BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 57

In the Matter of	)
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PACIFICORP	)
dba PACIFIC POWER	)
	)
2013 Integrated Resource Plan	)
	)

OPENING COMMENTS OF THE
CITIZENS' UTILITY BOARD OF OREGON

August 22, 2013

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The Citizens' Utility Board of Oregon (CUB) appreciates the opportunity to comment on PacifiCorp's (the "Company") Initial Application of its Integrated Resource Plan (IRP). CUB's comments will focus on the following three areas: 1) PacifiCorp's treatment of energy efficiency, 2) PacifiCorp's analysis of coal investments, and 3) PacifiCorp's assumptions related to transmission investments.

I. Energy Efficiency

CUB's primary concern with PacifiCorp's approach to energy efficiency relates to PacifiCorp's treatment of accelerated demand-side management (DSM). The Company stated in its IRP workshop on March 21, 2013, that cases EG1-C15 and EG2-C15, which both included accelerated DSM, "yield the highest ranking risk adjusted net PVRR."[1] Page 222 of the IRP also acknowledges that these scenarios were highly ranked. Notwithstanding this high ranking, the

[1] 2013 Integrated Resource Plan IRP Modeling and Results Update Draft Preferred Portfolio at pg 17 (March 21, 2013). Accessed at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_PIM18_PrefPort_3-21-13.pdf

Company decided to not prioritize these portfolios because it felt that it did not have either strong evidence to demonstrate the true acquisition costs for DSM or that the revised ramp rate assumptions would be achievable.[2]

A. Oregon Results Show Additional Energy Efficiency is Achievable

PacifiCorp only has to look at a diagram of Oregon's historical energy usage to see strong evidence that additional energy efficiency is achievable.[3] Oregon has demonstrated a decreasing trend in average residential usage over the past two decades.[4] And, as *Table 1* reveals, PacifiCorp is implementing energy efficiency at a greater rate in Oregon via the Energy Trust than it is in other states using its own in-house programs. This review of Oregon's energy efficiency achievements demonstrates that the possibilities for energy efficiency in other locations, including Oregon, should be more intensely investigated.

The Table below compares actual DSM results from 2012 as a percentage of forecasted weather-normalized 2013 load and demonstrates that the Company is achieving significantly more DSM in Oregon than in other states:

[2] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 222.
[3] *See* Figure 1.
[4] *Ibid.*

Table 1 – Annual Forecasted Load and Actual DSM[5]

	Forecasted Annual Growth in kWh (2013)	Actual DSM Achieved in kWh (2012)	DSM percentage of load
California	903816000	6396303	0.71%
Idaho	3740820000	12614617	0.34%
Oregon	14877800000	211758474	1.42%
Utah	25153750000	236248188	0.94%
Washington	4453504000	49781945	1.12%
Wyoming	10190043000	23253965	0.23%
Total	61556386000	540,053,492	0.88%

The percentages in Table 1 are based on forecasted 2013 load[6] and total historical DSM for 2012. As Table 1 demonstrates, Oregon most aggressively implements DSM, achieving results that are more than 60% greater than the system as a whole (including Oregon). For example, although Utah's total load is 60% greater than Oregon's total load, DSM supplies 0.94% of total load in Utah while in Oregon the corresponding figure is 1.42%. Oregon's programs, administered by the Energy Trust of Oregon (ETO), have impressive results, especially when compared to the other states. CUB believes that the energy savings of implementing ETO-comparable programs in Utah or other states could mean thousands of MWh saved and a more cost-effective energy resource for PacifiCorp customers system-wide, particularly if new load growth is met through DSM as opposed to new generation. PacifiCorp should be making more investments in energy efficiency. PacifiCorp's Oregon results

