The True Cost of Coal

Fully accounting for coal-fired electricity use in the 7th Northwest Power and Conservation Plan

A NW Energy Coalition issue paper

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NW Energy Coalition
for a clean and affordable energy future

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The report's findings and recommendations are those of the NW Energy Coalition alone and do not necessarily represent the views of any reviewer.

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– NW Energy Coalition, July 2015

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Executive summary

Rising costs for running coal-fired power plants are driving an electricity industry transition away from coal. Since 2010, nearly 20% of the nation's coal fleet, 61,000 megawatts of capacity, has been slated for retirement or conversion due to U.S. Environmental Protection Administration policies and other financial considerations.[1] The future of coal-fired generating plants serving the Northwest is a critical component of both near- and long-term electric system planning. The Northwest Power and Conservation Council must comprehensively consider the high capital costs of coal-plant upgrades while developing the region's next long-term resource plan.

The Council's modeling approach for its 7th Northwest Power and Conservation Plan inadequately represent the costs of maintaining existing coal-fired generation:

1. Its regional portfolio model (RPM) does not incorporate capital costs for existing coal-fired generating plants
2. Its supplemental analysis of coal capital costs fails to fully reflect those costs.
3. Its analysis completely omits several coal generating units that serve Northwest customers and that Northwest families and businesses pay for in their electric rates.

Although its modeling does not incorporate coal generator capital costs, the Council has released supplemental information on environmental costs associated with the coal plants that are included in the plan. This information, however, understates some of these costs. First, all the coal plants serving the Northwest are at least 30 years old (Valmy, Colstrip units 3 and 4, and Wyodak are youngest, entering service in the early 1980s); all face major reconstruction or renovation costs within the 7th Power Plan's time horizon.

Second, the Council's cost estimate for retrofitting Jim Bridger units 1 and 2 appears too low by up to $100 million. The Council does not consider the likelihood of a major upgrade at Colstrip units 1 and 2 in the 2020–2027 time frame to comply with the EPA regional haze rule, thus overlooking about $150 million in costs. The Council also failed to provide levelized costs without the upgrades, making it difficult to compare the added emission costs to the plants' current ongoing costs.

Ignoring "out-of-region" coal plants' role in serving Northwest load is an historical shortcoming of Council power plans. Strong operational, regulatory and policy ties

[1] American Coalition for Clean Coal Electricity, "Coal Unit Shutdowns as of January 25, 2015.," http://www.americaspower.org/sites/default/files/Coal%20Unit%20Retirements%20JANUARY%2025%202015.pdf

between these out-of-region plants and the Northwest region demand including these resources in the planning process. These plants face hundreds of millions in costs to comply with environmental regulations, a portion of which will be paid Northwest billpayers. Clearly, these customers have a significant stake in the Council's decisions about resources lying outside Council's planning footprint; considering these resources and their environmental costs will create a stronger, more accurate power plan.

Beyond the 7th Plan, getting the costs of Northwest-serving coal generation right is important for analyzing compliance options for the EPA's Clean Power Plan. Many stakeholders expect the Council to help them evaluate compliance approaches and want the Council to model a Clean Power Plan-compliant scenario in the 7th Plan process. Accurate and full accounting of coal generating costs is essential to these analyses.

The Council is now crafting the next plan for meeting Northwest electric needs in the most economic and reliable way. It can build a more robust analytical process by more carefully considering these issues. Specifically, the NW Energy Coalition urges the Council to:

- Fully account for and model the environmental costs of "in-region" coal generating plants.
- Incorporate "out-of-region" plants and their environmental costs in power plan analyses.
- Appropriately reflect information for in- and out-of -region generators in all information relevant to EPA's Clean Power Plan.

These actions will lead to a better evaluation of regional power system costs and risks in 7th Northwest Power and Conservation Plan.

I. Introduction

Every five years the Northwest Power and Conservation Council reassesses the region's long-term electricity needs and builds a power plan aimed at assuring the region an adequate, efficient, economical, and reliable power system. Utilities, regulators and energy planners use the Council's power plans when assessing the costs and risks of resources to meet their customers' loads.

Like many regions, the Pacific Northwest faces difficult resource decisions in the coming years. While hydro has historically dominated the region's resource mix, coal-fired generation has provided considerable energy to Northwest consumers. Many of these coal plants (and their power output) are owned by Northwest utilities, but are located remotely at mine-mouth coal facilities and provide baseload generation to multi-state service areas. EPA-enforced federal environmental regulations such as regional haze, the mercury and air toxics standards (MATS) and the pending Clean Power Plan add to the environmental compliance costs to be borne by the owners of these coal-fired facilities and their customers. The complicated, interconnected nature of the region and the inter-regional electric grid makes integrating these environmental costs into the power a challenge. But it is of the upmost importance given the Council's statutory responsibilities for the natural environment.

This paper critiques and supplements recent Council analyses of the environmental costs for in- and out-of-region coal resources to provide a more accurate picture of the economic risk the region may face by continuing coal plant operations as compared to other technologies. In its April 24, 2015, technical support document, *Regulatory Compliance Issues Affecting Existing Northwest Generating Plants,*[2] the Council identifies environmental regulations that will force significant capital investment in coal resources. The document assesses the compliance obligations and the potential capital and operating costs for plants already included in power plan analysis.

In the following pages, we review these environmental obligations, corresponding emissions reduction retrofit costs, and raise a few concerns with the Council's modeling and investigation. Then we widen the analytical footprint and investigate emissions-related retrofit costs for coal-fired plants omitted from the Council's work even though they serve Northwest customers and are reflected in their electric bills. We conclude with key policy recommendations to inform the Council's 7th Power Plan.

> **■ A note on methodology**
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> This analysis uses publicly available documents to independently assess the costs of new environmental controls, with a focus on capital expenditures, for Pacific Northwest plants, including out-of-region plants that Northwest electric customers rely on and support when paying their bills. To assess the scale and scope of potential upgrade costs for these coal-fired resources, we rely primarily on the various utilities' integrated reporting plans (IRPs) as well as financial reporting documents (10-Ks).

