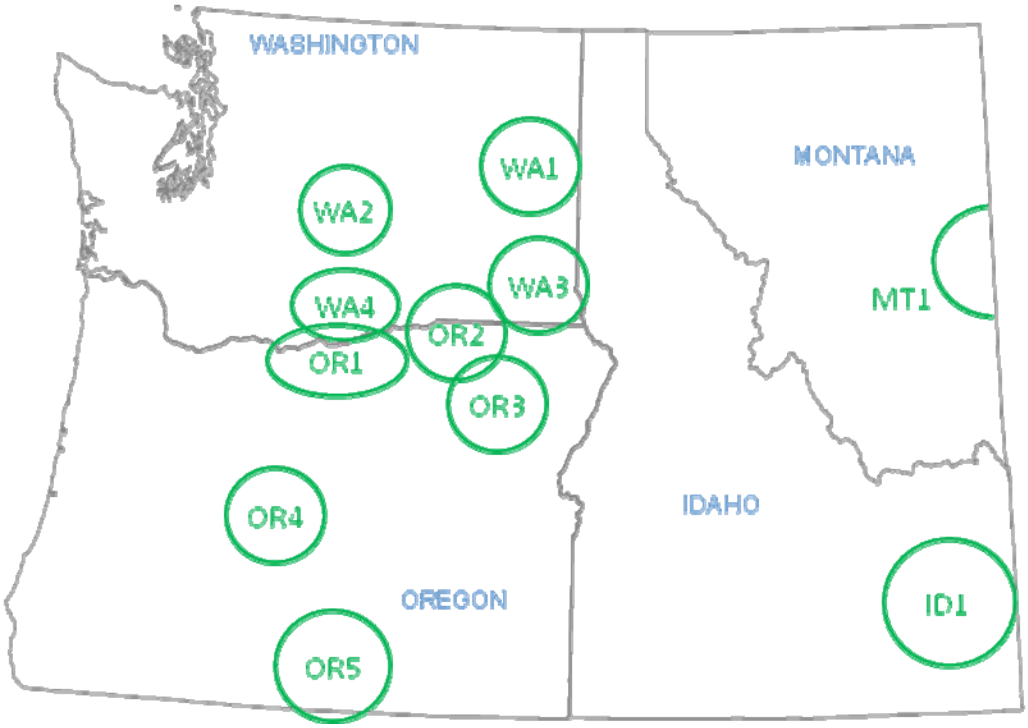
Acquiring and Fixing the TEPPC PC1 Case

The WECC TEPPC's Technical Analysis Subcommittee (TAS), responsible for development of data, assumptions, modeling methods and for execution of studies, oversees the activities of four work groups that prepare data for security-constrained optimal power flow production cost models. WECC staff also executes some studies for TAS using the Ventyx PROMOD model and performs data analysis and reporting. The model data developed by the TAS work groups are made available for other models via TEPPC's Portable Database Format database. In turn, ABB has created tools to import the PDF databases into its proprietary GridView format. This study is based on the TEPPC PC1 case, published on the WECC Web site on August 26, 2008.

Wind Curves for the Northwest

Subsequent to publication of the PC1 case in August, the WECC TEPPC adopted wind shapes developed from work done by the National Renewable Energy Laboratory.

Figure 6: Map of areas associated with wind shapes in Oregon and Washington



The NREL work interpolated historical meteorological data to produce a 'meso-scale' set of wind profiles for the United States on a 2 kilometer by 2 kilometer grid at time intervals of 10 minutes

and 60 minutes. Generic shapes were abstracted for geographical regions within the Western Interconnection that comprise likely locations for wind-powered generators.

There are five hourly profiles for Oregon and four for Washington. While of recent origin and still under review by WECC, the wind data are considered superior to the previous amalgam of curves, in particular because they are geographically and temporally consistent.

For additional detail on these wind profiles, see the WECC paper by Bradley Nickell entitled "TEPPC Renewable Energy Cases, Renewable Generation Information" dated September 12, 2008.

Heat Rate Deficiencies

Production cost modeling at the WECC is currently done on the Ventyx PROMOD platform. However, the WECC has developed a database standard, termed the Portable Data Format, which allows PROMOD data to be placed in a Microsoft Access database in a more generic format that is in turn amenable to import by other models.

ABB has developed a data import tool that accommodates the PDF architecture, but minor defects persist. One of these relates to heat rate curves; some generators' data is not imported correctly. Corrections were made in this project for 26 units.

Missing Emissions Data

In developing emission rates for generators at the WECC, some generator units were overlooked. Updates developed since the August 26, 2008, PDF release have been applied to the GridView dataset.

Creating a Valid Starting Point

The root case for this project is Case 1, termed a 'valid starting point.' As described above, the PC1 case was modified to bring it into closer agreement with BPA's internal forecasts and modeling assumptions.

Removing Resources

Eighteen generators were removed from the initial PC1 starting case. Many of them were the generic 'RPS' generators added by TEPPC in creating the future 2017 case with target renewable levels.

Table 15: Table of removed resources in Case 1

Bus No.	Bus Name	Volt - age	Load Area	Name	Long Name	Capa-city (MW)	Type
40321	CUSTER W	230	BPA	BPCherryS1	BP Cherry Point S1 WA		Thermal
48359	RATHGEN1	13.8	AVA	RathdrmA1	Rathdrum A1 Rathdrum ID		Thermal
48361	RATHGEN2	13.8	AVA	RathdrmA2	Rathdrum A2 Rathdrum ID		Thermal
40883	RESTON	230	BPA	RpsORbio1	RPS Oregon BIO 1		Thermal
40635	LAPINE	230	BPA	RpsORgeo1	RPS Oregon GEO 1		Hourly
45029	BURNS	500	PACW	RpsORsolar1	RPS Oregon SLR 1		Hourly
40585	JOHN DAY	500	BPA	RpsORwind1	RPS Oregon WND 1		Hourly
40585	JOHN DAY	500	BPA	RpsORwind2	RPS Oregon WND 2		Hourly
45327	WALAWALA	230	PACW	RpsWAwind1	RPS Washington WND 1		Hourly
40655	LIBBY	115	BPA	RpsWAwind2_2	RPS Washington WND 2		Hourly
45327	WALAWALA	230	PACW	RpsWAwind2_1	RPS Washington WND 2		Hourly
44052	TDA F1F2	13.8	BPA	DALSF1F2_F2	The Dalles Fishway 2 Wasco OR		Hydro
41111	VANTAGE	230	BPA	Wild Horse	Wild Horse		Hourly
40671	LONGVIEW	230	BPA	LONGVIEW_1	wind Cowlitz County PUD		Hourly
40007	ABERDEEN	115	BPA	ABERDEEN_1	Wynoochee 1 Aberdeen		Hydro
48512	DRYCREEK	230	AVA	RpsWAbio1	RPS Washington BIO 1		Thermal
30015	TABLE MT	500	PG&E_V	RpsCAgeo1	RPS California GEO 1	266	Hourly
30015	TABLE MT	500	PG&E_V	RpsCAbio1	RPS California BIO 1	87	Thermal

Adding Resources

Forty-one generators were added in creating the 'valid starting point' Case 1. They are mostly wind-powered generators (with a few small hydro projects), which already exist or are reasonably expected to be in service by 2017.