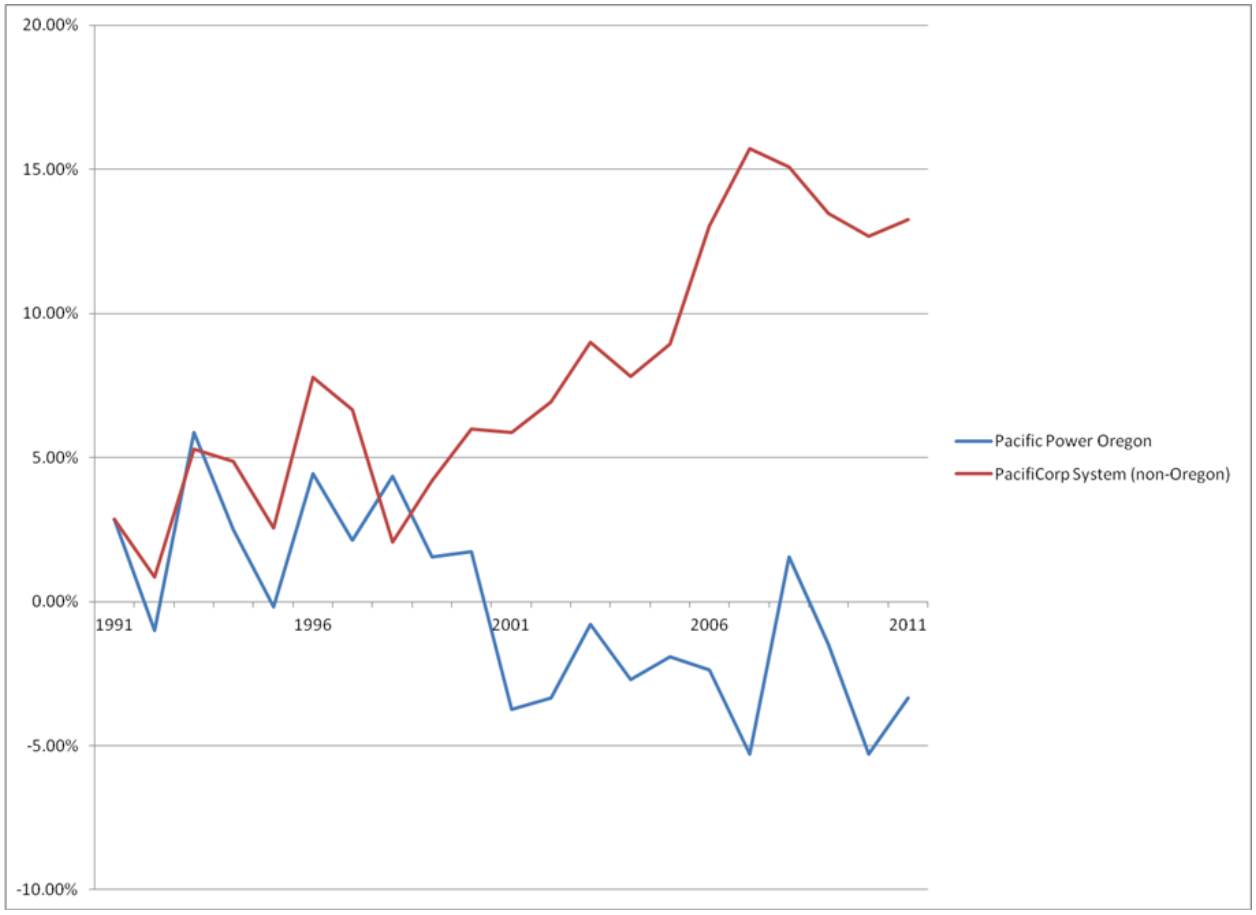
[5] Information for Table 1 is sourced from PacifiCorp's Response to CUB DR 11 (CUB Attachment C) and pg. 11 of Appendix A, PacifiCorp IRP Volume II.

[6] LC 57 - 2013 Integrated Resource Plan, Appendix A, Table A.1 – Forecasted Annual Load Growth, 2013 through 2022 (Megawatt-hours).

demonstrate that not only can it surpass its own goals for other states,[7] but also that accelerated DSM scenarios are in fact the least-cost.

The amazingly positive effects of Oregon's energy efficiency programs over time can be seen by looking at the change in average residential usage since 1990. Oregon's average residential usage has declined while the combined results for other states show an increase.[8]

Figure 1 – Change in Average Residential Usage since 1990[9]



[7] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 259.
[8] CUB recognizes however that Data Response 2 from the Company (CUB Attachment A), does show a significant decline in Idaho.
[9] Oregon Utility Statistics, OPUC, 1990-2013.

B. The Action Plan's Commitment to DSM is Confusing.

Despite not selecting either of the recommended accelerated DSM scenarios, the Company stated in its March 21, 2013 workshop that it acknowledged the potential benefits of accelerated DSM and that it would consider action items incorporating accelerated DSM to mitigate front office transaction (FOT) purchases. Pages 257-259 of the IRP list these action items, one of which was a pilot program offered in collaboration with the ETO. Even with these changes, it remains unclear from the IRP, as well as PacifiCorp's workshop on March 21, 2013, what kind of effects the accelerated DSM would have on the chosen scenario. CUB is concerned as to whether the Company's treatment of accelerated DSM was properly incorporated into the IRP. Because accelerated DSM is not included as part of scenario EG2-C07a, the Company's selected portfolio,[10] it is unknown what kind of impact accelerated DSM would have on FOT and other resources. Furthermore, given that the Company has not stated an increased goal for DSM, CUB is left to assume that the goal may not have changed from its 2011 and 2012 goal of achieving 845,036 MWh of Class 2 DSM acquisition.[11] If the Company is adding additional DSM to its preferred portfolio the Company should show additional results from DSM.

CUB is concerned about the implications of the Company rejecting a least-cost scenario because of the uncertainties associated with DSM.[12] PacifiCorp explains in its IRP that it is capable of exceeding its Class 2 DSM acquisition goals by at least 29%, or 242,438 MWh.[13] Moreover, the Company has historically demonstrated that it possesses the ability to achieve more energy efficiency than forecasted. So why is it not pursuing accelerated DSM?

[10] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 225.
[11] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 259.
[12] *See* LC 57 - 2013 Integrated Resource Plan, Volume I at pg 225.
[13] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 259.