[2] http://www.nwcouncil.org/media/7149177/draft7p_regulatorycomplianceandcosts_042415.pdf

IRPs are required by various jurisdictions. Each results from a utility-led evaluation of its current and future resource portfolios to ensure reliable and least-cost electric service. After a number of portfolios and scenarios are considered, a preferred portfolio emerges. IRPs are forward-looking, with a time horizon that may align with the Council's planning process.

PacifiCorp's draft 2015 IRP, published in March 2015, is the source for much of the information in this paper. Company 10-Ks also have proven useful. Financial reporting requires disclosures about risk and the environmental regulations pose significant future risk to plant operations.

II. The 7th Power Plan modeling of environmental regulations

The 7th Power Plan will identify the optimal mix of power generation and energy conservation to economically and reliably meet Pacific Northwest's energy needs for the next 20 years. The Council will identify least-cost/least-risk strategies through significant scenario analysis and modeling efforts. While the Council employs numerous models to develop the power plan, the regional portfolio model (RPM) is most relevant to resource cost/benefit assessment. The RPM develops and identifies resource portfolios and strategies based on the region's needs (i.e. load, policy directive), while also considering the costs and potential for new energy efficiency and generation. The RPM reviews many iterations of potential resource plans, considering risks, costs and the tradeoffs between the two.

The RPM model seeks to minimize the average cost to serve the region's load over a 20-year time horizon, considering a specific (and predefined) set of uncertain futures. In performing this optimization, the model considers many costs and factors. However, as it relates to the consideration of environmental costs and benefits, two limitations of the modeling framework may lead to a critical understatement of the costs. One is omitting environmental capital expenditures; the other is restricting the Northwest load-serving resources the model includes.

These limitations are described below and expanded upon in following pages.

Environmental costs for existing, "in-region" Pacific Northwest resources: For existing generation resources located in the regional footprint, the RPM and power plan development process consider only the variable costs associated with a unit's operation. Capital costs that may occur during the generator's asset life, such as capital improvements needed to maintain or meet environmental regulations, are included in the model but do not affect the RPM's selection of which units to operate. Major power plant retrofit and renovation can cost hundreds of millions or even billions of dollars. It would be more appropriate to consistently account for environmental costs for all resources in the plan. This is particularly pertinent for existing coal resources included in the plan, because including these costs would allow the region to understand the significant investments associated with continued operation of plants requiring emission retrofit upgrades. If these costs are not accounted for, the 7th Power Plan will not adequately weigh the costs and risks when determining the most cost effective portfolio to serve Pacific Northwest customers.

Environmental cost for "out-of-region" resources: The RPM and the power plan development process is limited to existing resources physically located inside the region's footprint -- all generation in Montana, Idaho, Oregon and Washington, and a handful of generators in Nevada and Wyoming. This accounting is too narrow considering the interconnected nature of Northwest grid operations, regulation and policy strategy. The Council should better account for the interconnected nature of the Northwest region's power system with the rest of the Western grid and include environmental costs (and if applicable, benefits) of out-of-region generation in the RPM and power plan development. Billpayers in the region are served by and pay for many resources omitted from the Council's modeling. Including all plants owned by utilities serving the region or paid for under long-term contracts by the region would provide a more comprehensive and accurate accounting of resource and system costs.

III. Environmental regulations and potential compliance costs

Owners of coal-fired generation resources face numerous pollution control upgrades and cooling system modifications to meet more stringent environmental regulations and water supply constraints. The regulations can require upfront capital expenditures for new equipment, and many will increase operating and maintenance costs. Some upgrades increase parasitic load and reduce the net energy the resources can produce. The Council's technical support document on this issue provides extensive detail on the environmental regulations that can affect coal-fired resources.

We briefly summarize the same environmental regulations below.[3]

Regional haze: The EPA's 1999 regional haze rule, which aims to improve air quality in national parks and wilderness areas, requires best available retrofit technology (BART) on many coal plants in the West to reduce emissions of particulates, nitrogen oxides (NO_X) and sulfur dioxide. The rule requires reasonable progress over time, with a goal for restored visibility by 2064. States are required to file periodic updates, making this an ongoing compliance issue. This is currently one of the primary environmental cost drivers for coal plants in the West.

Mercury and air toxics standards (MATS): This 2011 EPA rule established a standard for mercury and other air toxics emissions from power plants. The compliance deadline is April 2015, so the environmental upgrades required by this rule have mostly been completed, although some one-year extensions were granted to finish installing the required equipment. In June 2015, the U.S. Supreme Court ruled that costs must be factored into the standards-setting process and referred the details to lower courts.

[3] EPA websites. See, for example, http://www.epa.gov/visibility/program.html for Regional Haze and http://www.epa.gov/mats/ for MATS. The Council's paper details the changing regulatory standards that will affect nuclear plants, hydropower operations, the release of fugitive methane in natural gas operations, and the protection of wildlife at certain renewable energy plants. This paper, since its focus is coal-fired generation, did not review or consider those regulations.

Cooling water intake structures rule: This EPA rule, issued under section 316(b) of the Clean Water Act, was finalized in May 2014 and became effective in October 2014. The rule governs the design and operation of cooling water intake structures. The standard must be met as soon as possible, but no later than eight years after the rule's effective date. Power plants that withdraw 2 million gallons per day must choose among seven methods for reducing harm to fish and other aquatic organisms. Power plants that withdraw more than 125 million gallons per day must determine the best site-specific controls for reducing the number of aquatic organisms being drawn into the facilities. As yet, power plant operators are not publicly estimating costs to comply with this rule.

Coal combustion residuals (CCRs): This EPA rule governs the waste products of coal combustion, primarily coal ash. The rule was final in December 2014, and coal plant operators have not publicly quantified the effects of this new regulation. Compliance might mean upgrades or closures of landfills or surface impoundments used for coal ash.

