December 18, 2015

Mr. Phil Rockefeller, Chair
Northwest Power and Conservation Council
851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204

Dear Chairman Rockefeller,

On behalf of the PNUCC Board of Directors and members I want to thank the Council for the open, collaborative dialogue regarding the development of the draft 7th Power Plan. For the past two years, PNUCC members and staff have been fully engaged in your advisory committees and review of the analysis as it has unfolded. While we've offered our ideas and thoughts along the way, we appreciate this opportunity to provide these more formal comments as you move toward finalizing this seventh edition of the Power Plan.

PNUCC's goal for the final Plan is that it accurately presents the state of the Pacific Northwest power system and the challenges facing the industry. In other words, the Council's plan and the electric power industry are largely in agreement about the issues the region will be tackling. This is an unprecedented time of change for the power industry, nationally as well as in the Pacific Northwest. Having a final plan that describes the challenges, identifies the uncertainties that lay ahead, notes the difference between the region as a whole and individual utilities, and recognizes utilities' efforts to meet their customers' needs will be extremely valuable.

In addition to the general observations and suggestions that follow, Attachment A includes a variety of more technical thoughts for your consideration. We don't think you will find any surprises here. We aim to underscore points we have made previously and feel are important to the region's electric utilities.

PNUCC applauds several aspects of the draft Plan.

1. The analytic approach is solid.

The scenario approach utilized in developing this 7th Power Plan is providing us information to help compare the relative risks, costs, and benefits of pursuing different paths for resource development in the future. With the range of the scenarios and sensitivities that have been examined for the draft Plan, the Council has shed light on several less-understood realities.

The scenario analysis highlights the challenges of using intermittent renewable resources to meet the Northwest's goals to reduce carbon production. It shows that, in and of itself, acquiring additional amounts of intermittent renewable resources such as wind and solar power is an expensive way to reduce emissions. The draft Plan findings on this issue are driven by solid analytic models that illustrate the principle problem facing the region is a shortage of winter peak capacity. And you show that new renewable resources do not add substantial amounts of winter peaking capability, and when built, require additional resources to back them up when the wind is not blowing or the sun is not shining.

We also agree with the finding that the **region's power system needs additional capacity resources to meet winter peak demand**. This is in alignment with what has been reported in the last several *PNUCC Northwest Regional Forecasts*. This is an important point in a time when energy resources with little peaking capability are being added to the system to meet state and federal mandates.

2. Useful communications vehicle.

The 7th Plan presents a significant opportunity to communicate to policymakers, consumers, interest groups, and the media about the state of the Northwest electric power industry.

PNUCC is pleased to see that the draft Plan plainly spells out the unique circumstances of individual utilities and that analysis looking at the region as a single utility does have its limits in understanding individual utility situations.

The Council is viewed as expert on the region's power system. And your draft 7th Plan highlights challenges and the effort to ensure a reliable and affordable power supply for the region. It provides the context for explaining key regional issues and policies. And because of this reputation we have concern about the different messages regarding the adequacy of the power system from your most recent Resource Adequacy study and the results of the analysis for this Power Plan.

PNUCC recommends that the final Plan acknowledge the results of the Resource Adequacy work and how they differ from 7th Plan findings. We see that the most current Resource Adequacy study showed the region in good shape until coal plants are retired at the end of 2020 when additional power supply is needed. This study, from only a few months ago, appears to contradict the findings of the draft Plan, where in the first five years, up to 700 MW (on average) of demand response are built, energy efficiency is acquired, and there is no need for new generating resources once the coal plants are retired at the end of 2020. While both reports find the region capacity-constrained, the timing of the constraint moves five years earlier in the draft Plan.

3. Energy efficiency is a high priority.

The draft Plan acknowledges the region's success in acquiring conservation in the last five years and sets high expectations for acquiring savings into the future. Utilities are planning on significant amounts of conservation in their integrated resource plans as well. PNUCC sees the challenge will be in syncing up our accounting methods to ensure we are comparing apples to apples. Action Plan items to help address this challenge will be helpful. In regard to specific recommendations on energy efficiency, we have a couple of key points.

PNUCC recommends that the final Plan includes a review of the 2 to 1 winter peak to energy savings ratio estimate. This winter peak to energy savings ratio looks optimistic in comparison to what utilities are reporting in their own integrated resource plans. And to what degree and magnitude a utility can plan on that peak reduction needs further investigation and refinement. See Attachment A for more data on what utilities are assuming in their own plans.

PNUCC recommends the resource strategy for the final Plan include a range for energy efficiency of 1,300 to 1,450 MWa by 2021 as described on page 1-9 of your draft Executive Summary. There are a host of reasons leading to this conclusion, including: accounting for uncertainty of future load growth; uncertainty about gas price projections; other factors affecting the region's ability to acquire conservation; and the range of conservation developed in the many scenarios analyzed in the draft plan.

4. Demand response is promising; needs further vetting.

The potential for demand response programs to reduce peak hour loads is attractive due to the potential for low cost and ability to meet rare peak load events. Utilities have secured opportunities where they could, with customers that have interest in taking payment for the potential risk of having their electricity supply interrupted. They are on the lookout for further opportunities and examining the cost of implementing these programs.

Thus far, utilities are finding some opportunities but are also discovering challenges in implementing these types of programs. Based on utilities' experiences, we are concerned the Plan's costs and availability assumptions for demand response are overly optimistic. (See Attachment A for more detail.) **PNUCC recommends the Council consider demand response as a promising potential opportunity with further investigation of costs and availability through a stakeholder process similar to what has been done for other resources.**

5. Carbon emissions analysis sets the stage.

The Council's findings regarding Pacific Northwest carbon emissions from electric power generation have been quite informative. Your work has highlighted pathways for reducing carbon emissions in the Northwest. However, as discussed in Attachment A, your estimates of the current system's carbon emissions may be a little low. We recommend that there be some additional review of that estimate to ensure the Plan's credibility.

With that said, **PNUCC is pleased that the 7th Plan acknowledges the Pacific Northwest's low carbon footprint and the value of the hydropower system**. We agree that with accounting for retirement of the Boardman, Valmy 1 and Centralia 1 coal plants, the region as a whole is well on the way to meeting the EPA's Clean Power Plan carbon emission reduction goals. And we also know that on a state-by-state basis, there will be challenges to meeting these goals.