While CUB is very pleased that the Company has been able to surpass its own DSM goals, CUB is also disappointed that PacifiCorp apparently failed to consider its own historical energy efficiency results when deciding not to pursue an accelerated DSM scenario. CUB recommends that the Company consider modeling different strategies, such as ETO-comparable programs in other states.

PacifiCorp's modeling once again demonstrates that the cheapest resource for meeting load growth is energy efficiency, but PacifiCorp rejected the least-cost portfolio as not achievable. The experience from historic results in all states, and ETO results in Oregon, suggests that the Company can achieve greater DSM than it is proposing. For these reasons, CUB is asking that the Commission not acknowledge the DSM section of PacifiCorp's IRP.

II. CUB'S Response to PacifiCorp's Coal Investment and Confidential Coal Study

A. Introduction to CUB's review of Coal Issues.

While CUB is encouraged that PacifiCorp is finally voluntarily considering clean air compliance costs as an issue in an IRP, and has improved its modeling of coal investments and alternatives to those investments, CUB remains concerned that PacifiCorp's modeling is biased in favor of billions of dollars of investments in coal plants. With PacifiCorp's bias, there is a significant risk that investments will be made that are not least-cost/least-risk. In particular, there is a risk of future stranded costs if coal plants are retired after billions of dollars of new investments are added to those plants.

It is also important to note that PacifiCorp still fails, in both the IRP and the confidential coal study, to look systematically at the Company's coal fleet in order to identify how the coal plants would operate in a world with climate regulation. The IRP filing was itself limited to examining the coal regulations that PacifiCorp reasonably anticipated when it began the IRP

process, and the Coal Study was limited to looking at the handful of plants requiring imminent decisions. Unfortunately for PacifiCorp, this means that the world passed it by. The filed IRP analysis was not even robust enough to accommodate the Regional Haze Federal Implementation Plan (FIP) that the EPA issued last June,[14] nor the EPA's proposed regulation of carbon emission from existing plants. In addition, future regulations and implementations of carbon control will likely be stronger and will likely fall within the timeline of the useful life of the coal investments that the company chose to put forward for consideration in its IRP.

There are serious problems with PacifiCorp's IRP approach to coal investment:

1. The parameters that the Company used to model Regional Haze Investments were too narrow to evaluate the expected costs.

2. The economic lives of clean air investments that the Company used were not consistent with the lives of the plants - this could lead to overinvestment in clean air technologies.

3. In looking at alternative closures (what CUB refers to as phase-outs), the Company misapplied the EPA's cost-effectiveness limit.

B. The parameters that the Company used to model Regional Haze Investments were too narrow to evaluate the expected costs.

PacifiCorp modeled two scenarios relating to Regional Haze Requirements on its coal fleet: a base case and a stringent case. Unfortunately, the currently proposed Federal Implementation Plan for Wyoming requires significantly more investment than the Company's stringent case.

Integrated Resource Plans take months to complete. During that time real-world events (natural gas prices, load growth) likely vary from the modeling assumptions. For this reason, good planning involves the use of multiple forecasts so that the IRP will continue to be useful

[14] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34738 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52). Accessed at: http://www.gpo.gov/fdsys/pkg/FR-2013-06-10/pdf/2013-13254.pdf

even as events change. For example, the use of high, medium, and low natural gas prices allows for review of how different scenarios will perform if the base case assumption is incorrect. When Portland General Electric was analyzing its pollution control investments in Boardman, in addition to its base case assumption for natural gas prices, it produced a low and a high scenario.[15] During the course of that planning process, prices for natural gas fell below the Company's base case.[16] However, because PGE had analyzed the portfolios under a low gas assumption, parties could see how the change in gas prices affected the scenarios without a need to stop the IRP and update the IRP's assumptions.

The goal of high and low cases should be to ensure that the parameters are set wide enough to contain the likely future. These outside parameters will encompass various events that will not come to pass. However, the wide range of options in modeling increases the probability that the realized event will fall within the modeled possibilities. If the parameters are too narrow, a shift in gas prices could lead to prices that are outside of the IRP analysis, reducing the usefulness of the results.

This is exactly the problem that exists with PacifiCorp's analysis of Regional Haze Investments. Both the base case and the stringent cases underestimate the potential costs. The base case assumes that the EPA accepts the State of Wyoming's proposed State Implementation Plan. The EPA has rejected the Wyoming SIP,[17] and the stringent case simply does not assume the level of investment that EPA has proposed. The projected costs of regional haze are now outside the parameters that were reviewed in the IRP.

[15] *See Re: Portland General Electric Company*, Docket LC 48, OPUC Order No. 10-457, 6-7 (Nov. 23, 2011).
[16] *See ibid.*
[17] *See* Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34738 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

C. The economic lives of clean air investments that the Company used were not consistent with the lives of the plants - this could lead to overinvestment in clean air technologies.