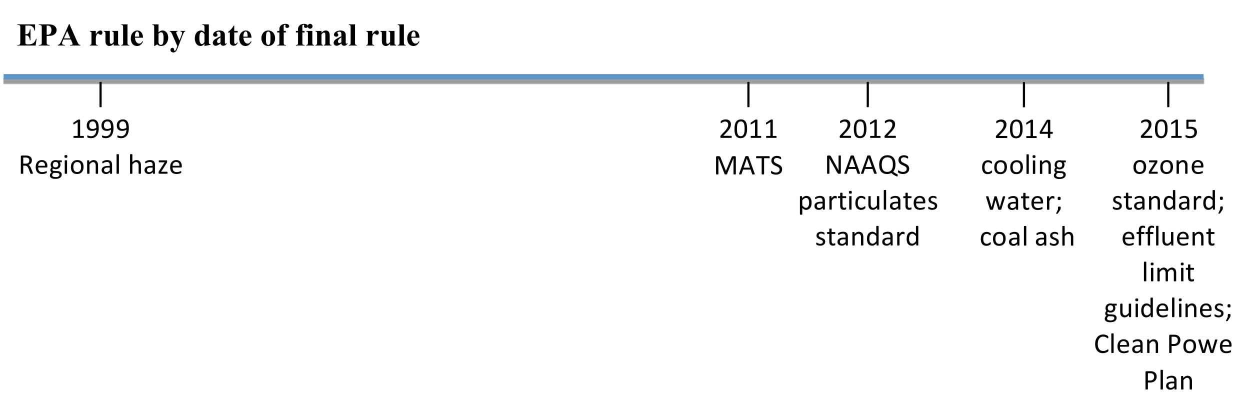
Effluent limit guidelines (ELG): This EPA rule is currently in draft form, with a final rule expected in September 2015. The rule will govern the discharge of toxic pollutants by steam-electric generators into rivers and streams.

National ambient air quality standards (NAAQS): The Clean Air Act requires EPA to periodically review and revise emissions standards for six "criteria" pollutants. The December 2012 update changes the particulates standard. A new ozone standard is expected in October 2015. Ground-level ozone is formed by chemical reactions, with NO_X a main precursor emission. As EPA designates non-attainment areas and states start work on implementation plans to comply with the revised NAAQS, some coal plants may need additional environmental upgrades.

Clean Power Plan: This draft EPA rule seeks to regulate greenhouse gas emissions from existing power plants under section 111(d) of the Clean Air Act. The draft rule was issued in June 2014 and a final rule is expected in summer 2015. It is anticipated the EPA will release the EPA 111(b) rule, effecting only new qualifying gas plants, on a similar timeframe as 111(d).

The scale and scope of the environmental upgrades required to keep older coal-fired generation units in operation has never been greater. Figure 1 illustrates recent and future regulatory activity.

FIGURE 1:
TIMELINE OF REGULATIONS AFFECTING COAL GENERATION



As noted, the regional haze rule presents an ongoing compliance obligation to coal plants. States must submit plans -- including goals -- covering the initial 2008-2017 period and reassess and revise those goals every 10 years thereafter. Many of the other rules are too new to quantify their effects. The path from a final rule to an incurred cost can be complex and uncertain.

Compliance costs associated with all of the above-described regulations may be important factors for Northwest coal plants. However, due to time limits and the lack of publicly available information on many of the specific compliance costs, this paper cannot address all the technologies used to upgrade coal plants to meet environmental regulations (more detail can be found in the Council's document, however).

This analysis focuses on costs associated with the regional haze rule, because these costs represent the bulk of environmental compliance-related costs facing the region's coal units. One technology, selective catalytic reduction (SCR), currently drives the majority of costs. To reduce NO_X emissions to meet the regional haze rules, the EPA often prescribes SCR or selective non-catalytic reduction (SNCR) technology. SCR reduces NO_X emissions through a chemical reaction: after combustion, the gas waste stream reacts with a nitrogen-based reagent such as ammonia, and then the reagent, in the presence of a catalyst (porous metals or ceramics), is removed from the waste stream.

Retrofits to add SCR can require significant plant modifications. SCR also increases ongoing operational costs, as the expensive catalyst must be replaced regularly.[4] SCR technology is the most expensive upgrade for a coal plant, and utilities sometimes chose early retirement or conversion to natural gas to avoid the expense.

> The next two sections respectively compare Council and NW Energy Coalition environmental cost assumptions and estimates for in-region and out-of-region coal plants.

IV. Environmental cost estimates for existing in-region generating resources

The Council's technical support document provides estimates on environmental costs for existing Pacific Northwest generating resources, a thorough description of current and future regulatory obligations, tables with estimated capital and operating costs, and a discussion of the complex issues surrounding these costs. The Council's analysis addresses such environmental regulations as NAAQS, regional haze, MATS, CCRs, cooling water, effluent limitation and the Clean Power Plan. It limits the analysis to plants explicitly modeled by the Council (the geographic constraint identified as a concern in Section II). The report also provides levelized revenue requirement estimates over 10-, 15-, and 20-year lifespans. It

[4] EPA, Air Pollution Control Technology Fact Sheet, at: http://www.epa.gov/ttncatc1/dir1/fscr.pdf

makes no assumptions about retirements nor does it specify how the emissions-retrofit capital cost information will be incorporated into the RPM or the power plan.

We present a tabular comparison of Council (from its technical support document) and Coalition analyses of probable environmental upgrades and costs associated with regional haze requirements. Then we highlight and discuss notable differences in the analyses.