6. Power need and resource portfolio basics helpful.

One of the benefits of the work to develop the draft 7th Plan is the information that is gathered on potential new power supply. In this case, the Council has identified, beyond energy efficiency, that market purchases, demand response and natural gas-fired generation as the best options. PNUCC agrees that these are the most realistic choices utilities have today. And it is helpful that the analysis indicates that these resource choices have similar costs. Of course, the circumstance for any single utility will dictate the choice or combination of choices that will be a least cost strategy to maintain system reliability.

PNUCC is concerned that the draft Plan may be setting an unrealistically low expectation for the need for natural gas-fired generation in the next six years. We agree that the final Plan should be focused on the carbon free resources to the extent possible. However, readers should understand the need to maintain a reliable power system. This could require some utilities to build new natural gas generation depending on future conditions.

We especially appreciate your hard work and personal engagement in the development and refinement of this draft Plan. And we look forward to continuing to work with you and your dedicated staff on the highest priority Action Plan items as soon as the Plan is finalized. If you have any questions please contact Shauna McReynolds, PNUCC Executive Director.

Sincerely,

John Prescott, Chairman
PNUCC Board of Directors

cc: Council Members, Steve Crow, Tom Eckman, Mark Walker, PNUCC Board of Director

Bringing the *Power* of good ideas *Together.*

Attachment A

PNUCC Technical Comments on draft 7th Plan

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PNUCC Technical Comments – Draft 7th Power Plan

The draft 7th Power Plan, released mid-October by the Northwest Power & Conservation Council, presents insights into the future of the Northwest electric power industry. The draft Plan looks reasonable overall, yet at a granular level PNUCC has some areas of concern.

The goal for PNUCC is to ensure the 7th Power Plan provides an accurate picture of the state of the Northwest power system and the anticipated challenges and issues that will be at the forefront for the electric power industry, while noting the difference between the region as a whole and individual utilities.

The following comments are provided to both encourage changes prior to the Plan being finalized as well as identify areas for future discussion and analysis.

"One utility" approach has limitations

The analytics leading up to the 7th Power Plan, as with all the Council's Plans, models the Northwest electric power system as if it is owned and operated by one large utility. This approach masks the unique circumstances of each of the region's utilities and dispatches the system in a way that cannot be achieved with the region's current mixture of utilities, technical constraints, institutional barriers and legal constraints. Although the draft Plan recognizes the limitation of this framework, the issue persists and shapes much of the plan's analytics. The "one utility" approach is critical to the plan's findings and is likely at the core of several of PNUCC's concerns.

One issue is that in the draft Plan thermal resources appear to be under dispatched, creating unrealistic low carbon dioxide emission forecasts. PNUCC suspects this is in part due to the model optimizing hydroelectric production to serve the region, rather than the normal practice of some hydro being sold out-of-region instead of displacing in-region resources.

While there is little for the Council to do to change this, it is important that the final Plan observe the potential implications of actual resource dispatch in the region being different than what is estimated by the Council's models.[1] It would be beneficial to cross-check the 7th Plan analytics and see if there are any areas aside from dispatch/emissions where the "one utility" approach materially affects the findings and regional recommendations.

Resource need looks early and differs from other Council studies

The draft 7th Plan identifies winter peak capacity as a key area of concern for the Northwest. This is a finding supported by the PNUCC *Northwest Regional Forecast*. Both documents also find the region energy surplus over the next six years. Neither the draft Plan nor the *Northwest Regional Forecast* closely examines flexibility needs. PNUCC is pleased to see the draft Plan discussing flexibility needs

[1] This issue is explored in more detail on page 9 and 10 of these comments

qualitatively as this continues to be a major factor shaping utilities' future resource plans and what they ultimately acquire.

PNUCC is concerned about the timing of the need for new resources in the draft Plan. The draft Plan indicates a need for additional capacity in 2016 with immediate acquisition of demand response. While the PNUCC *Northwest Regional Forecast* shows a deficit in 2016, the deficit is relatively small compared to the ability to import power into the region.[2] Looking forward, aside from energy efficiency and low levels of demand response, few utility scale resources are expected to come online in the next three years according to utility plans submitted to PNUCC. In comparison, the draft Plan sees a need for an average of around 700 MW of demand response by the end of 2018.

Perhaps most importantly, the draft 7th Plan adequacy findings differ from other Council studies, most notably the 2014 and 2015 Resource Adequacy Assessments. The 2015 Regional Adequacy Advisory Committee assessment found the region to be adequate under business as usual (including 6th Power Plan energy efficiency) until 2021. In 2021, after Boardman and Centralia Unit 1 go offline, it showed the region needed around 1,150 nameplate megawatts of dispatchable generation to again achieve adequacy. This is different than the 7th Draft Plan which sees the need to develop capacity resources *before* 2021, and is largely adequate in 2021. As such, within five months, the Council has released two reports, one recommending that the region needs to consider developing new capacity resources immediately, the other finding the region largely adequate until 2021. With such significant changes in key findings, the Council should document what has changed and explain why the new finding is supported by better data and analysis.

The region relies on the Council's work in a variety of forums. A fundamental change in adequacy findings without any significant changes to the system raises concerns regarding consistency and accuracy. PNUCC recommends that the Council better implement checks to insure that large swings in regional load forecasts and the need for new power resources are understood by all parties and are judged to be the most accurate forecasts available before major changes are made.

Council should better align internal load forecasts

The draft 7th Plan uses a load forecast that differs substantially from the 2015 RAAC study forecast. In the draft Plan current policy scenario the Council forecasts growth at a rate of negative 0.42% per year, whereas the 2015 RAAC study projects positive growth at 0.48% per year, nearly a full percentage point different. PNUCC suspects much of this difference can be explained by the use of an end use model for the 7th Plan and an econometric model in the RAAC forecast. Going forward, it would behoove the Council to better align the models and/or forecasts to ensure consistency between studies.

Table 1 below compares the draft 7th Plan forecast to the 2015 RAAC forecast. On average, the draft 7th Plan load forecast is roughly 1,000 MWa and 750 MW lower than the RAAC forecast in 2020. This difference raises load forecasting accuracy concerns. That said, PNUCC is pleased to see action item

[2] The *Forecast* does not include market purchases in its load/resource calculations

ANLYS-4 addressing the issue of different load forecasts between Council studies and would like to see this item prioritized.