PacifiCorp's coal units were constructed over a period of decades. The remaining useful lives of the plants vary widely:[18]

Table 2 – Useful lives of PacifiCorp's coal units

Unit	Assumed end of Life Year
Carbon 1 &2	2014
Dave Johnston 1-4	2027
Naughton 1&2	2029
Hayden 1&2	2030
Huntington 1&2	2036
Jim Bridger 1-4	2037
Wyodak	2039
Hunter 1-3	2042
Cholla 4	2042
Colstrip 3&4	2046

For pollution control equipment relating to regional haze, PacifiCorp uses the EPA's assumption of a default useful life of 20 years, which would begin 5 years after federal approval of the SIP or FIP. If one were to assume that the EPA's FIP will be approved this year for the Dave Johnston and Naughton units, the assumed end of the useful life of the regional haze pollution control would be 2038 (2013 + 5 + 20). This is 11 years after the end of the assumed useful life of the Dave Johnston units and 9 years after the end of the assumed useful life of the Naughton units. Between these two units, this would amount to a total of 20 years of pollution control investments that would be made, but the pollution itself would never be removed through these regional haze investments.

[18]LC 57 - 2013 Integrated Resource Plan, Volume I, Table 5.3.

i. This leads to higher pollution control costs.

The EPA evaluates the cost-effectiveness of various pollution control options by comparing them in terms of the dollars/ton of pollution removed over the lives of the pollution control investments.[19] For the Dave Johnston plant, the pollution control would need to be installed by 2018, and its cost-effectiveness would be based on the amount of pollution that those controls would remove from 2018 to 2038. As the chart above demonstrates, PacifiCorp's IRP models the Dave Johnston units as closing in 2027. Thus, there is no pollution to remove for the decade following the closure of the plant. PacifiCorp had the option of using the real, expected life of the plant as the life of the pollution control. The EPA would have evaluated the pollution control based on 9 years of removing pollution rather than 20 years, and this would likely have led the Company to the conclusion that investing in less pollution control would have been the most cost-effective option.

ii. Are these higher dollar costs valuable?

It could be argued that incurring higher pollution control costs is worthwhile because it will allow the underlying coal plant to run past its expected useful life. While the IRP does model Dave Johnston closing in 2027 and Naughton 1 & 2 closing in 2029, the ends of their projected lives do not necessarily match up with the ends of their economic lives. In order for PacifiCorp to justify 20 years of pollution control costs being added to plants expected to retire before the 20 year period is over, PacifiCorp must show that the potential value of the additional years of coal generation (or the potential option of continued coal operation) is greater than the additional pollution control expense. If PacifiCorp can demonstrate that the 20 years of "lost"

[19] *See e.g.* Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34754 at Table 1 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

pollution control (11 for Dave Johnston and 9 for Naughton) is still a cost-effective investment because it creates the option to run the coal plant longer, then this would be a reasonable strategy that should be acknowledged in the IRP. However, PacifiCorp is not presenting any evidence that demonstrates that the pollution control technology is adding any additional benefit. Instead, PacifiCorp is simply adding 20-years of pollution control measures to plants that are assumed to last only half of that time.

D. In looking at alternative closures (what CUB refers to as phase-outs), the Company misapplied the EPA's cost-effectiveness limit.

CUB has been encouraging the Company to consider phasing out its coal units as an alternative to running them up to an environmental deadline and then closing them relatively suddenly as the deadline approaches. As part of its coal study, the Company attempted to do the following analysis:

 [20]

A similar analysis by PGE in 2009 led PGE to seriously consider phasing out the Boardman coal plant.[21] PGE's analysis showed that phasing out the plant by the end of 2020 rather than investing in the full requirement of regional haze controls reduced the regional haze investments and achieved lower overall costs for its customers.[22] Not making the full regional

[20] LC 57 - 2013 Integrated Resource Plan, Confidential Volume III at pg 1-2.
[21] *See Re: Portland General Electric Company*, Docket LC 48, OPUC Order No. 10-457, 7-17 (Nov. 23, 2011).
[22] *Ibid.*

haze investment and running the Boardman plant until the end of its assumed useful life was ultimately found to be cheaper than making the full regional haze investments.[23]

CUB is encouraged that PacifiCorp has finally acknowledged that there is enough flexibility under the Regional Haze Rules to consider such an early closure alternative and that, under some conditions, this alternative may be the lowest cost for customers. But it is very disappointing to CUB to consider (1) just how many years have passed since PGE first did its analysis and determined that early shut down would be cheaper, and (2) that during all those lost years PacifiCorp has spent hundreds of millions of dollars on regional haze investments. In fact, PacifiCorp's acceptance of the early shut down theory is so new that the Company has only considered possible early closure for a very small number of its coal units. Frankly, CUB had hoped that the Company would have identified which units were most promising for a phase out approach well before 2013.

i. PacifiCorp focuses on incremental cost-effectiveness of SCR investments rather than the cost effectiveness of NO_x control technologies.