TABLE 1:
COMPARISON OF ANALYSES ON ENVIRONMENTAL OBLIGATIONS ASSOCIATED WITH REGIONAL HAZE FOR PACIFIC NORTHWEST PLANTS

Unit and operating capacity in megawatts	Council's analysis[5]	Coalition's analysis
Boardman **606 MW**	In compliance; termination in 2020	Boardman will cease operations by Dec. 31, 2020, and thus will likely incur no significant future compliance/upgrade costs.
Centralia 1 & 2 **1,376 MW**	In compliance; no additional costs	Legislation requires Centralia unit 1 to cease coal operations by year-end 2020 and unit 2 by year-end 2025. Therefore, no significant future compliance/upgrade costs are likely.
Colstrip 1 & 2 **614 MW**	SNCR and separated over-fired air, dry sorbent injection, and additional scrubber vessel by 2017. Uncommitted expense, capital costs estimated at $140/kW, sourced from the EPA SIP/FIP (PPL Montana submitted the cost estimates used in the rule).	Current regional haze FIP imposed stricter limits for units 1 & 2. PPL Montana and the Sierra Club are appealing EPA's FIP with 9th Circuit Court.[6] Puget Sound Energy has modeled four different cost scenarios for Colstrip for its 2013 IRP, with two showing SCR installed on Colstrip 1 & 2.[7] One scenario assumes SCR in 2027 and the other assumes 2022.PSE quantified the total cost to all participants of SCR at $156 million for units 1 & 2[8] or about $254/kW.

[5] Council's analysis summarized from Table 2 in *Regulatory Compliance Issues Affecting Existing Northwest Generating Plants,* April 24, 2015, at: http://www.nwcouncil.org/media/7149177/draft7p_regulatorycomplianceandcosts_042415.pdf

[6] See disclosures in Puget Sound Energy's 2014 10-K and PPL Montana's 2014 10-K.

[7] Puget Sound Energy 2013 IRP, Appendix J Colstrip, at: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

[8] Totals found by dividing Puget Sound Energy's costs by its percentage ownership. Puget Sound Energy 2013 IRP, Appendix J Colstrip, at: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

Colstrip 3 & 4 **1,480 MW**	Currently in compliance; reasonable progress reviews may require SCR retrofit by 2027. Owners are uncommitted to the upgrade; capital costs estimated at $514/kW. Cost source is the Puget Sound Energy 2013 IRP.	Current regional haze FIP does not affect units 3 & 4. PSE has modeled four different cost scenarios for Colstrip for its 2013 IRP; two (2022 & 2027) show SCR and one shows SNCR installed on 3 & 4.[9] PacifiCorp (a minor owner) is assuming SCR for units 3 & 4 by 2023/2022 in all its IRP cases, anticipating future regional haze requirements.[10] PSE quantified the total cost to all participants of SCR at $760 million (about $514/kW) for units 3 &4.[11]
Jim Bridger 1 & 2 **1,060 MW**	SCR (unit 1, 2022; unit 2, 2021); owners are currently uncommitted to upgrade. Capital investment expected to be $257/kW according to 2007 CH2M-Hill BART analysis study (normalized to 2012 dollars).	SCR is required on units 1 & 2 by 2022/2021 respectively. The SIP still faces legal action.[12] The Wyoming PSC estimates the upgrade cost for all four units at more than $800 million, or about $377/kW.[13] In its preferred portfolio from the IRP process, PacifiCorp is assuming SCR will be installed according to the SIP schedule.[14]
Jim Bridger 3 & 4 **1,060 MW**	SCR (unit 3, 2015; unit 4 2016); owners are committed. Capital investment is $326/kW for unit 3 and $380/kW for unit 4.	Wyoming regional haze SIP requires SCR on all four units. Work is underway at a cost of $339 million[15] or about $320/kW, not including AFUDC (allowance for funds used during construction). These costs are consistent with the Council estimates, which include AFUDC costs.
North Valmy **1 & 2** **522 MW**	Currently in compliance, but reasonable progress review may require addition of SCR and wet flue-gas desulfurization (FGD) in the long term (2025–2030). Owners are uncommitted. Capital costs estimated at $257/kW for the SCR and $603/kW for the FGD. Source for the capital costs is Energy Information Administration average retrofit costs. Outside of Table 3, the Council acknowledges potential retirement of North Valmy as an alternative to these investments.	North Valmy is not covered under Nevada's regional haze SIP.[16] This was unsuccessfully challenged by an environmental group, but may be challenged successfully in a future SIP.[17] In its 2015 IRP process, Idaho Power included a number of scenarios for future environmental upgrades at North Valmy, including installation of SCR or conversion to natural gas.[18] Sierra Pacific Power, a 50% owner and the operator, announced intended retirement dates of 2021/2025 for units 1/2 for North Valmy.[19] However, Idaho Power, the other 50% owner, has not agreed to this schedule.

9 Puget Sound Energy 2013 IRP, Appendix J Colstrip, at: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

10 PacifiCorp 2015 IRP, Volume 1, Page 148, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

11 Totals found by dividing Puget Sound Energy's costs by its percentage ownership. Puget Sound Energy 2013 IRP, Appendix J Colstrip, at: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

12 See disclosures in Idaho Power 2014 10-K and PacifiCorp 2014 10-K.

13 Wyoming Public Service Commission Letter to the EPA dated December 16, 2013, at: http://psc.state.wy.us/pscdocs/dwnload/ChairmansLetter-JanetMcCabe.pdf

14 PacifiCorp 2015 IRP, Volume I, Page 148, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

15 Idaho Power 2014 10-K. Idaho Power disclosed its share of the cost was $113 million for Units 3 and 4, and Idaho Power has a 1/3rd interest.

16 Nevada SIP, at: https://ndep.nv.gov/baqp/planmodeling/rhaze.html

17 See disclosure in Sierra Pacific Power's 2014 10-K, and U.S. Court of Appeals for the Ninth Circuit opinion at: http://cdn.ca9.uscourts.gov/datastore/opinions/2014/07/17/12-71523.pdf

18 Idaho Power 2015 IRP process, at: https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/presentation110214.pdf

19 April 2013 Press release, at http://www.reuters.com/article/2013/04/04/utilities-nvenergy-coal-idUSL2N0CR1LO20130404

Both the Council and Coalition analyses review two other coal-fired plants included in prior power plan models, Corette and Hardin. PPL Montana announced in February 2015 it would retire Corette in August 2015.[20] Hardin Generating Station, a relatively new (2006) coal plant, has SCR and other environmental controls in place. The Coalition also found that Colstrip is facing a citizens' lawsuit under the Clean Air Act for alleged New Source Review violations. The 10-Ks of Puget Sound Energy, Portland General Electric, PacifiCorp, PPL Montana and Avista do not quantify potential costs resulting from the legal action.