Table 16: Table of Generators added in Case 1

Bus No.	Bus Name	Volt - age	Unit No.	Load Area	Name	Long Name	Cap. (MW)	Type
47313	9CWIND 3	34.5	1	BPA	9CWIND 3	wind Nine Canyon 3	33	Hourly
47817	ARLNC W1	34.5	1	PACW	ARLNC W1	Arlington Wind 1	105	Hourly
47818	ARLNC W2	34.5	1	PACW	ARLNC W2	Arlington Wind 2	95	Hourly
47820	BIGHR W1	34.5	1	PACW	BIGHR W1	Big Horn Wind 1	100.5	Hourly
47821	BIGHR W2	34.5	1	PACW	BIGHR W2	Big Horn Wind 2	100.5	Hourly
43073	BULL RUN	6.6	3	PGN	Bull Run 1	Bull Run 1	5.3	Hydro
43073	BULL RUN	6.6	2	PGN	Bull Run 2	Bull Run 2	5.3	Hydro
45566	CMBHIL3	34.5	1	PACW	CMBHIL3	Combine Hills 3	41	Hourly
45126	COPCO 2G	69	1	PACW	COPCO 2G	Copco 2G	27	Hydro
42711	ELECTRON	2.3	1	PSE	ELECTRON 1	Electron 1	3.5	Hydro
42711	ELECTRON	2.3	2	PSE	ELECTRON 2	Electron 2	3.5	Hydro
42711	ELECTRON	2.3	3	PSE	ELECTRON 3	Electron 3	3.5	Hydro
42711	ELECTRON	2.3	4	PSE	ELECTRON 4	Electron 3	9.4	Hydro
43187	FARADAY	11	1	PGN	FARADAY 1	Faraday 1	3	Hydro
43189	FARADAY	13.8	1	PGN	FARADAY 2	Faraday 2	25	Hydro
47829	GDNOE W1	34.5	1	BPA	GDNOE W1	Goodnoe Hills Wind 1	150	Hourly
40484	GREEN PT	13.8	1	BPA	GREEN PT	Green Point 1	46	Hydro
41213	HILLS CR	6.9	1	BPA	HILLS CR 1	Hills Creek 1	17	Hydro
41213	HILLS CR	6.9	2	BPA	HILLS CR 2	Hills Creek 2	17	Hydro
47801	HOPKR W1	34.5	1	BPA	HOPKR W1	Hopkins Ridge Wind 1	75.6	Hourly
47802	HOPKR W2	34.5	1	BPA	HOPKR W2	Hopkins Ridge Wind 2	75.6	Hourly

Continues on next page....

Table 17: Table of Generators added in Case 1 (continued)

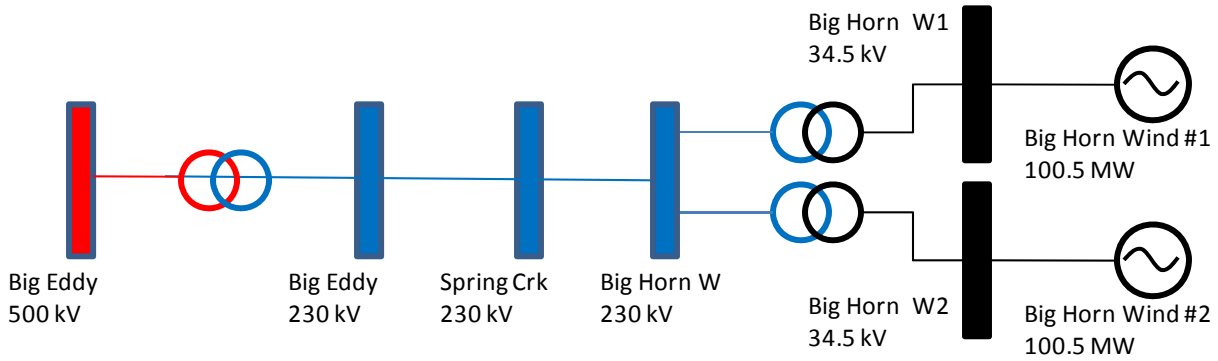
Bus No.	Bus Name	Volt - age	Unit No.	Load Area	Name	Long Name	Cap. (MW)	Type
40584	JOHN DAY	230	1	BPA	KLONDEX1	Klondike Ex 1	100	Hourly
40584	JOHN DAY	230	2	BPA	KLONDEX2	Klondike Ex 2	100	Hourly
47833	KLONE1W4	34.5	1	PACW	KLONE1W4	Klondike East 1 W4	100	Hourly
47834	KLONE2W4	34.5	1	PACW	KLONE2W4	Klondike East 2 W4	100	Hourly
47835	KLONWEW4	34.5	1	PACW	KLONWEW4	Klondike West W4	100	Hourly
47815	LEANJ W1	34.5	1	PACW	LEANJ W1	Leaning Juniper Wind 1	100.5	Hourly
47816	LEANJ W2	34.5	1	PACW	LEANJ W2	Leaning Juniper Wind 2	100.5	Hourly
48253	N LEWIST	115	1	AVA	N LEWIST	North Lewiston Wind	150	Hourly
47841	ORION W2	34.5	1	PGN	ORION W2	Biglow Canyon Wind 2	100	Hourly
47842	ORION W3	34.5	1	PGN	ORION W3	Biglow Canyon Wind 3	100	Hourly
47843	ORION W4	34.5	1	PGN	ORION W4	Biglow Canyon Wind 4	100	Hourly
47844	ORION TP	230	1	PGN	ORIONEX1	Orion Ex Wind 1	100	Hourly
47850	SHPDF W1	34.5	1	BPA	SHPDF W1 Z1	Shepherds Flat Wind 1 Z1	167	Hourly
47850	SHPDF W1	34.5	2	BPA	SHPDF W1 Z2	Shepherds Flat Wind 1 Z2	167	Hourly
47850	SHPDF W1	34.5	3	BPA	SHPDF W1 Z3	Shepherds Flat Wind 1 Z3	167	Hourly
47850	SHPDF W1	34.5	4	BPA	SHPDF W1 Z4	Shepherds Flat Wind 1 Z4	167	Hourly
47850	SHPDF W1	34.5	5	BPA	SHPDF W1 Z5	Shepherds Flat Wind 1 Z4	167	Hourly
42364	WLD HRS1	34.5	1	PSE	WLD HRS1	Wild Horse 1	115	Hourly
42365	WLD HRS2	34.5	1	PSE	WLD HRS2	Wild Horse 2	115	Hourly
47825	WNDYE W1	34.5	1	BPA	WNDYE W1	Windy East Wind 1	150	Hourly
Generators from the TEPPC case for which data were modified								
40671	LONGVIEW	230	2	BPA	MINTFRM_CC1	Mint Farm CC	320.2	Thermal
47840	ORION W1	34.5	1	PGN	ORION W1	Biglow Canyon Wind 1	100	Hourly

Adding Integrating Transmission

The WECC TEPPC PC1 case had buses defined for most of the generators added, as these generators have been under development. It was only necessary to define the generators and

attach them to these buses. The following diagram shows, as an example, the connection of the Big Horn #1 and #2 wind projects to the 500 kV Big Eddy substation.

Figure 7: Interconnection of Big Horn wind projects



Adjusting the Load Forecast

The PC1 case incorporated, for the Northwest, a forecast prepared by the Northwest Power and Conservation Council. That forecast was determined to be inconsistent with other forecasting in the TEPPC case and was updated by WECC to produce a PC1A case. That updated forecast for loads in the Northwest was imported to this project, and then further modified to match BPA's internal forecast. BPA's one-hour non-coincidental forecasted peak load for 2017, including losses, is 35, 476 megawatts. As shown in Table 15, this is 109% of the equivalent PC1A forecast and so Northwest loads were scaled by this factor.

Table 18: Table showing load forecast adjustment in Case 1

Northwest Loads, PC1 Nov12 data (net of losses)	
Coincidental peak (MW)	31,649
Noncoincidental (MW)	32,461
Annual Energy (aMW)	22,036
Ratio of Coincidental to NonCoincidental	
Based on PC1 Nov12 data	97.5%
BPA Forecasted Peak Load in 2017 (including losses)	
Noncoincidental (MW)	35,476
Coincidental (Noncoincidental * 97.5%, MW)	34,589
Ratio of BPA Forecast to PC1 Nov12 data	
Forecast Ration (based on coincidental peak)	109.3%
Forecast for NOS study (including losses)	
Coincidental Peak (MW)	34,589
Annual Energy (aMW)	24,083
NOS Study Loads (net of losses at 3.4%)	
Concidental Peak (MW)	33,413
Annual Energy (aMW)	23,264

Removing Losses from Loads

The GridView model has provision for estimating and removing losses from loads at the beginning of the model's execution. However, it was noticed in early runs that losses in some load areas (essentially, Balancing Authorities) were inconsistent with actual data. It was decided to remove losses exogenously and turn off the loss reduction in GridView. Data from several WECC Base Case power flow studies were used to calculate a loss percentage that was applied to all loads in the WECC.