	2020 avg. MWa	2020 avg. Q1 1hr peak
Current policy (1B)	20,732	32,517
RAAC 2015 study	21,745	33,259

Table 1 – Draft 7th Plan forecast low compared to other Council and PNUCC forecasts

Future resource options align with utilities' view

Overall, the draft 7th Plan identifies similar types of future resources as utility integrated resource plans for ensuring an economic and adequate power system: energy efficiency, natural gas-fired generation, market contracts, demand response and just enough renewables to comply with state laws.

The draft 7th Plan has several scenarios whose costs do not differ substantially from the existing policy scenario.[3] Among these is the sensitivity where demand response is assumed to not be available and the region builds natural gas units more often. One scenario with significantly lower costs is when the region relies more heavily on power imports for adequacy and acquires, on average, 100 MW of demand response total. In sum, the draft Plan's analysis shows that a mix of demand response, new natural gas plants and market purchases will lead to a least cost strategy. Due to different utility circumstances, utility plans also call for some mix of these three resources to create a least cost resource portfolio.

Adopt a range for energy efficiency goals, not a fixed target

Given all the possible futures analyzed, it is odd that the draft Plan chose a single point, 1,400 MWa, rather than a range for its six year energy efficiency goal. Without carbon pricing, and under the current policy scenario, the average ideal energy efficiency goal is around 1,300 MWa. Even with carbon pricing included, there are also scenarios in which the average energy efficiency build is around 1,300 MWa.[4] In some carbon pricing scenarios the goal shifts closer to 1,450 MWa. PNUCC recommends that the 7th Plan use the energy efficiency range illustrated below in Figure 1 of 1,300 to 1,450 MWa to better account for future uncertainty. The draft Plan acknowledges this range on page 1-9: "in all scenarios tested… the amount of cost-effective efficiency developed averaged between 1,300 and 1,450 average megawatts by 2021…"

[3] See page 3-40 and 3-41
[4] Scenario S2.1, low (current) gas prices with carbon risk

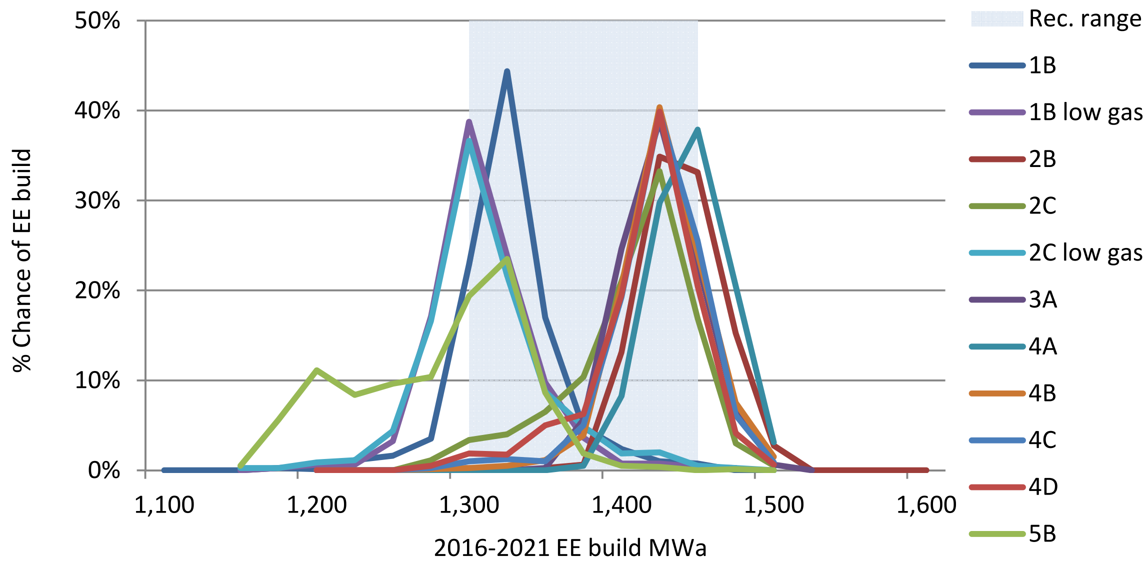

Figure 1 – An energy efficiency goal range would help account for uncertainty

Assumed energy-to-peak ratio for energy efficiency needs review

PNUCC is concerned that the 2 to1 peak to energy ratio assumed for energy efficiency by the 7th Plan is notably higher than the ratio assumed by many utilities. Further, when reconciling Council models it was found that RPM was understating the contribution of capacity resources relative to GENESYS and made a simplified adjustment increasing the capacity contribution of energy efficiency by 20% to 2.4 to 1 (the capacity contribution of combined cycle combustion turbines was also increased by 30%).

Looking at regional utility integrated resource plans, some utilities are finding a smaller peak to energy ratio. For example, in their 2015 Plan, Avista estimated this ratio to be 1.5-to-1. Puget Sound Energy has estimated a ratio of 1.6-to-1 for their draft 2015 Plan. Additionally, the energy efficiency measures regional utilities will acquire may differ from what the 7th Plan predicts, which could affect peak-to-energy ratio. In the "Six Going on Seven" review Bonneville found large differences between what measures were projected to be acquired, and what was actually acquired.[5] Lastly, much of the end-use data the Council used to create the energy efficiency peak contribution are from the 1980s. Consumers today likely use electricity differently.

While the Council's analytic approach makes sense, the underlying data may have limited applicability to a 20 year plan. PNUCC is pleased to see the Council recognize this issue in action item REG-1, and looks forward to working with the Council and others to better understand the peak shaving benefit of energy efficiency.

[5] http://www.bpa.gov/EE/Utility/toolkit/Documents/results_presentation_crac_032015_v2_final-read-only.pdf

Uncertainty with demand side measures not modeled

PNUCC finds it inconsistent for the Council to evaluate a wide range of uncertainties in the Plan yet energy efficiency is treated as deterministic supply curves, without any uncertainty. This occurs in light of Action Item REG-1 which clearly illustrates there is uncertainty and risk. All resources have uncertainty in both their cost and their actual operations. Energy efficiency is no different and in some ways even it has greater uncertainty because of the diverse nature of the programs and installers used to deliver the resource.