> The Council and Coalition analyses have critical differences. Here are the major Coalition concerns.

A. The costs for Jim Bridger unit 1 and 2 SCR upgrades appear too low.

The Council used a 2007 CH2M-Hill study to estimate SCR costs for Jim Bridger 1 and 2 ($257/kW). Jim Bridger consists of four identical 530-MW units, for a total nameplate capacity of 2,120 MW. An alternate source, Wyoming's Public Service Commission, estimated the cost to upgrade all four units to SCR at $800 million, or about $377/kW. The Council's estimate for SCR at Jim Bridger 1 and 2 may significantly underestimate the cost for SCR upgrades. If an average of the units 3 and 4 cost is used ($353/kW), rather than the 2007 CHM2-Hill study escalated to 2012 dollars ($257/kW), the cost would be 37% higher, or about $100 million more.

B. Assuming Colstrip 1 and 2 won't need SCR is risky and understates potential compliance costs.

The Council's assumption that Colstrip 1 and 2 will upgrade using SNCR during the initial review compliance phase and then not need SCR as part of future progress reviews is problematic. PSE, which owns 50% of units 1 and 2, acknowledged during its 2013 IRP process that reasonable progress under the regional haze rule might mean SCR on all four units by 2027. PSE, at the Sierra Club's request, also ran an IRP scenario in which SCR was required on all units in 2021.[21]

While the Council has acknowledged that SCR on Colstrip units 3 and 4 might be required as part of reasonable progress reviews, it does not appear to have accounted for this possibility on units 1 and 2. By assuming that SNCR and the other upgrades will be required in this initial review only, with no accounting for potential additional controls under the reasonable progress requirement, the Council is underestimating the potential costs for environmental compliance at Colstrip 1 and 2. One of the utility participants has estimated the cost for SCR upgrades at units 1 and 2 at $156 million.[22]

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[20] http://pplweb.mediaroom.com/index.php?s=12270&item=137124

[21] Puget Sound Energy 2013 IRP, Appendix J Colstrip, at: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

[22] Appendix J, Colstrip, 2013 PSE IRP Process:http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppJ.pdf

C. The range of SCR capital costs shows the danger of using generic rather than site-specific estimates.

The Council's technical report uses a wide range for SCR capital costs. The lowest costs, which are "generically" sourced, may be too low. The lowest, $257/kW applied to North Valmy, are generic retrofit numbers from the *Annual Energy Outlook* produced by the Energy Information Administration (EIA). This number also is applied to Jim Bridger 1 and 2, and sourced (as noted in the table) from a CH2M-Hill study. The Council's numbers for Jim Bridger 3 and 4, however, are much higher, at $326/kW and $380/kW, respectively. The Council sourced these numbers from Idaho Power testimony regarding the SCR investment.

The highest number, sourced from Puget Sound Energy's IRP, was $514/kW for Colstrip 3 and 4. Colstrip's cost is thus exactly double the generic EIA retrofit cost. The wide range of numbers highlights the complexity of determining the costs of this expensive upgrade, and the potential problems of using generic numbers, which may understate the cost of maintaining coal operations under these regulations. Every retrofit is site specific, and may require significant modifications to the existing plant. As further evidence of the issues surrounding these costs, we note the situation in Wyoming: EPA, in a letter discussing the SCR cost calculations in the Wyoming SIP, asserts that real-world costs for retrofitting SCR have been between $79/kW and $316/kW in 2010 dollars, citing the average of "five recent industrial studies." Wyoming, however, said the appropriate estimate for Wyoming power plants is $415/kW - $531/kW.[23]

D. The Council does not provide levelized cost estimates without the upgrades to allow for comparisons.

Lacking a levelized cost comparison of plant costs with and without upgrades, it's impossible to see the upgrades' effects on the economics of delivered coal power. Since facilitating that comparison was a Council goal, we see this as a significant shortcoming of the report.

V. Environmental cost estimates for existing "out-of-region" resources

As noted, several PacifiCorp plants not modeled by the Council serve Northwest customers and are paid for in part by customers in Idaho and Oregon. Environmental upgrades and the associated cost estimates for plants *not* modeled by the Council are summarized in Table 1.

[23] EPA, http://www2.epa.gov/sites/production/files/documents/wy_rh_reproposalsigned23may2013.pdf

TABLE 1:
ENVIRONMENTAL OBLIGATIONS ASSOCIATED WITH REGIONAL HAZE FOR PLANTS OUTSIDE OF PACIFIC NORTHWEST

Unit and operating capacity in megawatts	Controls or actions; compliance date	Capital investment
Carbon 172 MW	This plant was retired in April 2015.	—
Cholla unit 4 380 MW	Unit 4, the only unit owned by PacifiCorp, is proposed for shutdown as a coal-firing unit by April 2025, as the least-cost way to comply with the regional haze FIP.[24]	—
Craig units 1 & 2 1,304 MW; PacifiCorp owns 165 MW	Upgrades to comply with Colorado's regional haze SIP are underway for unit 2 (SCR), with completion scheduled for 2018. Unit 1's status awaits a final rule: The original SIP required SNCR, but a subsequent settlement, which PacifiCorp opposed, requires SCR by 2021.[25] PacifiCorp is assuming SCR by 2021 in all its IRP portfolios. PacifiCorp's 2015 IRP assumes end of life as 2034.[26]	Original estimate of $213.1 million for SNCR on unit 1 and SCR on unit 2 has not been updated to reflect SCR on both units.[27]
Dave Johnston units 1 – 4 762 MW	Units 1 & 2 will be shut down by 2027 (or earlier). Unit 4 will be shut down in 2027 or 2032. The EPA's FIP (being appealed by Wyoming) would require SCR on unit 3 within a few years or a commitment to shut it down by 2027. PacifiCorp has indicated that if the appeal is upheld, it will choose to shut down unit 3 rather than invest in SCR.[28]	