Table 19: Table showing calculation of loss adjustment based on WECC cases

	Winter			Summer			Autumn			Annual
	17HW1A1 (2007)			18HS1A1 (2008)			10LA1SA1 (2007)			Avg Losses
	Loads	Losses	Loss %	Loads	Losses	Loss %	Loads	Losses	Loss %	(Spr = Aut)
PG & E	17,867.5	507.2	2.8%	32,498.4	1,199.9	3.7%	12,286.1	484.4	3.9%	
So California	17,139.4	283.9	1.7%	27,533.0	461.1	1.7%	13,409.3	526.0	3.9%	
San Diego	4,123.0	79.4	1.9%	5,360.2	118.7	2.2%	2,906.6	43.4	1.5%	
Los Angeles	4,804.3	202.0					3,704.9	255.0	6.9%	
Imperial	786.9	21.3	2.7%	1,422.6	47.5	3.3%	1,252.3	32.9	2.6%	
Total CAISO	**44,721.1**	**1,093.8**	**2.4%**	**66,814.2**	**1,827.2**	**2.7%**	**33,559.2**	**1,341.7**	**4.0%**	**3.3%**
Northwest	33,761.5	1,187.0	3.5%	28,021.0	1,282.5	4.6%	23,821.5	728.9	3.1%	
Total Northwest	**33,761.5**	**1,187.0**	**3.5%**	**28,021.0**	**1,282.5**	**4.6%**	**23,821.5**	**728.9**	**3.1%**	**3.6%**
Nevada	5,575.5	90.2	1.6%	5,870.0	92.7	1.6%	3,297.3	37.7	1.1%	
Sierra	2,675.0	118.2	4.4%	2,675.0	138.2	5.2%	1,020.0	30.3	3.0%	
Idaho	3,167.0	192.0	6.1%	3,761.0	235.0	6.2%	1,840.0	112.0	6.1%	
Montana	1,865.0	97.0	5.2%	1,987.0	109.0	5.5%	1,303.0	104.0	8.0%	
PacifiCorp E	*(defective Excel file)*			10,035.9	402.7	4.0%	5,013.4	213.0	4.2%	
TSGT				70.7	2.6	3.7%				
WACM				1,757.7	64.8	3.7%				
WAPA UM	96.1	2.0	2.1%				60.7	1.0	1.6%	
Total RMPP	**13,378.6**	**499.4**	**3.7%**	**26,157.3**	**1,045.0**	**4.0%**	**12,534.4**	**498.0**	**4.0%**	**3.9%**
PS Colorado	7,428.7	129.1	1.7%	9,485.7	218.5	2.3%	4,159.3	95.1	2.3%	
New Mexico	2,909.2	142.2	4.9%	3,189.2	162.8	5.1%	1,616.5	61.2	3.8%	
El Paso	1,378.5	48.5	3.5%	1,892.2	78.4	4.1%	1,149.8	43.3	3.8%	
WAPA RM	5,269.0	263.4	5.0%	6,041.5	302.1	5.0%	2,513.2	125.7	5.0%	
Arizona	15,931.4	472.7	3.0%							
XCEL				725.7	26.8	3.7%				
PNM				501.4	27.5	5.5%				
DSW				21,462.1	692.9	3.2%	10,385.8	322.5	3.1%	
Total AZNMNV	**32,916.8**	**1,055.9**	**3.2%**	**43,297.8**	**1,509.0**	**3.5%**	**19,824.6**	**647.8**	**3.3%**	**3.3%**
Total US WECC	**124,778.0**	**3,836.1**	**3.1%**	**164,290.3**	**5,663.7**	**3.4%**	**89,739.7**	**3,216.4**	**3.6%**	**3.4%**

Changing Flow-gates and their Limits

BPA's internal analysis and other studies done since the TEPPC PC1 path limits were determined created a need to revise the limits used in this study. Table 2 shows the original and revised limits in this study.

Adding the NOS Resources

BPA Transmission Planning analyzed NOS submissions that resulted in PTSAs and provided specifications on resource characteristics, point of interconnection, and any needed transmission modifications to integrate the resources.

Table 20: Table of NOS resources added in Case 2

Bus No.	Bus Name	Volts (kV)	Load Area	Name	Long Name	Capac. (MW)	Type
41223	LAGOON T	69	BPA	NOS Combine Hill	NOS Combine Hill Wind	82	Hourly
40457	GARRISON	230	BPA	NOS Alternity Wind	NOS Alternity Wind	80	Hourly
40507	HARNEY	115	BPA	NOS Harney Wind	NOS Harney Wind	25	Hourly
40501	HANFORD2	115	BPA	NOS Harvalum Wind	NOS Harvalum Wind	110	Hourly
40537	HIL TOP	230	BPA	NOS Hilltop	Western Renewable Hilltop	10	Hourly
47814	JONESCYN	230	BPA	NOS Jones Canyon	Iberdrola Jones Canyon	200	Hourly
40261	COLUMBIA	230	BPA	NOS Kittitas	Horizon Kittitas Valley	50	Hourly
40584	JOHN DAY	230	BPA	NOS Klondike Wind	NOS Klondike Wind	100	Hourly
49665	NOS GOOS	500	AVA	NOS L Goose Wind 1	NOS Little Goose Wind 1	550	Hourly
49665	NOS GOOS	500	AVA	NOS L Goose Wind 2	NOS Little Goose Wind 2	550	Hourly
40621	LAGRANDE	230	AVA	NOS LaGrande Wind	Horizon Wind LaGrande	150	Hourly
40687	MALIN	500	BPA	NOS Malin Wind 1	Col En Partnrs Malin Wind 1	400	Hourly
40687	MALIN	500	BPA	NOS Malin Wind 2	Col En Partnrs Malin Wind 2	375	Hourly
49962	NOS ASHE	500	BPA	NOS Mercer Wind 1	Mercer Ranch Wind 1	300	Hourly
49962	NOS ASHE	500	BPA	NOS Mercer Wind 2	Mercer Ranch Wind 1	300	Hourly
41402	ROCK CK	230	BPA	NOS Rock Creek Wind	NOS Rock Creek Wind	500	Hourly
49156	NOS RCKY	230	BPA	NOS Rocky Ford Wind	NOS Rocky Ford Wind	100	Hourly
40989	SLATT	500	BPA	NOS Slatt Wind	Horizon Slatt Wind	500	Hourly
41049	TACOMA	230	BPA	NOS Tacoma CoGen	Tacoma CoGen (Based on Ft James)	45	Thermal
40635	LAPINE	230	BPA	NOS Lapine Geoth.	NW Geothermal Lapine	120	Hourly
					Total NOS Capacity (MW)	**4547**	