[redacted] In PacifiCorp's Response to Staff Data Request 23 (CUB Attachment B), the Company defended the [redacted] figure by pointing to the EPA FIP related to Naughton 1 and 2 and Dave Johnston Unit 3:

> The most recent and specific references to costs per ton that the U.S. EPA has deemed supportive of installation of SCR are those associated with the Regional Haze Federal Implementation Plan EPA proposed in Wyoming on May 23, 2013, which was published in the Federal Register June 10, 2013 (See, 78 Fed. Reg. 34738 – 34794). In that plan, EPA has proposed to require the installation of SCR on Naughton Unit 1, Naughton Unit 2 and Dave Johnston Unit 3. All of these

[23] *Ibid.*

units are currently equipped and operating with low-NO_x burners with separated over-fire air. The table below identifies, using EPA's costs and emission reductions, the costs of adding the SCRs to these units in terms of dollars per ton of NO_x removed. (The costs and emissions reductions used for these calculations reflect EPA's perspective on this issue. PacifiCorp believes EPA has significantly underestimated the applicable SCR costs for these installations.)

Unit	Dollar per Ton of NO_X Removed Going From LNB-SOFA to SCR
Naughton Unit 1	$5,869
Naughton Unit 2	$5,960
Dave Johnston Unit 3	$5,992

In the same document issued May 23, 2013, and published June 10, 2013, EPA also requires SCR on the four Jim Bridger Units. Low NO_x burners with separated over-fire air are installed and operational on these units. The table below identifies, in terms of dollars per ton of NOx removed, the costs of adding the SCRs to these units using EPA's costs and emission reduction calculations. (Again, the costs and emissions reductions used for these calculations reflect EPA's perspective on the issue.)

Unit	Dollar per Ton of NO_X Removed Going From LNB-SOFA to SCR
Jim Bridger 1	$5,880
Jim Bridger 2	$6,717
Jim Bridger 3	$6,141
Jim Bridger 4	$5,616

This is not consistent with how the EPA analyzed BART with respect to the Naughton, Dave Johnston, or Jim Bridger units. For example, for Jim Bridger 1, the EPA identified the cost of a new low-NO_x Burner with Overfire Air with a selective catalytic reduction (SCR)as $2393, not $5880.[24] For the Naughton units, the EPA found the cost effectiveness of pollution controls including the SCR to be much lower than PacifiCorp's figures:

> EPA's cost analysis estimated the cost-effectiveness value for LNBs with OFA and SCR at Unit 1 is $2,318/ton with a 1.23 dv visibility improvement at the most impacted Class I area. The cost-effectiveness value for LNBs with OFA and SCR

[24] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34754 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

at Unit 2 is estimated at $2,255/ton, with a 1.42 dv visibility improvement at the most impacted Class I area.[25]

The EPA found that the SCRs were cost-effective at Naughton 1 & 2 because those SCRs were part of a set of pollution controls that cost between $2,255 and $2,318/ton; these figures are clearly within the EPA's normal cost effectiveness limit. The difference between the EPA's finding of cost-effectiveness at less than $2500/ton and PacifiCorp's claim of cost-effectiveness at approximately [redacted]/ton is that PacifiCorp is attempting to identify the cost-effectiveness of a stand-alone SCR while EPA never considered a stand-alone SCR as a potential candidate for Best Available Retrofit Technology (BART).

The EPA considered three technologies to identify the Best Available Retrofit Technology (BART): for Naughton 2 NO_x controls, the EPA considered new low-NO_x burners (LNB) with Overfire Air (OFA), new LNB with OFA and SNCR, and new LNB with OFA and SCR:[26]

Table 2 – Cost Effectiveness of BART Technologies[27]

Control Technology	**Emission Rate (lb/MMBtu)(annual average)**	**Annualized Cost**	**Average Cost-Effectiveness ($/ton)**
New LNBs with OFA	0.21	$883,900	$342
New LNBs with OFA and SNCR	0.16	2,510,049	830
New LNBs with OFA and SCR	0.05	8,843,387	2,255

[25] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34783 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

[26] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34782 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

[27] Information in Table 2 sourced from: Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule, 78 Fed. Reg. 34782 (proposed June 10, 2013) (to be codified at 40 C.F.R. pt. 52).

The issue for the EPA is not the cost-effectiveness of an SCR, but rather the cost-effectiveness of the comparative control technologies that the EPA considers candidates for the "best available." Since an SCR on a stand-alone basis is not a control technology that is being considered, its incremental cost-effectiveness is not the deciding factor. An SCR combined with LNB and OFA creates a significant visibility improvement, and together they are cost-effective; it was chosen by EPA as the best available technology for this reason.[28] This also shows the risk that PacifiCorp is taking by rushing ahead and installing pollution control equipment before EPA has made a decision. PacifiCorp was hasty to install an LNB with OFA on the Naughton units without the EPA having acknowledged that such technology met the BART standard. PacifiCorp may have hoped that once the LNB with OFA was installed, the EPA would have to look at an SCR as a stand-alone technology, but the EPA is looking at improving emissions from a baseline period from before PacifiCorp's installation of the LNB with OFA. The EPA cannot give PacifiCorp credit for installing the LNB with OFA and measure BART from that point forward (making the SCR an incremental addition) because it would allow companies to avoid the best available retrofit technology by making installations less than the best available in order to preempt EPA from requiring the best available. If a company can install something that is cheaper and removes less pollution, but removes enough pollution such that the best available retrofit technology no longer is cost-effective, then the Regional Haze Rules would have a significant loophole. It is not surprising that this is not EPA's interpretation of the rules.