[24] PacifiCorp 2015 IRP, Volume 1, Page 12, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[25] PacifiCorp 2014 10-K

[26] PacifiCorp 2015 IRP, Volume 1, Page 31, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[27] Salt River Project 2014 Annual Report, at: http://www.srpnet.com/about/financial/pdfx/AuditedFinancials_2014.pdf

[28] PacifiCorp 2015 IRP, Volume 1, Pages 12 and 148, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

Hayden 446 MW; PacifiCorp owns 78 MW	Upgrades to comply with Colorado's regional haze SIP (including SCR) will be complete in 2016 at a total cost of about $160 million.[29] PacifiCorp's 2015 IRP preferred portfolio indicates retirement of Hayden in 2030.[30]	$160 million
Hunter 1,361 MW; PacifiCorp owns 1,137 W	Utah's regional haze SIP required SO_2, NO_X and PM controls on Hunter units 1 & 2. Amended SIP (showing same) will be submitted early 2015 to EPA. Work was completed. Likely in anticipation of future regional haze SIP requirements, PacifiCorp's preferred portfolio shows Hunter 1 & 3 having SCR by 2021/2024, and Hunter 2 shut down in 2032 rather than installing SCR.[31]	Volume III of the IRP provides no cost information on these choices. PacifiCorp's 10-K has no disclosures on potential costs associated with these upgrades.
Huntington 909 MW	Utah's regional haze SIP requires SO_2, NO_X and PM controls on Huntington units 1 & 2. Amended SIP (showing same) will be submitted early 2015 to EPA. PacifiCorp's preferred portfolio case for Huntington in its IRP is SCR on unit 1 by 2022 and unit 2 shut down in December 2029, again, probably anticipating future SIP requirements.[32]	Volume III of the IRP provides no cost information on these choices. PacifiCorp's 10-K has no disclosures on potential costs associated with these upgrades.
Naughton 687 MW	Under the accepted portions of Wyoming's SIP, Naughton units 1 & 2 were upgraded with low-NO_X burners. Unit 3 would have been required to add SCR but PacifiCorp chose instead to convert it to run on natural gas by 2018. Technically, final EPA approval of the unit 3 choice is still pending.[33]	The costs for converting Naughton have been redacted in the relevant volume of the IRP. The conversion is underway.
Wyodak 340 MW; PacifiCorp owns 272 MW	EPA's FIP requires SCR; the FIP is under appeal and a decision is expected in 2016. PacifiCorp is noncommittal in its IRP, other than indicating it will continue to pursue appeal.[34] Upgrades are possible, or early retirement.	Details on the costs have been redacted in Volume III of the IRP. The EPA estimated the cost at $120 million, or approximately $352/kW, according to news articles summarizing the FIP.[35]

[29] Public Service Company of Colorado 2014 10-K and Salt River Project's 2014 Annual Report.

[30] PacifiCorp 2015 IRP, Volume 1, Pages 63 and 196, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[31] PacifiCorp 2015 IRP, Volume 1, Pages 63, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[32] PacifiCorp 2015 IRP, Volume 1, Page 63, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[33] PacifiCorp 2015 IRP, Volume 1, Pages 148 and 196, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

[34] PacifiCorp 2015 IRP, Volume 1, Page 12, at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

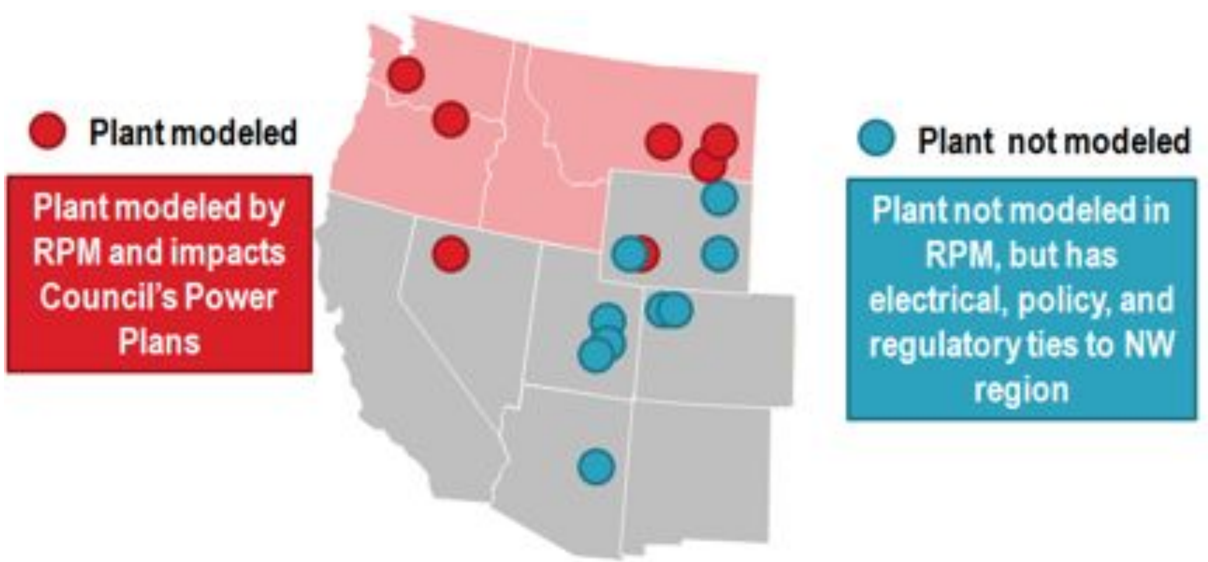
[35] See, for example: Casper Star-Tribune, "Rocky Mountain Power: Pollution Control Costs May Force Dave Johnston unit closure," February 1, 2014, at: http://trib.com/business/energy/rocky-mountain-power-pollution-control-costs-may-force-dave-johnston/article_62fccc34-75c2-5ad3-bd56-ee8933c4b483.html

VI. Location of existing resources

The Council's RPM tool considers a specific set of existing generating resources, including all plants in Oregon, Washington and Idaho and a small number of generators in Wyoming, Montana and Nevada. Certain generators in Wyoming and Nevada are included on the basis that their generation physically serves Northwest load.