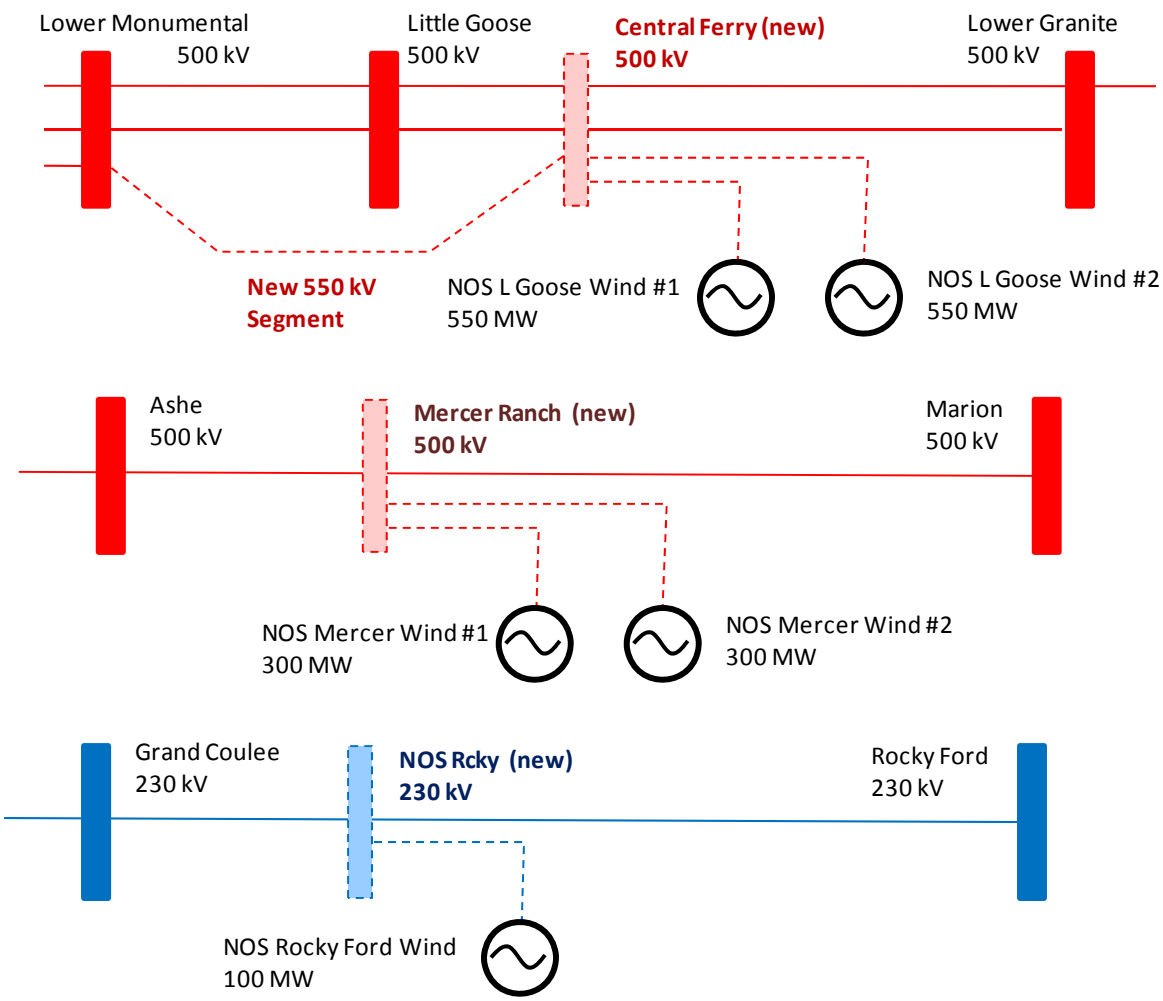
Resources Added and their Characteristics

The NOS generation was aggregated into 20 generators that were added to the GridView data model. The projects were generally given generic names and were connected at appropriate locations, though generally at higher-voltage buses in order to avoid unnecessary modeling of sub-transmission.

Integrating Transmission Added

As mentioned above, most of the NOS generators were connected to existing higher-voltage buses. An example is connection of 775 MW of the Harney wind projects directly to the Malin substation in lieu of modeling a radial 500-kV line from the Harney area. However, to accommodate some of the generating projects added in the NOS portfolio, transmission improvements local to the area of interconnection were required. Three new buses (two 500 kV and one 230 kV) were added.

Figure 8: Diagrams of integrating transmission in Case 2



One 500 kV bus, called Central Ferry, is located between the Little Goose and Lower Granite hydroelectric projects and 'loops in' the two existing circuits between Little Goose and Lower Granite. The second is a 500 kV bus inserted along an existing line between the Ashe R1 substation in Benton County, Washington and the Marion substation near Salem, Oregon and called Mercer Ranch. The third is a 230 kV bus added into the existing line between Grand Coulee substation and the Rocky Ford substation in east-central Washington.

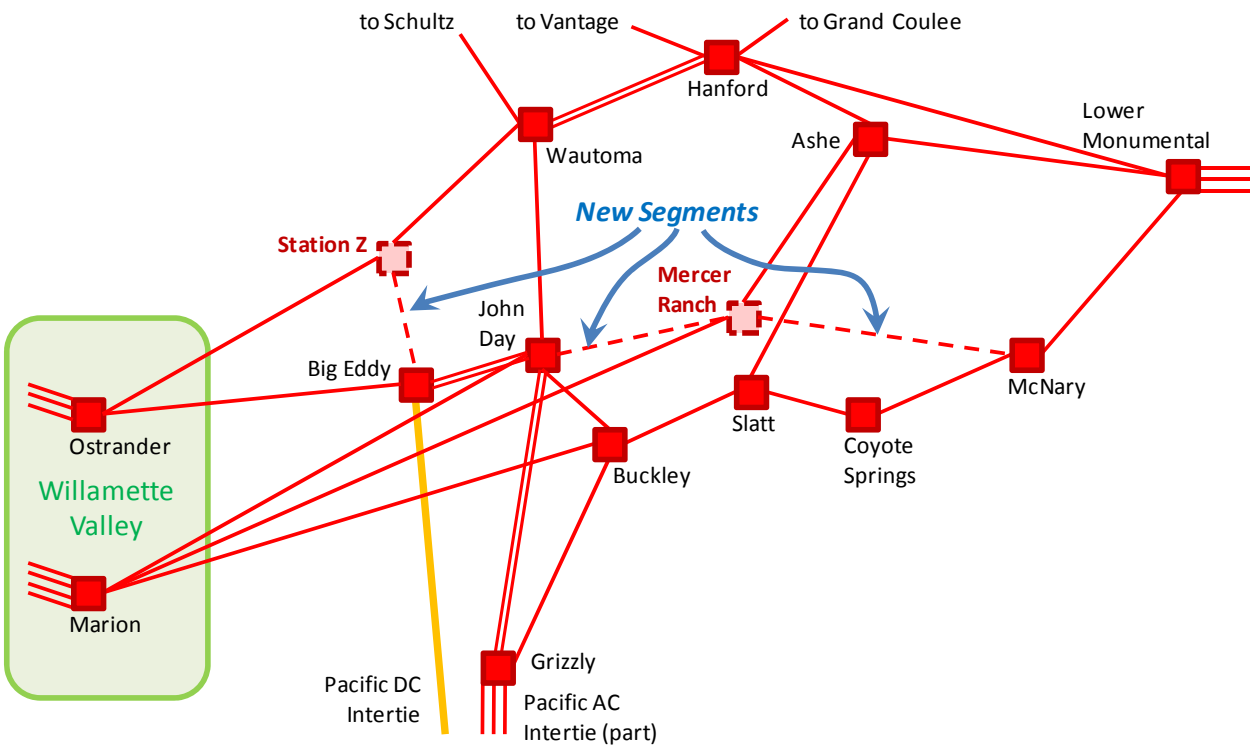
The West-of-McNary Transmission Reinforcements

Transmission Additions

As detailed elsewhere in the BPA 2008 Network Open Season project, the West-of-McNary Reinforcement project centers around the construction of two new substations and two new 500 kV transmission segments.

A 500-kV line is modeled between substations at the McNary and John Day hydroelectric projects along the Lower Columbia River. The line is interconnected with the Mercer Ranch substation added into the Ashe-Marion line and described above.

Figure 9: Diagrams of West of McNary Transmission Reinforcements



Another substation, called Station Z, is modeled along the 500-kV line between the Wautoma substation, near Yakima, Washington, and the Ostrander substation southeast of Portland, Oregon. The new Station Z allows a new 500-kV line to be built between it and the Big Eddy substation southeast of The Dalles, Oregon.

Changes in Flow-gate Limits

In adding the West of McNary transmission reinforcements, the definition and limits for some of the Northwest's internal paths need to be updated. (The base definition, without transmission upgrades, is found in Appendix A.)

The West of McNary path is augmented by the addition of the McNary-Mercer Ranch line segment (see Figure 9). The West of Slatt path is augmented by the Mercer Ranch-John Day line segment, while the West of John Day path adds the Station Z-Big Eddy line segment.