PacifiCorp's assumed cost-effectiveness limit of [redacted]/ton is not supportable. EPA does not base cost-effectiveness on incremental technologies, but rather bundles of technologies that it considers best available candidates. In looking at the best available, the EPA's cost-effectiveness

[28] *See ibid.*

limits are well below [redacted]/ton. For these reasons CUB believes that the Company has failed to meet its burden of proof to show that these investments are indeed the least-cost/least-risk.

ii. In a phase out scenario, it is important to consider BART technologies.

In its hypothetical phase-out study, PacifiCorp should have focused on the control technologies that EPA considers and not on SCRs. Take for example the two Naughton plants, where the pollution control technology must be installed by 2017-2018. Using the current 20-year life for the pollution control assumes that the plant will run until 2038, nine years longer than its current life. By closing the plants early (but sometime after 2018), the installed pollution control technologies would have less pollution to remove, and the installed pollution controls would therefore be less cost-effective. This is true not just for the SCR, but also for the LNB with OFA and, more importantly, LNB with OFA and SCR. All of these pollution control technologies would have less pollution to remove if the plants closed early and they would therefore not be cost-effective to install.

There are three control technologies that EPA is considering as BART for NO_x at Naughton 1 and 2: 1) LNB with OFA, 2) LNB with OFA and SCNR, and 3) LNB with OFA and SCR. The EPA believes that given a 20 year useful life, the LNB with OFA and SCR is cost-effective. However, if the useful life is less than 20 years, the cost-effectiveness of all three technologies will decrease because there is less pollution to remove. There should be two inflection points here. The first inflection point would be where the LNB with OFA and SCR is no longer cost-effective, and the LNB with OFA and SCNR would then be considered the best available technology. The second inflection point would be where the LNB with OFA and SCNR is no longer cost-effective, and the LNB with OFA then becomes the best available technology.

The inflection points move depending on what is considered the cost-effectiveness limit, and while CUB believes it is well below [redacted]/ton, the EPA has not established a bright line of what this should be. Nevertheless, enough decisions have been made by the EPA to give some guidance. PacifiCorp ought to be able to identify approximately where these inflection points are for the control technologies that are eligible for consideration for BART.

iii. PacifiCorp chose the wrong years for retirement dates.

[redacted] As CUB has pointed out, the [redacted]/ton figure is too high. Additionally, after establishing this high figure, PacifiCorp ignores it for the purpose of establishing an early retirement date for Bridger 3.

[redacted][29] [redacted][30] This makes little sense. [redacted] Part of the reason that this makes no sense is that inherent in an early closure is EPA's resetting of the compliance deadlines. In addition, while PacifiCorp is modeling these plants as closing in [redacted]

[29] LC 57 - 2013 Integrated Resource Plan, Confidential Volume III at pg 11.
[30] LC 57 - 2013 Integrated Resource Plan, Confidential Volume III at pg 11.

The EPA supported PGE's plan to phase out Boardman over 10 years (2010 to 2020), so it is known that the EPA can support a longer timeline.

iv. PacifiCorp's Study is flawed.

The combination of these two errors – assuming a [redacted]/ton cost-effectiveness threshold and closing the plants earlier than even required by the [redacted]/ton threshold – renders PacifiCorp's hypothetical analysis flawed to the point that it does not tell us whether early retirement should be considered.

v. PacifiCorp should do a better analysis.

PacifiCorp needs to redo this analysis and to do it correctly. The Company needs to establish a cost-effectiveness limit that is more realistic. CUB recommends a level of $3000/ton unless the Company has information that suggests that a higher level is being used by EPA to evaluate eligible technologies. This cost-effectiveness should be applied against the technologies that are being considered as BART and not against individual subsets of those technologies.

The goal should be to identify approximately where the inflection points are between the various technologies. Once these are identified, the Company should then see if it might lower its costs to close at that deadline. If the model shows an early closure date as lower cost, or if it seems reasonably close to being lower cost, PacifiCorp should enter discussions with the EPA to determine whether it is worth pursuing.

It is important to recognize that early closure is an option that will take agreement between the Company and the EPA. The purpose of the modeling should be to identify which plants could benefit from this treatment and to then enable pursuit of those opportunities. It is not critical that PacifiCorp establish perfect cost-effectiveness or that it identify exactly the right year for closure in its model, because the actual date of closure - and the pollution control

requirements associated with that date of closure - will be established through discussions with the EPA and other stakeholders. The key to this exercise is the identification of the right units to pursue. The ultimate question is whether there is a path going forward that EPA would support, that is at a lower cost to customers, and that can only be determined after discussions with EPA that help identify the costs associated with phasing out various units.