Exclusion of the plants described in the previous section seems incongruous given these generators' electrical connections to the Northwest and their use by regional utilities to serve Northwest loads. From an operational perspective, a regulatory perspective and a policy perspective, it is logical for the Council to include or at least consider these out-of-region plants while developing its power plan. RPM resource modeling is conceptually summarized in Figure *2*.

FIGURE 2:
RPM COAL PLANT MODELING



Including these remote resources is critical considering that many of them are coal-fired generators that are subject to costly emission controls (as discussed in this paper). When planning exercises do not properly consider these cost parameters modeling results can be skewed toward preferring out-of-region generation that does not fully incorporate environmental costs. The RPM model determines regional import and export limits exogenously, allowing the Council to make assumptions about the degree and magnitude of electricity imports from out-of-region resources. These assumptions typically include “contracted” generation resources owned by PacifiCorp in such states as Montana and Wyoming.

PacifiCorp-owned generation is of particular interest to this investigation. Much of PacifiCorp’s coal fleet is not explicitly modeled in the RPM even though electrons from those generators support Northwest operation, and though Northwest billpayers are assigned a portion of these units’ generation and transmissions costs through the PacifiCorp multi-state process. By not properly assigning costs (and the associated environmental risk) to these electric imports from the rest of PacifiCorp’s system, the RPM may select a “sub-optimal” resource portfolio for the 7th Plan.

The Council explicitly models the coal plants in Table 2 as generating resources in the RPM.[36] Based on the information available on the Council’s website, these resources will be used in the development of the 7th Plan and are the extent of the in-region coal plants. The Council’s paper on environmental regulations addresses this set of resources.

TABLE 2:
COAL RESOURCES MODELED BY THE COUNCIL

Power plant name	Operator	Net summer capacity for planning purposes (MW)	State	Year first unit in service
Jim Bridger	PacifiCorp	2,120	WY	1974
Colstrip	PPL Montana	2,094	MT	1975
Centralia	TransAlta	1,376	WA	1972
Boardman	Portland General Electric Co.	606	OR	1980
North Valmy	Sierra Pacific Power Co.	522	NV	1981
Corette (J.E. Corette)	PPL Montana	153	MT	1968
Hardin Generating Station	Rocky Mountain Power[37]	119	MT	2006
Amalgamated Sugar: Nampa	Amalgamated Sugar	0	ID	1948
Amalgamated Sugar: Twin Falls	Amalgamated Sugar	0	ID	1948

The Council’s modeling does not include several coal resources that are used to supply Pacific Power customers in Oregon, and Rocky Mountain Power customers in Idaho. Pacific Power and Rocky Mountain Power are wholly owned subsidiaries of PacifiCorp. These plants are listed in table 3.

[36] Source: Spreadsheet from the Council entitled Projects.xlsm, download from link titled Existing and new/proposed power plants (Dec 2014) at http://www.nwcouncil.org/energy/powersupply/

[37] Rocky Mountain Power, the operator of Hardin, is an exempt wholesale generator (EWG) under the Public Utility Holding Company Act (PUHCA), and is a wholly owned subsidiary of Bicent Power. It has no relationship with the utility subsidiary of PacifiCorp of the same name.

TABLE 3:
PACIFICORP-OWNED COAL-FIRED GENERATING RESOURCES NOT IN COUNCIL MODELING

Power plant name	Operator	Capacity (MW)	State	Year first unit in service
Carbon	PacifiCorp	172	UT	1954
Cholla	Arizona Public Service Co.	380	AZ	1962
Craig	Tri-State G & T Assn. Inc.	165	CO	1979
Dave Johnston	PacifiCorp	762	WY	1959
Hayden	Public Service Co. of Colo.	78	CO	1965
Hunter	PacifiCorp	1,137	UT	1978
Huntington	PacifiCorp	909	UT	1974
Naughton	PacifiCorp	687	WY	1963
Wyodak	PacifiCorp	272	WY	1978

Plants from both these lists have planned or committed environmental upgrades that will be costly. The upgrades for the out-of-region plants are discussed in this paper, and the upgrades for the in-region plants are discussed both here and in the Council's paper. Given the magnitude of these costs, it's critical that the Council consider including these generators in its modeling. Including these resources in power plan development is justified by the strong operational, regulatory and policy ties between the Table 4 plants and the Northwest region.

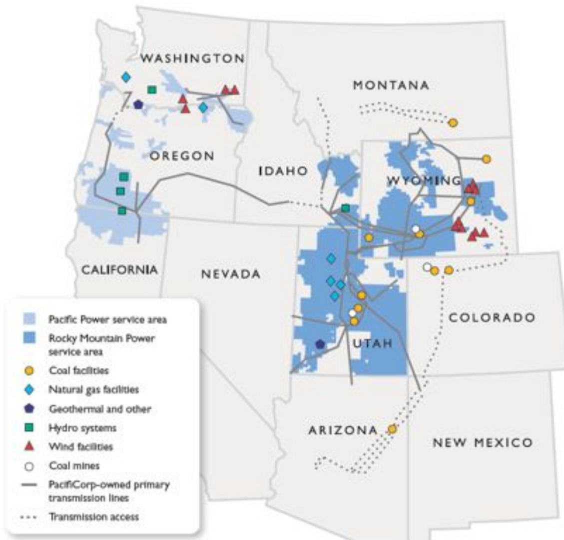
We explore these relationships on the following pages.

A. Operational ties

PacifiCorp controls two balancing authorities primarily covering portions of six states, including part of Northern California. The utility owns significant transmission capacity between its eastern balancing authority (PacifiCorp East or PACE) and its western balancing authority (PacifiCorp West or PACW). Through the electrical tie between the two systems, PACW resources are typically dispatched to meet loads in PACE.