Table 21: Table showing flow-gates and limits changed by WOMR

Internal Paths	Without WoM Project	With WoM Project
North of John Day	7,800	8,400
West of Cascades – North	9,700	9,900
West of Cascades – South	7,500	7,700
West of John Day	2,600	3,550
West of McNary	2,870	4,500
West of Slatt	4,100	5,500

The I-5 Corridor Transmission Reinforcements

The I-5 Corridor reinforcements entail the addition of a new 500-kV bus, called Castle Rock, along the 500-kV line from the Napavine substation near Chehalis, Washington to the Allston substation near Rainier, Oregon. The new substation will allow a new 500-kV line segment to be built from Castle Rock to the Troutdale substation east of Portland, Oregon.

Changes in Flow-gate Limits

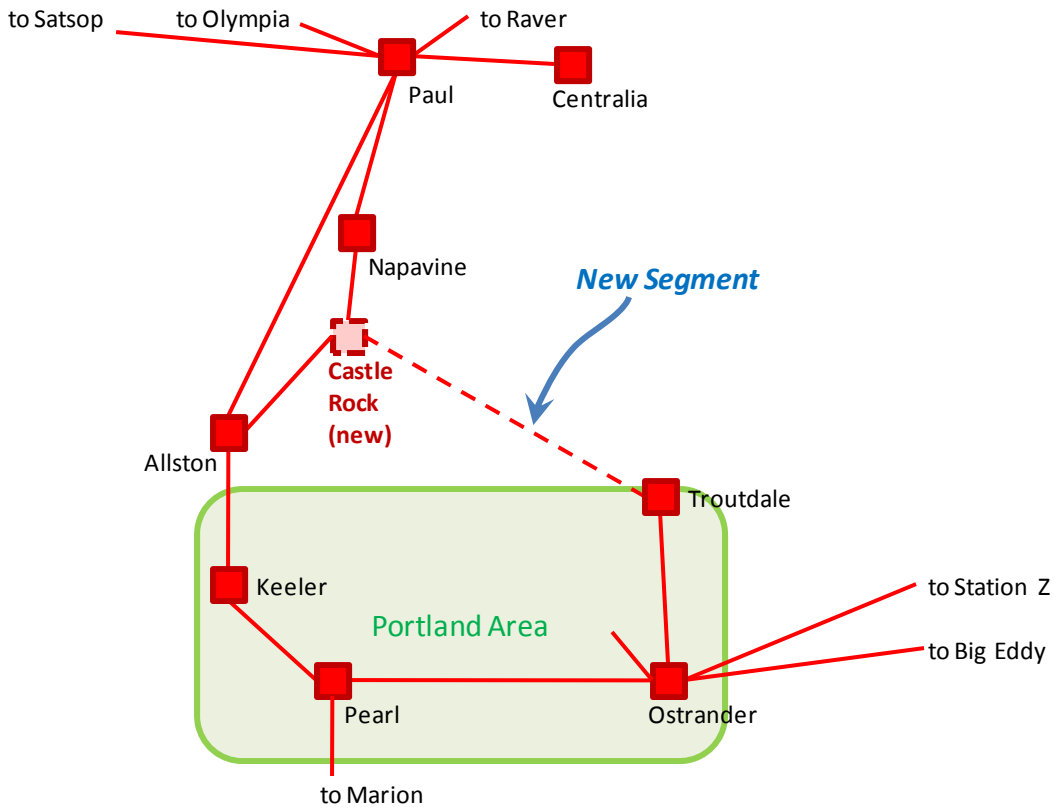
In the definition of the Paul-Allston path, the Napavine-Allston line needs to be replaced by the segment between Castle Rock and Allston. The South of Allston path is modified by the addition of the new Castle Rock-Troutdale segment.

Table 22: Table showing flow-gates and limits changed by I-5 Project

Internal Paths	Without I-5 Project	With I-5 Project
Paul - Allston	2,250	2,990
South of Allston	2,870	3,980

Transmission Additions

Figure 10: Diagram of I-5 Corridor Transmission Reinforcements



Cases without the Southern Oregon Wind Projects

Several of the cases studied in this project were set up with the 800 MW of wind interconnecting at Malin (25 MW is modeled as connected into the 115 kV network, with the remaining 775 MW connected into Malin via a radial line from Harney county) defined as out of service. It was noted in early studies that the injection of this power near the midpoint of the California-Oregon Interties had ramifications on congestion back up into the Northwest; but mitigation of congestion into California is outside the scope of this project. These scenarios included Case 2h, Case 4h, the four emission cases (see below), and Cases 5 and 6.

Cases with CO_2 Emission Costs

Modeling of emission costs in the GridView model is straightforward. A value in dollars per pound is associated with the entire (WECC) system modeled, and is applied to all generators in the Western Interconnection that have a non-zero emission factor for CO_2. This emission factor is specified in pounds per million British thermal units (MMBtu), creating an easy calculation of dollars per MMBtu that is added to the fuel cost.

These cases were derived from Case 2h (the Case 1 'valid starting point', plus NOS resources – less Harney wind) and Case 4h (same as Case 2h, with the addition of the West-of-McNary and I-5

Corridor transmission reinforcements). They are developed by adding an 'Emissions Allowances' record for the entire system (WECC), applicable to carbon dioxide, and with the price set at $0.01/lb (equivalent to $20/ton), and at $0.025/lb (equivalent to $50/ton). The model is then instructed, in the Simulation Configuration dialog, to use a Calculated Emission Cost Model for the Entire System.

While GridView calculates the emission cost in dollars per pound, it is important to keep in mind that GridView output data are reported in metric tons, also referred to as tonnes, and equal to 1,000 kilograms, or 2,204.6 lbs.

Appendix A: Definition of Reported Paths

Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit
Internal Interfaces							
North of Hanford	40957	SCHULTZ	→	41138	WAUTOMA	500	1
	40287	COULEE	→	40499	HANFORD	500	1
	40499	HANFORD	←	41113	VANTAGE	500	1
North of John Day	41401	ROCK CK	←	41138	WAUTOMA	500	1
	40821	PAUL	←	40869	RAVER	500	1
	40809	OSTRNDER	←	41138	WAUTOMA	500	1
	40723	MCNARY	←	40917	SACJWA T	500	1
	40061	ASHE	→	40062	ASHE R1	500	2
	40061	ASHE	→	40989	SLATT	500	1
Paul - Allston	40045	ALLSTON	←	40821	PAUL	500	2
	40045	ALLSTON	←	40774	NAPAVINE	500	1
Raver - Paul	40821	PAUL	←	40869	RAVER	500	1
South of Allston	40045	ALLSTON	→	40601	KEELER	500	1
	40899	ROSS	←	41161	WOODLAND	230	1
	43229	HARBORTN	←	43601	TROJAN 2	230	1
	43541	ST MARYS	←	43599	TROJAN 1	230	1
	45011	ASTOR TP	→	45275	SEASIDE	115	1
	47095	VIEW TAP	←	45201	MERWIN	115	1
	40041	ALLSTON	→	43776	RAINIER#	115	1
West of Cascades - North	40869	RAVER	←	40957	SCHULTZ	500	3
	42312	CASCADEP	←	46831	ROCKYRH1	230	1
	40869	RAVER	←	40957	SCHULTZ	500	4
	40869	RAVER	←	40957	SCHULTZ	500	1
	40691	MAPLE VL	←	40891	ROCKY RH	345	1
	40381	ECHOLAKE	←	40957	SCHULTZ	500	1
	40285	COULEE	→	40795	OLYMPIA	300	1
	40261	COLUMBIA	→	40303	COVINGTN	230	1
	40233	CHIEF JO	→	40749	MONROE	500	1
	40225	CHIEF J4	→	40994	SNOHOMS4	345	4
	40223	CHIEF J3	→	40993	SNOHOMS3	345	3
	42361	WIND RDG	←	46169	WANAPUM	230	1