The potential cost-effectiveness of a phase-out is also why the Company should be considering in its analysis *all* units that face regional haze requirements as early in the process as possible. This is an alternative path that could potentially save customers money, but CUB recognizes that it may take some time to work out the details with EPA and other stakeholders. Waiting until the Company is facing a nearly immediate compliance deadline (such as with the plants reviewed in this IRP's coal study) to even begin to consider whether this is an option worth pursuing is the wrong approach because it does not leave enough time to pursue an alternative option if it is potentially worth undertaking. As stated previously, while it is helpful that the Company is at least accepting of the early closure approach as a theoretical possibility, it remains disappointing that the Company has once again failed to apply the theory in a reasonable way - in a way that could actually reduce costs to its customers.

E. CUB Recommends that the Hunter 1, Bridger 3, and Bridger 4 environmental compliance investments not be acknowledged.

PacifiCorp's analysis of the phase-out alternative is so flawed that it provides no value to the IRP. Without better analysis, it is not clear whether phasing out the plants would be cost-effective or not. Without better analysis concerning alternatives to the investments PacifiCorp is proposing to make, it is CUB's position that PacifiCorp is failing to meet its burden to prove that the proposed investments are the least-cost/least-risk possible. In short, CUB does not believe that there is sufficient evidence on which to base acknowledgment of these investments.

III. Transmission

CUB's primary concern with the IRP's discussion of transmission investments involves the System Benefits Tool (SBT).

Page 3 of the IRP states that the SBT is meant to quantify benefits that "are not captured using production cost dispatch models traditionally used for IRP analyses."[31] The Company discussed the derivation of these benefits in further detail during its workshop on February 27, 2013. From these two sources CUB understands that in order to identify the "Customer and Regulatory Benefits," the Company modeled a catastrophic failure that would knock out power to every customer on the eastern side of its territory. The problem with this modeling is that the Company assumed that such an outage would once in the next 20 years if the requested transmission investment was not made and that the system failure would not happen at all if the requested investment was made. For the Windstar to Populus segment, this assumption creates the Customer and Regulatory Benefits calculation of $249 million listed on page 11 of PacifiCorp's presentation.[32] The Company's treatment of the SBT is such that the probability of a catastrophic failure without the construction of the Windstar to Populus line equals 100%, while the investment in the transmission segment is equivalent to a 0% chance of failure because of the availability of a greater transmission resource. The jump from 0% to 100% is concerning to CUB, particularly because this reasoning is used to inform the $249 million figure, which is a significant portion of the net benefits. The Windstar to Populus calculation of benefits is also included in the IRP:

[31] LC 57 – 2013 Integrated Resource Plan, Volume I at pg 3.
[32] LC 57 - 2013 Integrated Resource Plan, Transmission System Benefits Tool Update, IRP Modeling and Results Update, Class 2 DSM Supply Curves Review (February 27, 2013).

Figure 1 – Windstar to Populus Benefits Calculation[33]

Benefits Calculation	Case EG2-C07
System Optimizer Analysis	$511
Avoided Transmission System Capital Cost	$151
System Reliability Benefits	$112
Improved Generation Dispatch	$39
Segment Loss Savings - Energy	$69
Segment Loss Savings - Capacity	$18
Customer and Regulatory Benefits	$249
Wheeling Revenue Opportunity	$16
Total Benefits ($m)	$1,165
Costs *($m)*	$ (934)
Net Benefit ($m, 2012$)	$ 231

As the figure shows, the $231 million net benefit would not be possible without the Customer and Regulatory Benefits value of $249 million. However, this value is based on an ambiguous assumption involving a 100% guarantee of avoiding a catastrophic failure. CUB is worried that because the Company is relying on benefits calculations derived outside of its usual IRP, the benefits potential of the proposed projects are being hastily overstated. It is CUB's opinion that the SBT should be subject to further scrutiny, as well as stakeholder input in future IRP sessions, before the tool can be relied on to accurately predict the benefits of a transmission project that costs nearly one billion dollars. Specifically, the Company needs to develop a better approach than the binary tool used here (build it – no outage; don't build it – outage affecting everyone), and the Company needs to be able to provide a much better explanation of why its assumptions are reasonable.

[33] LC 57 - 2013 Integrated Resource Plan, Volume I at pg 67.

IV. Conclusion

CUB responds to PacifiCorp's IRP with three main points. The first is that the Company should not have rejected a least-cost resource scenario due to uncertainties about DSM. PacifiCorp has already demonstrated that it can surpass its own DSM goals two years in a row. Because PacifiCorp pursues DSM more aggressively in Oregon and gets results, the Company should be considering more aggressive DSM modeling in other states as well. PacifiCorp is mandated to provide least-cost, least risk service to customers, the current DSM proposal will not provide least-cost/least-risk service to customers. CUB is, therefore, recommending that the Commission not acknowledge the DSM portion of PacifiCorp's current IRP.

CUB is also recommending that the Commission not acknowledge the Hunter 1, Bridger 3, and Bridger 4 environmental compliance investments. In CUB's opinion the Company still did not undertake a sufficiently rigorous analysis in considering the the phasing out of its coal units. Various aspects of the Company's study were deeply flawed, particularly its choice of the cost-effectiveness limit, its choice of closure dates, and its choice of clean air investment useful lives which were not consistent with the useful lives of the plants.