It is not practical to expect modeling changes to incorporate explicit analysis of the stochastic uncertainty of energy efficiency because it will require new model formulations. Thus, PNUCC recommends that analysis of uncertainty in energy efficiency savings be a high priority for the next Power Plan, and to discuss this limitation qualitatively in the final 7th Plan. This issue further supports the recommendation above that conservation measures be represented as a target range instead of a single point.

Demand response inputs look optimistic

PNUCC has surveyed our members and the draft Plan's input assumptions used for the cost and speed of acquisition of demand response appear unrealistic based on actual utility experience. The demand response inputs are entirely from a consultant's report created without regional stakeholder input. This process stands in stark comparison to the multitude of formal advisory committees used to create other resource inputs.

Many regional utilities have identified new demand response as a resource and have utilized it in their preferred resource portfolios. In their 2015 integrated resource plan, Avista estimates 37 MW of demand response achievable in their service territory by 2035, with costs in excess of $120/KW-year ($2012).[6] PacifiCorp estimates around 130 MW of demand response available by 2034, roughly half available only in the summer, with costs ranging from $70 to $152/KW-year.[7] Puget Sound Energy found 155 MW of potential by 2035 with prices starting at $105/KW-year.

In comparison, the Council estimates that by 2021 there are 3,720 MW of demand response available in the Northwest with 1,320 MW of it available at less than $25/KW-year. Given these assumptions, it is no surprise that the model on average acquires around 700 MW of demand response by the end of 2018.

The modeling of demand response in the 7th Plan glosses over the complexity of acquiring, deploying and dispatching the resource. When double checking adequacy using the GENESYS model, the total MWh of the resource available over the period of one year is limited. In practice, there will be limits on how many continuous hours a demand response can be actually used per event. Additionally, demand response is a capacity only resource, and although the region in aggregate is capacity deficit, some

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[6] Avista 2015 Integrated Resource Plan, appendix C, page 33.
[7] PacifiCorp 2015 Integrated Resource Plan, IRP studies volume 3, page 4-3.

utilities are capacity surplus. Although there could be demand response potential in a utility service territory, the utility may have little incentive to find and develop the resource due to a lack of need. This would lead to less total regional demand response development than forecasted by the draft Plan. PNUCC recommends that in future Plans the Council collaborate with the region's utilities to develop more realistic demand response assumptions based on actual regional experience with the resource.

Northwest utilities have already acquired hundreds of megawatts of demand response, and currently utilize the resource to help meet extreme peak load events. However, the demand response assumptions used in the draft Plan are very different than the actual experience of utilities that have acquired demand response in recent years. PNUCC is happy to see multiple action items recommending further study of the resource, but is concerned that the draft 7th Plan overstates the resource potential in the six year Action Plan.

Gas-fired resource acquisitions may be too low

The Council's assertion that under currently policies (1B) the region will build new natural gas-fired generation less than 5% of the time by 2026 does not seem likely given current plans to shut down three existing coal-fired power plants by 2026 (with two units offline at the end of 2020) and the draft Plans overly-optimistic demand response assumptions.[8] PNUCC has reviewed current utility integrated resource plans and believes there is a reasonable chance that additional gas-fired power plants may be developed.

One reason for the Council not seeing the need for new thermal resources is due to the Northwest being modeled as one utility. This assumption allows the hydro system to be optimized for all utilities, public and investor-owned. In reality, investor-owned utilities must compete with other buyers, such as California, for surplus federal system power. As a result, the Plan likely overstates the amount of energy and capacity available to serve Northwest utility loads. PNUCC recommends the final Plan recognize that the need for new energy and capacity resources, including new gas-fired power plants, may be underestimated because of the perspective built into the models.

Additionally, demand response is used in the Plan instead of natural gas as the lowest cost capacity resource option. When demand response is excluded from the analytics (scenario S3 and S3.1), the odds of a new gas build by 2021 increase substantially. While demand response will play a role in the future Northwest power system, as noted in the section above, the Council's demand response inputs appear to be overly optimistic. If utilities find that demand response is not available, cost effective, or if regional seams issues prevent the acquisition of the resource, a utility may need to develop a gas unit instead.

PNUCC recommends that the final Plan emphasize that utilities may need to build thermal resources in order to maintain system reliability. This could in part be done by adding back in the stand-alone action item "RES-7. Secure and Maintain Thermal Resource Options." This item appeared in prior drafts of the action plans, but was relegated to sub-bullet level in the draft 7th Plan.

[8] Boardman (end of 2020), Centralia (Unit 1 end of 2020, Unit 2 end of 2025) and Valmy (likely at end of 2025)

Plan over estimates thermal and avoided resource capacity costs

PNUCC is concerned that using an aeroderivative gas-fired combustion turbine, as the gas peaking proxy resource, is not necessarily the least cost for new thermal capacity. While the Regional Portfolio Model (RPM) builds new resources to meet energy and capacity needs, the model cannot properly value flexibility or other ancillary services provided by new gas-fired generation. By only providing the model an aeroderivative gas peaking unit, the draft Plan overstates the cost of building new gas peaking resources in the region. The Council should enhance its ability to study the value of flexibility and ancillary services in future work to better value new thermal capacity and/or allow the model to build other peaking resources.

This issue is not only specific to the assumptions used in the RPM. In appendix G of the Plan the Council uses an aeroderivative unit as a proxy for energy efficiency avoided capacity cost. Once again, this over values the cost of avoided capacity given that an aeroderivative provides flexibility, ancillary services, and energy whereas RPM only values energy and capacity.

If a utility needs a pure capacity solution and not one involving great amounts of energy, flexibility or ancillary services, they would more likely build a less expensive frame unit. While a frame still provides some ancillary services, more of its cost is typically borne for capacity than an aeroderivative. For future work, PNUCC recommends that the Council develop a method for valuing resource flexibility and ancillary service benefits.

Lastly, the draft 7th Plan currently gives the impression that the RPM can select among various gas peaking resources. This is due to Appendix H listing and describing various resources that were not available for RPM to select in the Council's scenarios. While it is beneficial from an educational perspective to describe these various resource types, the Plan should document which resources were excluded from the scenario modeling process and why.