Continues on next page…

Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit
Internal Interfaces (Continued)							
West of Cascades - South	40585	JOHN DAY	→	40699	MARION	500	1
	41343	BIGEDDY3	→	43313	MCLOUGLN	230	1
	47814	JONESCYN	→	41079	TMBLCR T	230	1
	41342	BIGEDDY2	→	40213	CHEMAWA	230	1
	41341	BIGEDDY1	→	40813	PARKDALE	230	1
	40721	MCNARY	→	40901	ROSS	345	1
	40155	BUCKLEY	→	40699	MARION	500	1
	40111	BIG EDDY	→	40809	OSTRNDER	500	1
	40061	ASHE	→	40062	ASHE R1	500	2
	40039	ALFALFA	→	40141	N BONNVL	230	1
	40809	OSTRNDER	←	41138	WAUTOMA	500	1
West of John Day	40111	BIG EDDY	←	40585	JOHN DAY	500	1
	40111	BIG EDDY	←	40585	JOHN DAY	500	2
West of McNary	40939	SANTIAM	←	41079	TMBLCR T	230	1
	40721	MCNARY	→	40901	ROSS	345	1
	43123	COYOTE	→	40989	SLATT	500	1
	40549	HORSE HV	←	41351	MCNRY S1	230	1
West of Slatt	40155	BUCKLEY	←	40989	SLATT	500	1
	40585	JOHN DAY	←	40989	SLATT	500	1
External Interfaces							
Bridger West	60085	BRIDGER	→	60084	3MIKNOLL	345	1
	60085	BRIDGER	→	60060	BORAH	345	1
	60085	BRIDGER	→	60190	KINPORT	345	1
CA-OR Intertie (COI)	40687	MALIN	→	30005	ROUND MT	500	1
	40687	MALIN	→	30005	ROUND MT	500	2
	45035	CAPTJACK	→	30020	OLINDA	500	1
Idaho - Northwest	60150	HELLSCYN	→	45103	HURICANE	230	1
	45029	BURNS	←	60500	MELBA	500	1
	45029	BURNS	←	60240	MIDPOINT	500	1
	61826	HINES	→	40507	HARNEY	115	1
	48197	LOLO	←	60278	IMNAHA	230	1
	60192	LADD	→	40621	LAGRANDE	230	1
Continues on next page…							

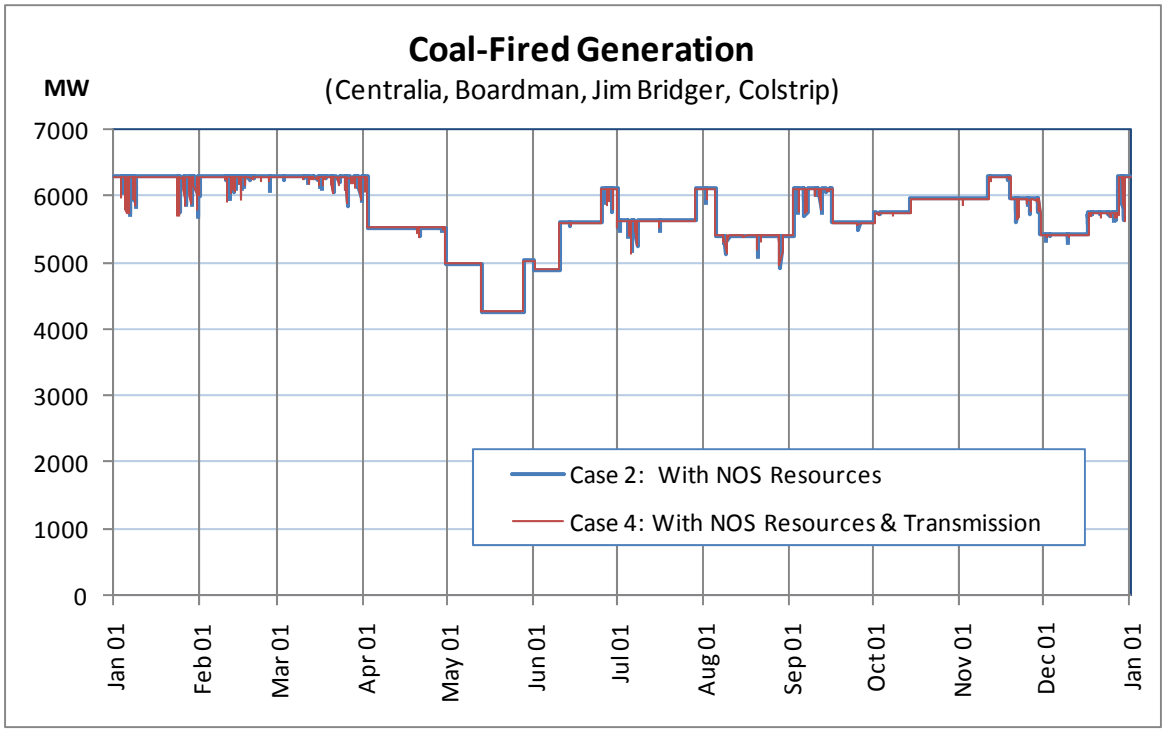
Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit
External Interfaces (Continued)							
Midpoint - Summer Lake	45029	BURNS	←	60240	MIDPOINT	500	1
	45029	BURNS	←	60500	MELBA	500	1
Montana - Northwest	40457	GARRISON	←	62072	OVANDO	230	1
	40867	RATTLE S	←	62009	RATTLE S	161	1
	40453	GAR2EAST	→	40459	GARRISON	500	1
	62004	MILL CRK	→	40457	GARRISON	230	1
	40391	ELMO	←	62066	KERR	115	1
	40451	GAR1EAST	→	40459	GARRISON	500	1
	48055	BURKAVAB	→	48051	BURKE	115	1
	62339	ANA BPA	→	40457	GARRISON	230	1
	40551	HOT SPR	←	62344	PLACIDLK	230	1
	48053	BURKAVAA	→	48051	BURKE	115	1
NW to Canada East BC	50822	NLYPHS	←	40145	BOUNDARY	230	1
	52219	WAN230	←	40145	BOUNDARY	230	1
NW to Canada West BC	50194	ING500	←	40323	CUSTER W	500	1
	50194	ING500	←	40323	CUSTER W	500	2
Pacific DC Intertie (PDCI)	40111	BIG EDDY	→	41312	CELILO2	500	2
	41341	BIGEDDY1	→	41313	CELILO3	230	3
	41343	BIGEDDY3	→	41314	CELILO4	230	4
	40111	BIG EDDY	→	41311	CELILO1	500	1
Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit

Appendix B: Sample Operation of Fossil-Fueled Generators

A common problem with hourly production cost simulation models is the difficulty in adequately representing the actual operation of coal-fired generating plants. The two charts below illustrate this issue.

The combined output of eleven generating units whose power is largely scheduled to the Northwest (four at Jim Bridger and Colstrip, two at Centralia and one at Boardman), is generally flat, with step-wise reductions during periods when one or more generators if off for maintenance (forced outages are not modeled in this study).

The interaction of wind generation, loads and substantial unregulated hydrogeneration provides a net load for thermal generation that is sufficiently variable to require the occasional reduction of coal-fired output. While actual operations would likely keep the output more constant, the simulation by GridView is reasonable.