Finally, the assumption upon which PacifiCorp based its selection of a multi-million dollar transmission investment - that of avoiding a catastrophic system failure - did not provide a sound basis for the Windstar-to-Populus benefits calculation. The SBT should be subject to further review by other stakeholders in a public process so that the benefits can be examined in depth.

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Respectfully Submitted,
August 22, 2013

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LC-57/PacifiCorp
August 7, 2013
CUB Data Request 2

CUB Data Request 2

See page 5 of PacifiCorp's 2013 Integrated Resource Plan. The Company states, "Over the 2013 to 2022 timeframe, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent (prior to forecasted load reductions from energy efficiency).

(a) From where was the compounded annual rate of 1.2% growth in system peak load derived?
(b) What were the assumptions behind the calculation of the 1.2% figure?
(c) What was the historical timeframe used to forecast the 1.2% figure?
(d) Where does the Company derive its values for the forecasted load reductions from energy efficiency?

Response to CUB Data Request 2

(a) Please refer to Appendix A – Load Forecast Details in the 2013 Integrated Resource Plan (IRP) for the annual coincident peak load forecast in which the 1.2 percent was derived, specifically, Table A.2.

(b) The assumptions used in the coincident peak forecast are explained in Appendix A of the 2013 IRP.

(c) The historical time frame used in the Company's load forecast for the 2013 IRP was January 1997 through March 2012.

(d) Class 2 Demand Side Management (DSM) load reductions are included as resources in the System Optimizer Model. The Company derives its values for the forecasted load reductions based on the preferred portfolio selection of Class 2 DSM.

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(a) Please refer to Appendix A – Load Forecast Details in the 2013 Integrated Resource Plan (IRP) for the annual coincident peak load forecast in which the 1.2 percent was derived, specifically, Table A.2.

(b) The assumptions used in the coincident peak forecast are explained in Appendix A of the 2013 IRP.

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Consolidated Summary by State

Generation Site	Class 2							Class 1		
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	Total	Idaho	Utah	Total
2012	6,396,303	12,614,617	211,758,474	236,248,188	49,781,945	23,253,965	540,053,492	206.18	150.40	356.58
2011	6,939,322	9,660,007	200,532,716	265,652,099	49,983,693	14,857,833	547,625,670	286.82	180.95	467.76
2010	3,237,152	13,095,503	198,999,701	218,754,816	41,727,271	23,239,279	499,053,722	308.08	172.79	480.87
2009	2,733,512	16,362,890	124,478,000	247,798,817	57,383,355	8,060,609	456,817,183	285.20	155.95	441.15
2008	517,825	11,539,506	138,681,000	193,327,673	48,323,349	0	392,389,353	237.63	97.28	334.91
2007	209,778	12,061,271	109,651,217	148,969,408	38,415,375	0	309,307,049	85.07	101.22	186.29
2006	365,613	13,016,455	104,562,259	121,090,668	57,683,057	1,137,928	297,855,979	55.40	90.46	145.87
2005	117,103	8,780,643	113,289,921	113,004,054	28,692,164	0	263,883,885	56.01	47.50	103.52
2004	3,736,165	4,453,614	135,681,107	103,582,575	34,101,633	963,856	282,518,949	34.90	27.79	62.69
2003	118,892	3,284,657	62,043,719	72,705,567	32,627,468	0	170,780,302	25.08	11.45	36.54
2002	38,437	4,276,496	68,579,352	74,157,875	32,554,766	0	179,606,926	0.00	0.00	0.00
2001	85,775	3,000,163	148,789,691	16,746,331	11,690,182	284,248	180,596,390	0.00	0.00	0.00
2000	68,657	2,505,040	21,020,773	3,855,228	13,066,219	0	40,515,916	0.00	0.00	0.00
1999	178,519	976,893	19,402,848	78,090,570	7,208,616	9,528	105,866,973	0.00	0.00	0.00
1998	735,136	1,165,607	17,992,861	47,471,496	7,276,163	106,508	74,747,771	0.00	0.00	0.00
1997	949,884	1,597,223	36,020,633	105,440,953	6,408,419	10,082,777	160,499,890	0.00	0.00	0.00
1996	1,830,059	3,608,697	61,383,336	83,053,166	17,098,417	46,168,780	213,142,455	0.00	0.00	0.00
1995	3,672,680	875,644	168,386,385	89,794,799	31,670,580	1,903,113	296,303,201	0.00	0.00	0.00
1994	12,051,571	2,221,530	72,368,313	74,772,571	18,978,120	252,775	180,644,880	0.00	0.00	0.00
1993	4,295,607	3,551,145	91,682,051	10,820,918	20,977,982	127,412	131,455,115	0.00	0.00	0.00
1992	1,649,248	2,622,181	48,081,143	20,558,465	10,101,041	80,187	83,092,265	0.00	0.00	0.00
Total	49,927,236	131,269,781	2,153,385,501	2,325,896,237	615,749,814	130,528,797	5,406,757,367			

LC 57 – CERTIFICATE OF SERVICE

I hereby certify that, on this 22nd day of August, 2013, I served the foregoing **OPENING COMMENTS OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket LC 57 upon each party listed in the LC 57 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending one original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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