Carbon dioxide reduction analysis helpful

The findings that carbon pricing will not result in a dramatically different resource portfolio than current policy, and that variable energy renewable sources are expensive carbon reduction strategies, largely comport with utility findings. [9] PNUCC observes that even in scenarios with carbon taxes in excess of $100 per ton, few, if any, new renewables are built for carbon abatement. The draft Plan notes this is partly due to wind and solar not adding much winter peak capacity to the power system.

The draft Plan also includes a sensitivity analysis with an assumed 35% renewable portfolio standard for the region. Figure 2 is a chart from an August 2015 Council meeting noting that the estimated cost of reducing carbon emissions via a 35% renewable standard is an expensive option costing nearly $400 per ton.[10] PNUCC finds this analysis in the draft Plan to be helpful in informing the public policy debate surrounding increasing renewable portfolio standards.

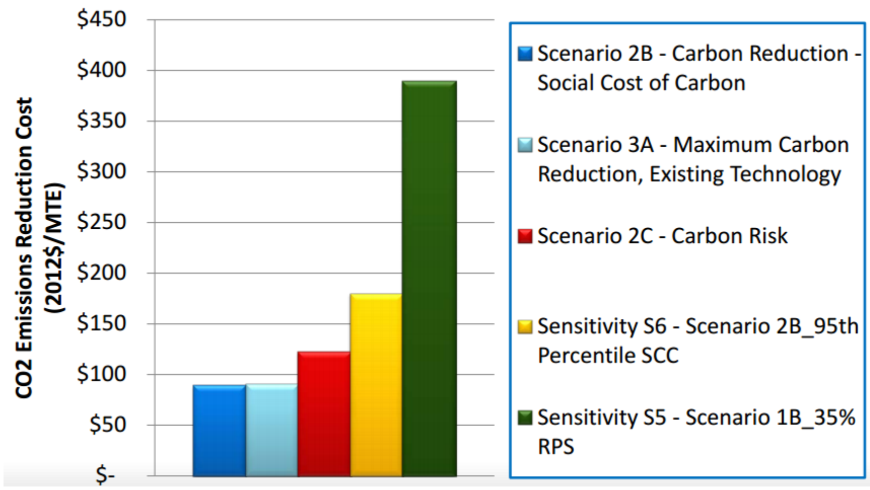

Figure 2 – Cost of reducing carbon under various approaches (Council figure)[11]

Carbon footprint estimates look optimistic

PNUCC is concerned that the draft Plan underestimates the Northwest's future carbon dioxide emissions. Over the past decade (2005-14), the Northwest total power system CO_2 emissions have ranged between 46 and 63 million metric tons per year, averaging 57 million metric tons per year.[11] The large range is mostly due to yearly hydro generation variations, which are in turn due to precipitation, snowpack, and other factors. Fuel prices and electric demand factor into annual CO_2 emissions as well.

On page three of the executive summary, the draft Plan shows CO_2 emissions declining in scenario 1B (current policy, no carbon pricing) "from about 55 million metric tons in 2015 to around 34 million metric tons in 2035…" The Plan notes that this decrease is largely due to the retirements of coal plants

[9] For example, in 2013 IRP's Avista, PGE and Puget all found carbon reduction with wind/solar to cost in excess of $150 per ton. E3 found that California going to a 40% RPS would abate carbon at a rate in excess of $350 per ton
[10] http://www.nwcouncil.org/media/7149414/saac-8-4-2015-scenarioupdate.pdf
[11] EIA data. See PNUCC's "Carbon Emissions – A Northwest Perspective" report for more details on carbon emissions from the Northwest power system

Boardman, Centralia and North Valmy, the achievement of the Plan's energy efficiency goals and the increased use of existing natural gas-fired generation. The draft Plan finds that "In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's carbon emissions limits, even under critical water conditions."

However, in the same current policy scenario, the Council sees emissions averaging 43 million metric tons per year from 2016-2020, before any coal units go offline, and before substantial amounts of new energy efficiency are acquired. Figure 3 shows a comparison of the forecasted current policy emissions to historical trends for the total power system.

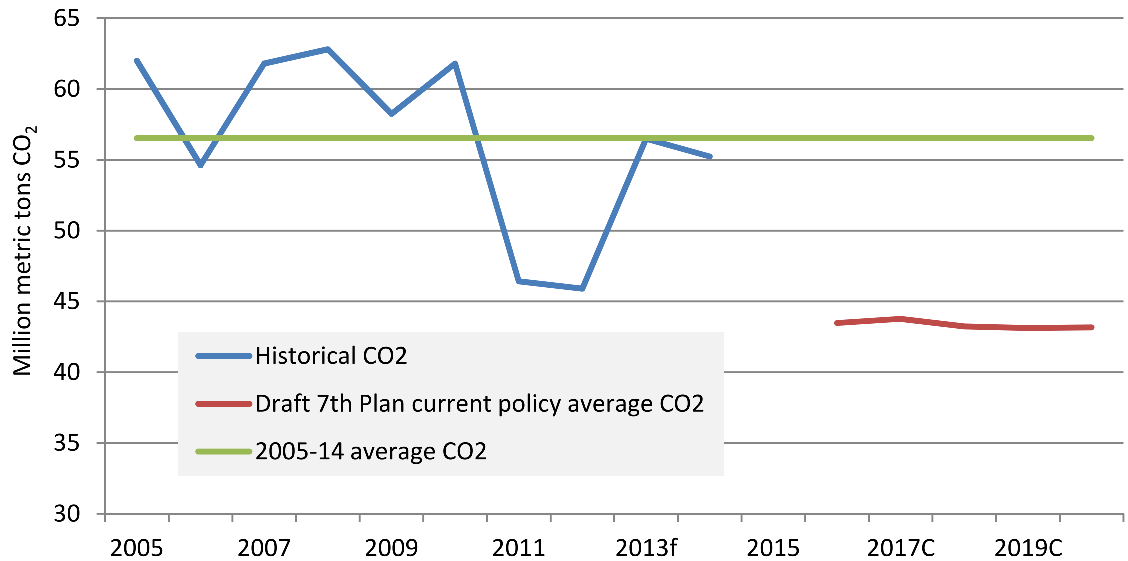

Figure 3 – Historical CO_2 v. 7th Plan business as usual forecast

PNUCC has investigated this issue and finds that the difference between historical and draft Plan forecasted emissions is likely due to two factors:

1. Gas and coal units under dispatch in the regional portfolio model as compared to historical data. Table 2 shows average historical dispatch from 2005-14 and the average dispatch during the first five years of the 1B scenario. The difference between the draft Plan's dispatch and historical dispatch alone reduces CO_2 emissions by an estimated 6.7 million metric tons per year.[12]

MWa	2005-14 hist. avg.	2016-20 1B avg.	Delta
Gas	2,783	1,902	(881)
Coal	4,947	4,535	(412)
Total	7,730	6,437	(1,293)

Table 2 – Historical dispatch v. 7th Plan

[12]Assuming carbon intensity rates of 1 metric ton per MWh for coal and 0.4 for gas. Historically, the Northwest coal fleet averages 1 metric ton per MWh, whereas the gas fleet averages slightly above 0.4 metric tons per MWh

2. Gas and coal heat rates appear to be low in the draft Plan's analytics. Using the 1B dispatch average above, and assuming intensity rates of 1 metric ton per MWh of coal and 0.4 of gas, average emissions from 2016-20 would be 46 million metric tons per year, 3 million metric tons higher than the RPM's 2016-20 estimates. In addition this estimate does not include any additional CO_2 produced by units identified as "must-run." This issue might be due to the use of minimum heat rates in the regional portfolio model whereas in reality actual heat rates will vary based on many factors (start-stops, ramping, etc).

PNUCC supports the Council in making carbon reduction a central focus of the 7th Plan. However, we ask that the results are rechecked to insure that the estimates of future CO_2 emissions are accurate and reasonable. The exact emissions may not impact the comparison between scenarios, but it does impact the Plan's usefulness for examining the region under alternative carbon policies. If the Plan presents unrealistic estimates of emissions it should not be used to draw conclusions regarding the Northwest's, or individual states, ability to comply with carbon regulations. Therefore, PNUCC recommends that the Council explain why there seems to be a large discontinuity in projected carbon emissions in comparison to historical data or make appropriate adjustments to the RPM analysis for the final plan. [13]

Carbon leakage issues should be explored

A quick glance at the 7th Plan may draw readers to conclude that carbon pricing has a huge impact on emissions. In some ways this is correct – shifting the dispatch order of resources via pricing can reduce coal generation and increase gas generation, thus decrease emissions as natural gas power plants typically emit 2 to 3 times less CO_2 per megawatt hour than coal. However, the draft plan did not fully explore "carbon leakage," another effect of a Northwest carbon tax.

Table 3 shows that the social cost of carbon scenario (2B) in 2016 estimates that total system carbon emissions are 20 million metric tons, as compared to carbon emissions of 43 million metric tons under the current policy scenario (1B). At first blush, this seems like a 50% or more decrease in carbon emissions. However, modeled exports are also down 2,000 MWa. The extra-regional demand that was being met by power exported from the region does not go away due to assumed imposition of a Northwest carbon tax. Instead, dispatchable non-Northwest units would pick up the demand, and generate additional CO_2 emissions outside the region. This leads to "carbon leakage:" while emissions go down in the Northwest, the carbon will leak out into other regions as they have to run other thermal resources to replace lost Northwest power.

If the 2,000 MWa of reduced exports are picked up out-of-region by efficient gas units, those units will generate around 7 million metric tons of CO_2 per year. Because CO_2 is a global pollutant – the effect is the same if emitted in the Northwest, or elsewhere in the West. By omitting the regional CO_2 effects of

[13] EIA data. The 7th Plan may have a slightly different data set as its 2001 to 2012 CO_2 average is 55 million metric tons, not 56.5 million metric tons as in the PNUCC 2005-14 average. Regardless, the drop from the Council's 55 million metric ton average to 43 million metric tons in 2016 of is significant. Also note that total power system includes Jim Bridger and 50% of North Valmy

exporting less, carbon pricing appears to reduce emissions more than it would in reality. The plan cannot precisely calculate Northwest carbon leakage, but the issue should at least be discussed.

	2016 CO2 (MMTE)	2016 Exports (MWa)
Scenario 1B - Current policy	43	4,298
Scenario 2B - Current policy + SCC tax	20	2,338
Delta, 2B minus 1B	(23)	(1,960)

Table 3 – CO_2 falls with Carbon tax, but so do exports

Natural gas price forecast looks high

PNUCC understands that the planning process requires that the natural gas price forecast was locked in early in the Plan development process. Because the nature of the natural gas industry in changing rapidly, this forecast now looks high. The natural gas forecast was finalized in July 2014 – well before most of the draft plan's inputs were finalized. It sets a medium price forecast for 2015 at around $4.00 per MMBTU ($2012), and builds upwards from there. The high end of the forecast range eventually reaches over $10.00 per MMBTU, while the low end of the forecast drops to around $3.00. Beyond the range the RPM also alters the forecast using seasonality and jump logic. This can create some strange pricing – for example in the first quarter of 2016 there are futures where the draft Plan sees gas prices exceeding $9/MMBTU.

For the better part of 2015, natural gas has traded under $3.00 per MMBTU. Looking at commodity futures prices, gas is expected to continue to average under $3.00 per MMBTU for the next two years.[14] The US EIA winter 2015/16 fuel forecast is predicting gas prices to be roughly $0.40 lower this winter than last. Figure 4 shows the draft Plan's mean gas price forecast in red and the 10%-90% price range in the model in light blue. The black dashed line represents current gas futures – note that futures volumes are thin in 2017 so these estimated prices are less certain.