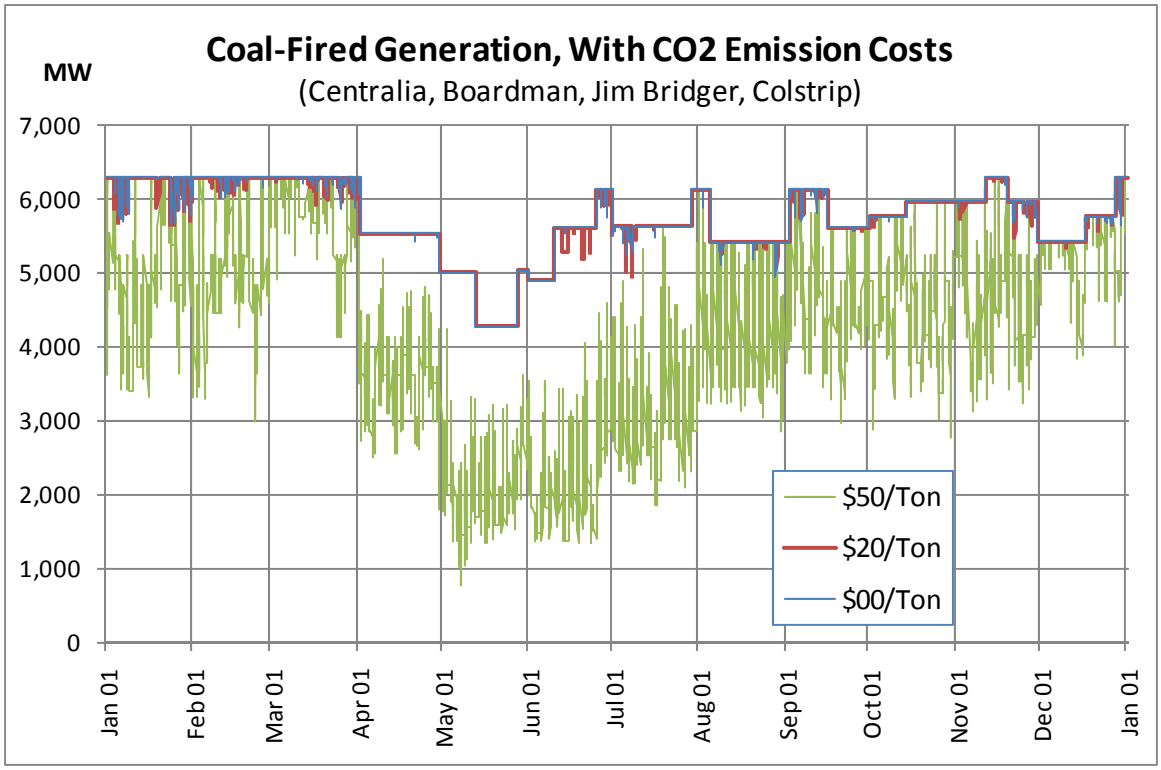


In the case of high CO_2 costs, however, the coal units are more expensive to operate than natural gas-fired combined cycle combustion turbine projects, and so are forced to reduce their generation whenever the sum of output from hydrogeneration, low-cost renewables and combined cycle projects are sufficient to meet loads and export markets.

While this operation is 'unnatural' in the Western Interconnection, coal-fired generators have been cycled on a daily basis in other markets, such as the United Kingdom. It is not possible to

predict how owners of coal-fired generation would operate their units in a market where they were on the margin.

GridView minimizes production costs based on the operating data and prices provided to the model, and parameters such as minimum up and down times and startup costs have been developed to produce a dispatch similar to current operations. For example, Jim Bridger units are assigned a minimum up time of 12 hours and a minimum down time of 48 hours. This means that GridView will not turn the unit on unless it can run economically for 12 hours and will not turn it off unless it will be left off for at least 48 hours. While these durations are believed to be physically possible, unit owners may adopt policies that decline to operate the units with the many cycles that would occur in a high CO_2-cost market.



Appendix C: Northwest Wind Projects & Wind Shapes

Generator Name	Commit-ment Shape	Commit-ment Multiplier	Dispatch Shape Name	Dispatch Multiplier	Region	NWPP Integrated (MW)
9CWIND 1_1	OR2	0.261	OR2	0.261	NWPP	26.1
9CWIND 2_1	OR2	0.261	OR2	0.261	NWPP	26.1
9CWIND 3_1	OR2	0.330	OR2	0.330	DUMMY	-
Arlington/Leaning J.	OR1	1.000	OR1	1.000	NWPP	100.0
ARLNC W1	OR1	1.050	OR1	1.050	DUMMY	-
Big Horn	WA4	2.499	WA4	2.499	NWPP	249.9
BIGHR W1	WA4	1.005	WA4	1.005	NWPP	100.5
BIGHR W2	WA4	1.005	WA4	1.005	DUMMY	-
CMBHIL3	OR2	0.410	OR2	0.410	DUMMY	-
CONWIND_1	OR1	0.500	OR1	0.500	NWPP	50.0
GDNOE W1	OR1	1.500	OR1	1.500	DUMMY	-
Hopkins Ridge	WA3	1.499	WA3	1.499	NWPP	149.9
HOPKR W1	WA3	0.756	WA3	0.756	DUMMY	-
HOPKR W2	WA3	0.756	WA3	0.756	DUMMY	-
Klodike 2	OR1	0.750	OR1	0.750	NWPP	75.0
Klodike 3/Orion	OR1	2.999	OR1	2.999	NWPP	299.9
KLOND W1_1	OR1	0.125	OR1	0.125	NWPP	12.5
KLOND W1_2	OR1	0.125	OR1	0.125	NWPP	12.5
KLOND W2_1	OR1	0.255	OR1	0.255	NWPP	25.5
KLONDEX1	OR1	1.000	OR1	1.000	NWPP	100.0
KLONDEX2	OR1	1.000	OR1	1.000	DUMMY	-
KLONE1W4	OR1	1.000	OR1	1.000	DUMMY	-
KLONE2W4	OR1	1.000	OR1	1.000	DUMMY	-
KLONWEW4	OR1	1.000	OR1	1.000	DUMMY	-
LEANJ W1	OR1	1.005	OR1	1.005	DUMMY	-
LEANJ W2	OR1	1.005	OR1	1.005	DUMMY	-
MARENGO	WA3	1.399	WA3	1.399	NWPP	139.9
N LEWIST	WA3	1.500	WA3	1.500	DUMMY	-
Continues….						