Transmission ownership between the eastern and western PacifiCorp systems is another example of the ties between the coal-rich eastern system and Northwest billpayers. As Figure 3 shows, PacifiCorp has transmission access that links its eastern coal resources to loads and customers in Oregon, Washington and Idaho. This transmission capacity plays a key role in PacifiCorp's IRP process, and allows for PACE and PACW to provide capacity and energy support across the transmission ties to minimize system costs to PacifiCorp billpayers.

FIGURE 3:
PACIFICORP SERVICE AREA[38]



Movement toward the fully functional energy imbalance market (EIM) further illustrates the PACE/PACW operational connections. PacifiCorp joined the California Independent Service Operator (CAISO) to more economically balance real-time supply and demand across its combined footprint (as limited by transmission capacity and generation operations, among other constraints). Figure 4 shows the aggregated 15-minute EIM transfers between PacifiCorp and the CAISO for a few days in November 2014.

While Figure 4 merely shows significant transfers from PacifiCorp to the CAISO, Figure 5 completes the picture by showing significant EIM transfers from PACE to PACW over the same period. Comparing the two, it is evident that most of these PacifiCorp EIM transfers are from PACE generation, demonstrating PacifiCorp's ability to economically transfer PACE resources into the PACW system. Clearly, resources in the eastern half of the system are connected electrically to the Northwest region.

38 http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf

FIGURE 4:
EIM TRANSFERS BETWEEN PACIFICORP AND ISO[39]

FIGURE 5:
EIM TRANSFERS BETWEEN PACE AND PACW

[39] http://www.oatioasis.com/NEVP/NEVPdocs/ISO_Presentation_for_NVE_OATT_Meeting.pdf

B. Regulatory ties

Regulatory ties are prevalent as well. Many customers in the Northwest region pay for PacifiCorp's out-of-region generation resources and transmission assets From a cost and risk standpoint, excluding these generators from the Council's modeling will affect model results and the 7th Power Plan's optimal resource portfolio.

Idaho and Oregon participate in the PacifiCorp multi-state process (MSP).[40] The MSP is a regulatory agreement that governs allocation of PacifiCorp's costs among billpayers in the several states it serves. Thus, Oregon and Idaho PacifiCorp customers receive and pay for generation from coal resources outside of those modeled by Council. In fact, Oregon's fuel mix disclosure for Pacific Power currently shows 67.4% of the non-market purchased energy from Pacific Power was coal-fired.[41] Washington does not participate in the MSP, and state regulators restrict ratepayer-funded generation capacity to resources physically located in the Pacific Northwest region.[42] However, the MSP is currently up for renewal and it is remotely possible that a new agreement would include Washington state – increasing the number of Northwest billpayers sharing the costs of expensive environmental upgrades at existing coal generating units.

Recent MSP allocations are listed in Table 4 (based on the Wyoming rate case). Past MSP allocations have similarly allocated PacifiCorp costs. From regulatory and cost-recovery standpoints, Northwest billpayers have a significant stake in resource decisions made outside of the Council's planning footprint. The Council's power plans would more effectively minimize risks, costs and environmental damage if they fully considered generation with regulatory ties to the region.

TABLE 4:
RECENT MSP ALLOCATIONS

State	MSP state allocation (%)
California	1.57%
Idaho	5.58%
Oregon	26.02%
Utah	43.01%
Washington	7.86%
Wyoming	15.97%

40 As referenced in this Wyoming Public Service Commission letter to the EPA dated December 2013 http://psc.state.wy.us/pscdocs/dwnload/ChairmansLetter-JanetMcCabe.pdf and elsewhere.

41 http://www.oregon.gov/energy/pages/oregons_electric_power_mix.aspx

42 https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/WA_GRC_handout.pdf

C. Regional policy ties

The Council's document details EPA's proposed Clean Power Plan, Rule 111(d). It is too early to fully assess the rule's potential effect on coal units, but it will likely influence many of the pollution control equipment retrofit investment decisions discussed in this paper. If coal units must be shut down so states can comply with 111(d), investments in costly pollution-control retrofits make no economic sense.

Northwestern states and utilities may look to the Council to support them in developing and analyzing state 111(d) compliance plans. Given the operational and regulatory ties the Northwest has to coal units currently excluded from the Council analysis, the models will be incapable of fully assessing 111(d) compliance scenarios from a regional perspective. Because prudent planning requires a regional analysis of state compliance plans, the Council must begin to bring these out-of-region resources into the equation.

VII. Summary and policy recommendations

Based on the findings in this report, the Coalition offers the following recommendations for consideration by the Council and others involved in the 7th Power Plan development process:

Fully account for the environmental costs of "in-region" plants – The Council's recent review of environmental costs for coal plants (in the Northwest planning footprint) understates some of these costs. The Coalition's independent review suggests that potential or likely costs for environmental upgrades will be significantly higher for certain plants. Specifically, the Council should reconsider its cost estimates for Jim Bridger units 1 and 2, as well as Colstrip units 1 and 2.

Consider "out-of-region" plants and their environmental costs – The Council's current modeling ignores coal plants identified as outside of the Northwest region. Based on this, Council's Power plans do not consider their operational and forthcoming environmental capital costs. These coal plants have strong operational, regulatory and policy ties to the Northwest region, and their inclusion in the power plan development process is critical since they face hundreds of millions of dollars in costs to comply with environmental regulations, a portion of which will be paid for by Northwest customers.

Appropriately reflect EPA Clean Power Plan implications – The Council should be cautious in interpreting modeling results from its carbon emission reduction scenarios given the omission of environmental costs for in- and out-of-region plants. A narrow interpretation of state-to-state electrical interchange will limit the Council's usefulness in evaluating Clean Power Plan compliance scenarios given the interconnected nature of the Northwest and the cross-border cost allocation implications that could drive state compliance strategies.

Incorporating these recommendations into the 7th Power Plan will help to identify a truly cost-effective future resource portfolio, striking an appropriate balance between reliability, economics and the environment.