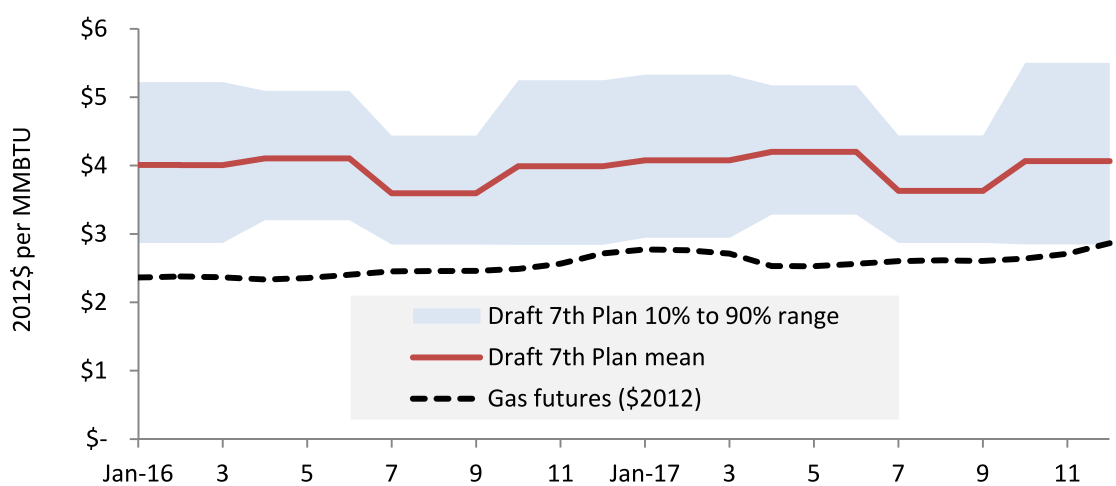

Figure 4 –Draft 7th Plan gas prices and future prices

[14] Futures data collected from CME on Nov 3, 2015. 7th Plan data from workbook "ngas_futures-seventhplan-rpm"

Gas prices play an important role in setting electric market prices as gas tends to be the fuel on the margin. As a result, along with gas prices, the wholesale electricity prices in the draft Plan look high. Page 5 of chapter 1 in the draft Plan notes that "by 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars." Despite more zero marginal cost resources being built in surrounding regions, and the persistence of cheap gas, wholesale power prices in the draft Plan range never reach levels experienced today (the 2015 average to date is well under $30/MWh), nor do they ever decline in real terms.

Natural gas prices can change the regional portfolio and the recommended course of action. The figure below shows the six year energy efficiency targets for scenarios 1B and 2C with the base gas prices, and then again with low gas prices. Although the low prices do not have a significant affect in Scenario 1B, the affect in Scenario 2C (with carbon pricing) is approximately 100 MWa. This is another reason for the plan's energy efficiency goals to be specified as a range, rather than a fixed number.

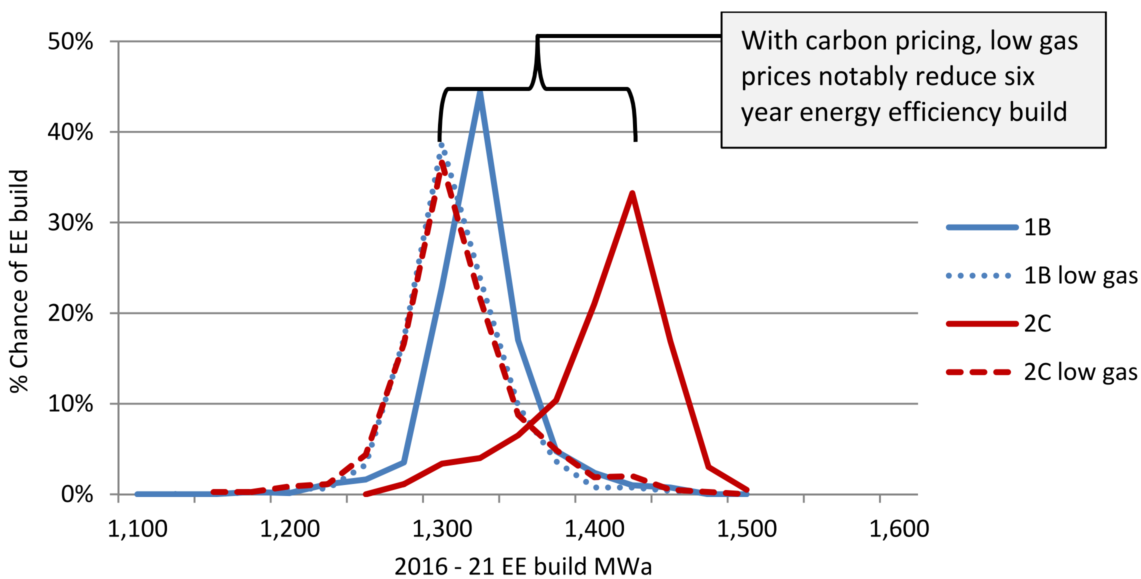

Figure 5 – Gas price impact on EE development

PNUCC recommends adjusting the gas price forecast for the final Plan, particularly the first few years, to reflect current market conditions. Many other organizations have been lowering their gas price forecast to better reflect today's gas markets.[15] Going forward, the Council should consider blending in commodity strips into the early years of their gas forecast to better reflect current conditions, and should consider reducing the forecast uncertainty in the first few years as well.

[15] Ex. Moody's recently cut their gas price forecast. Their new forecast stays under $3 through 2018 (in $2012) https://www.moodys.com/research/Moodys-lowers-oil-price-assumptions-on-oversupply-and-weakening-demand--PR_336879

Transmission and distribution valuation method has issues

PNUCC is concerned with the method used in the draft Plan to calculate the transmission and distribution deferment value that is applied to demand-side resources and some west-side supply side resources. The chosen transmission and distribution savings values represents the average cost of data collected from a wide assortment of utilities, some in the Northwest, and others in California, Indiana, Missouri and Texas. Cost estimates from Bonneville, one of the Northwest's largest transmission providers, are not used. In sum, the value, which is attached to many resources in the analysis, seems to have been formulated with limited Northwest data.

Table 4 shows how the value is calculated – note that most utilities listed are out of region:

Transmission			**Distribution**		
Utility/Area	Average 2006$/KW-yr	2012$/kW-Year	Utility/Area	Average 2006$/KW-yr	2012$/kW-Year
SDG&E (CA)	$18.80	$21	CPL (TX)	$44.27	$49
SCE (CA)	$51.70	$57	KCP&L (MO)	$7.48	$8
PG&E (CA)	$13.56	$15	PG&E (CA)	$21.26	$24
CA - Avg. (CA)	$18.03	$20	PSI (IN)	$5.81	$6
S. Cal (CA)	$16.60	$18	PSE - Ave	$9.67	$11
N. Cal (CA)	$21.30	$24	PacifiCorp	$76.17	$84
PacifiCorp	$29.42	$33	PGE	$20.37	$23
PGE	$9.87	$11	SnoPUD 2013	(not included)	$42
Average	$23.10 (sic)[16]	$26 (sic)	Average	$24.70 (sic)	$31