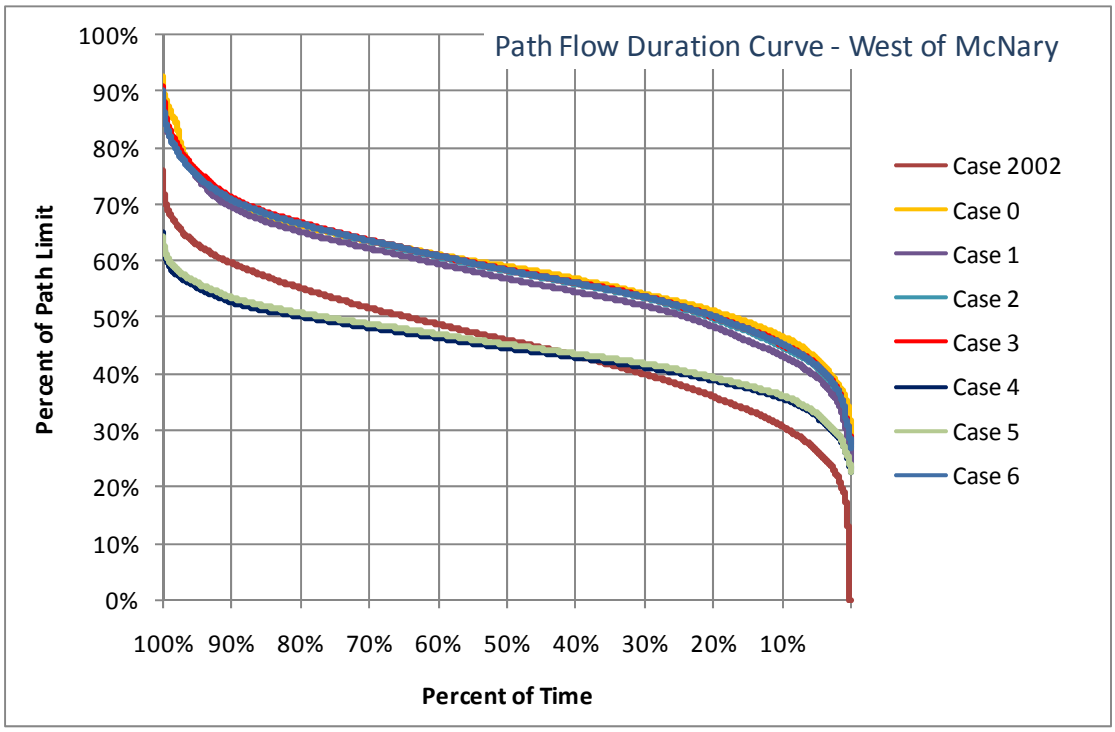
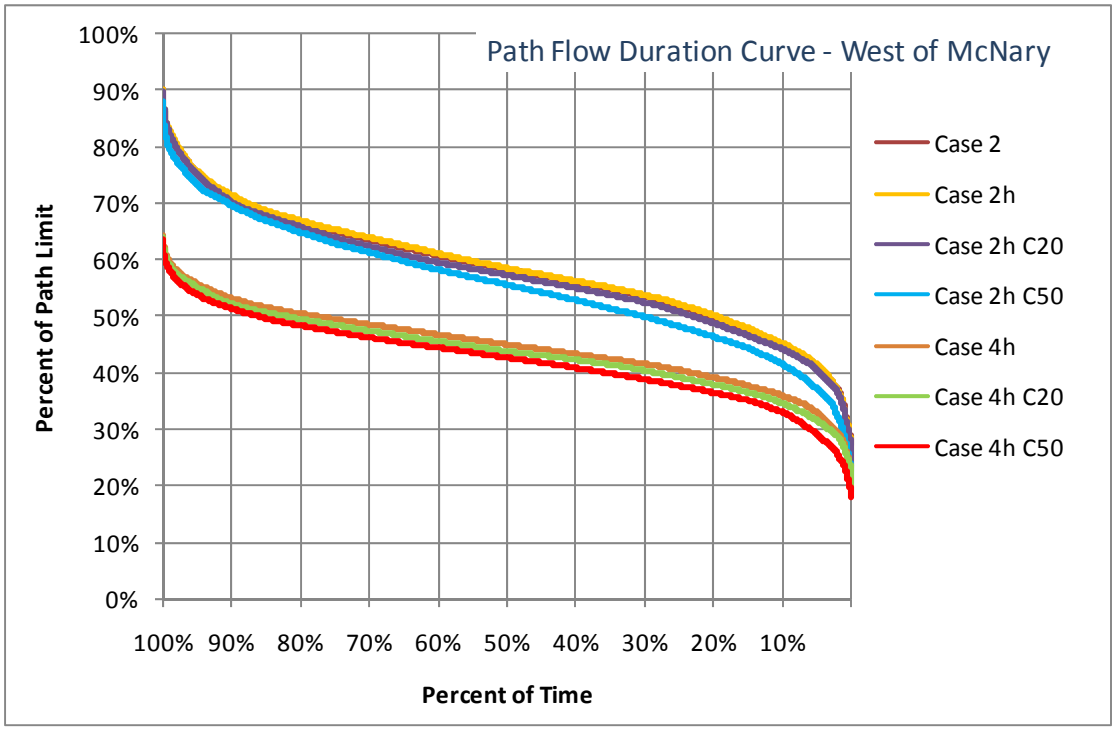
Generator Name	Commit-ment Shape	Commit-ment Multiplier	Dispatch Shape Name	Dispatch Multiplier	Region	NWPP Integrated
NOS Alternity Wind	MT2	0.800	MT2	0.800	DUMMY	-
NOS Combine Hill	OR2	0.620	OR2	0.620	DUMMY	-
NOS Harney Wind	OR5	0.250	OR5	0.250	DUMMY	-
NOS Harvalum Wind	OR2	1.100	OR2	1.100	DUMMY	-
NOS Jones Canyon	OR1	2.000	OR1	2.000	DUMMY	-
NOS Kittitas	WA2	0.500	WA2	0.500	DUMMY	-
NOS Klondike Wind	OR1	1.000	OR1	1.000	NWPP	100.0
NOS L Goose Wind 1	WA3	5.500	WA3	5.500	DUMMY	-
NOS L Goose Wind 2	WA3	5.500	WA3	5.500	DUMMY	-
NOS LaGrande Wind	OR3	1.500	OR3	1.500	DUMMY	-
NOS Malin Wind 1	OR5	4.000	OR5	4.000	DUMMY	-
NOS Malin Wind 2	OR5	3.750	OR5	3.750	DUMMY	-
NOS Mercer Wind 1	OR2	3.000	OR2	3.000	DUMMY	-
NOS Mercer Wind 2	OR2	3.000	OR2	3.000	DUMMY	-
NOS Rock Creek Wind	WA4	5.000	WA4	5.000	DUMMY	-
NOS Rocky Ford Wind	WA2	1.000	WA2	1.000	DUMMY	-
NOS Slatt Wind	OR1	5.000	OR1	5.000	NWPP	500.0
ORION W1	OR1	1.259	OR1	1.259	NWPP	125.9
ORION W2	OR1	1.000	OR1	1.000	DUMMY	-
ORION W3	OR1	1.000	OR1	1.000	DUMMY	-
ORION W4	OR1	1.000	OR1	1.000	NWPP	100.0
ORIONEX1	OR1	1.000	OR1	1.000	DUMMY	-
SHPDF W1 Z1	OR1	1.670	OR1	1.670	DUMMY	-
SHPDF W1_Z2	OR1	1.670	OR1	1.670	NWPP	167.0
SHPDF W1_Z3	OR1	1.670	OR1	1.670	DUMMY	-
SHPDF W1_Z4	OR1	1.670	OR1	1.670	DUMMY	-
SHPDF W1_Z5	OR1	1.670	OR1	1.670	DUMMY	-
STATL W1_1	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W1_2	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W1_3	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W1_4	OR2	0.250	OR2	0.250	NWPP	25.0
Continues….						

Generator Name	Commit-ment Shape	Commit-ment Multiplier	Dispatch Shape Name	Dispatch Multiplier	Region	NWPP Integrated
STATL W2_1	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_2	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_3	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_4	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_5	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_6	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_7	OR2	0.250	OR2	0.250	NWPP	25.0
STATL W2_8	OR2	0.250	OR2	0.250	NWPP	25.0
VANSYCLE_1	OR2	0.250	OR2	0.250	NWPP	25.0
WHTCK W1	WA4	1.999	WA4	1.999	NWPP	199.9
WLD HRS1	WA2	1.150	WA2	1.150	NWPP	115.0
WLD HRS2	WA2	1.150	WA2	1.150	DUMMY	-
WNDYE W1	OR1	1.500	OR1	1.500	DUMMY	-
Total Load-Integrated Wind-Powered Generation						**3,000.4**

Appendix D: Proportional Load-Following Hydrogeneration K-Factors

This table shows the K-Factors used in this study for Northwest hydroelectric projects. They are taken from a Microsoft Excel workbook entitled 'PLF090208.xls' provided by BPA. Most other hydro-electric projects in the study use fixed hourly hydrogeneration based on 2002 actual values.

Project Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary	3.97	4.22	3.87	3.00	3.00	3.00	3.00	3.48	3.77	3.60	4.17	4.89
Brownlee	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Cabinet Gorge	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Chief Joseph	3.55	3.51	4.58	3.00	3.00	3.00	3.00	3.00	3.80	3.50	3.42	3.83
Grand Coulee	4.05	4.18	5.62	3.13	3.21	3.00	3.00	3.02	4.48	3.75	3.93	4.33
Ice Harbor	2.39	2.87	0.88	2.40	3.29	3.18	2.42	2.23	2.27	0.91	1.12	3.32
John Day	1.52	1.52	0.84	1.16	0.92	1.08	1.12	1.24	1.33	1.35	1.40	1.41
Little Goose	2.63	3.41	0.79	1.77	1.86	1.19	1.53	1.08	1.65	0.57	0.81	3.67
Lower Granite	2.30	3.08	0.64	1.49	1.00	1.00	1.00	1.00	1.20	0.45	0.66	3.62
McNary	1.19	1.19	0.59	1.35	0.69	0.70	0.70	0.70	0.70	1.05	1.06	0.85
Mossyrock	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Noxon Rapids	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Oxbow	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Rock Island	1.34	0.86	1.93	1.13	1.12	1.00	1.00	2.13	2.44	2.14	1.31	1.70
Rocky Reach	1.65	1.24	2.26	1.15	0.86	1.00	1.00	2.14	2.52	2.30	1.63	2.12
Round Butte	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
The Dalles	1.34	1.43	0.84	0.74	0.74	0.88	0.75	0.58	1.31	1.23	1.29	1.38
Wells	2.68	2.63	3.33	1.55	1.40	1.50	1.50	2.31	2.76	2.93	2.11	3.25
Yale	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00

Appendix E: Path Flow Duration Curves for Reported Paths

Path flow duration curves (such as those below) are provided in a separate document, entitled "BPA 2008 Network Open Season – CPS Annex 2008-12-30."