Table 4 – The draft 7th Plan's T&D cost calculations are lacking firm methodology (items in parentheses added by PNUCC)

Beyond the non-Northwest assortment of utilities, the data used in the calculation are in need of an update. Some of the data are from 1999, and costs change over time.[17] For example, PacifiCorp has a combined transmission and distribution deferral value of $117 in the draft 7th Plan (date unknown). However, in their 2015 integrated resource plan they estimated the value to be $52 ($2012).[18]

Lastly, the draft Plan applies the avoided transmission and distribution deferment value to all demand response and conservation resources, regardless of location, and some west side supply side resources as well. Transmission and distribution upgrades are lumpy – upgrades occur when the system load reaches a critical point. Today, there are some transmission and distribution systems on the edge of needing upgrades that likely see a transmission and distribution savings value from energy efficiency and/or demand response. There are also systems that are years away from needed upgrading even if no

[16] Three of the averages in the draft 7th Plan T&D deferral value calculation are incorrect, as noted in Table 4
[17] Cost data from four inputs (CPL, KCP&L, PG&E and PSI) comes from the 2000 Energy Foundation report "Cost Methodology for Electric Distribution System Planning," which notes that its data are from 1999.
[18] PacifiCorp 2015 IRP, Volume 1, page 124.

conservation and/or demand response are acquired. The draft Plan, however, assumes that all systems are on the brink of needing an upgrade, and gives a deferment value regardless of location.[19]

The draft Plan's transmission and distribution deferral value calculations are not grounded in Northwest transmission and distribution data and are in need of an update. While this may not overly affect the resources strategy in the Plan within scenarios, it does affect the plan's cost estimates, and could change the relative ranking of various scenarios. Perhaps most importantly, it raises concerns about the rigor of the Plan's input assumptions and analysis. PNUCC recommends creating an action item to update the transmission and distribution deferral value for future Council studies, and would be happy to assist in the process.

Energy efficiency cost effectiveness methodology illustrative only

Appendix G of the draft Plan includes the draft Plan's energy efficiency cost effectiveness methodology and an accompanying formula. From conversations with Council staff PNUCC understands that this formula is for illustrative purposes only, and that each utility will use their own methodology for determining energy efficiency cost effectiveness. However, Appendix G states also that "Conservation program managers, the Regional Technical Forum, and regulators should use the benefit/cost ratio method outlined below to determine cost-effectiveness." The draft Plan then lists the recommended equation and defines the variables being used. PNUCC recommends striking the language instructing usage of the proposed methodology and expressly acknowledging that utilities may calculate energy efficiency cost effectiveness using different methodologies and/or inputs.

Many utilities will use methods and inputs that differ from the draft Plan's cost effectiveness formula. Some utilities will assess energy efficiency cost effectiveness using a portfolio modeling approach rather than using a formula. Most utilities will have different inputs than those used in the draft Plan as well. For example, the draft Plan uses an aeroderivaitve gas unit as its deferred capacity cost proxy, which is not appropriate for many utilities (see page 7 of this document for a discussion on this issue).

Associated System Capacity Contribution estimate for model alignment only

The Council introduced the Associated System Capacity Contribution (ASCC) concept in summer 2015 in an effort to better align the GENESYS and Regional Portfolio Model (RPM). Prior to the use of the ASCC the RPM was habitually overbuilding the power system. While PNUCC supports the Council aligning the analysis of all the models, the Council should recognize this as a model alignment exercise, not an estimate of a fundamental resource trait.

The Council notes that the ASCC "reflect(s) the fact that energy produced by generating resources or saved by energy efficiency resources can be used to store water in the hydro system for later use to meet peak demands."[20] While there is an interaction between new resources and the hydro system, the

[19] The deferral credit also assumes that all T&D systems see their peak at 6 PM on a weekday in the winter. Some systems may see a peak in the spring/summer depending on exports and time of peak.
[20] Dec 8, 2015, Council memo: http://www.nwcouncil.org/media/7149797/p1.pdf

Council's tool for calculating this, GENESYS, cannot accurately capture the impact of this interaction for all new resources.

Although GENESYS is a useful tool for providing insights into Northwest resource adequacy trends, it does have a number of handicaps. Similar to the RPM, it assumes that the region dispatches as one large utility, and that the Northwest hydro system is optimized to meet the load of both public utilities and investor owned utilities. It also does not have the ability to sell/export resources out of the Northwest. As such, it likely overstates the hydro interaction of new investor owned utility resources, and overestimates how much water/fuel is saved due to the addition of new resources that could possibly be sold as short term non-firm energy out-of-region.

Although aligning the models used in the plan's analysis is an important analytic step, PNUCC has concerns that the results of the ASSC analysis may be inappropriately used. While there are interactions between all new resources and the greater power system, GENESYS as currently structured fails to realistically capture how the region's power markets operate. Our concern is that some may claim that because of system interactions, all new combined cycle combustion turbines should get an increase of 30% over nameplate capacity and energy efficiency should get an additional 20%, which would be in error. Many utilities and organizations turn to the Council for data, and they should not be under the impression that the GENESYS derived ASCC values are appropriate for any use other than to align the analysis conducted by the Council's models. The 7th Plan should clearly note that the ASSC values are for model alignment only and cannot be interpreted as inherent characteristics of new resources.

Price elasticity of demand lacking from analysis

Within the scenario modeling, demand for electricity in the draft Plan is not responsive to electricity prices which could give misleading results. Price elasticity of demand pertains to how demand is influenced by price. Typically, if the price of a good increases, the amount of the good purchased decreases. Electricity is an inelastic good – a 10% increase in the price of electricity will likely result in a less than 10% decrease in electric usage. Still, as the price of electricity increases, the amount of electricity the end user consumes will decrease.

Although the Council takes price effects into consideration when creating the regional load forecast, once the forecast is created and entered into RPM, demand is no longer affected by price (although the amount of cost effective energy efficiency can vary based on price). In some scenarios, such as the 95% social cost of carbon or retiring all high heat rate units, consumers and industry would see higher rates, leading to decreased electricity consumption. This would in turn affect outputs including emissions and need for resources.

By not reflecting price elasticity of demand, results from scenarios that differ substantial from current policy are less realistic and difficult to compare to other scenarios. While the final plan likely cannot capture this interaction within the current analysis framework, it should be an issue addressed in future Council work.