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August 27, 2015

VIA ELECTRONIC MAIL ONLY

Attention: Filing Center
Public Utility Commission of Oregon
2930 Fairview Industrial Drive SE
PO Box 1088
Salem, OR 97308-1088

Re: *In the Matter of PACIFICORP, dba PACIFIC POWER's 2015 Integrated Resource Plan*
OPUC Docket No.: LC 62
DOJ File No.: 330030-GN0339-14

Filing Center:

On behalf of the Oregon Department of Energy, enclosed for electronic filing today with the Commission in the above-captioned matter are OPENING COMMENTS OF THE OREGON DEPARTMENT OF ENERGY.

Sincerely,

Lore Bensel
for Renee M. France
Senior Assistant Attorney General
Natural Resources Section

RMF:jrs/#6755032

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 62

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER	)	OPENING COMMENTS OF THE
	)	OREGON DEPARTMENT OF ENERGY
2015 Integrated Resource Plan	)	
	)	
	)	

The Oregon Department of Energy (Department) appreciates the PacifiCorp's (Company) thorough stakeholder engagement process throughout the development of its 2015 Integrated Resource Plan (IRP), particularly its efforts to explain the underlying modeling processes used to complete it. The Department also appreciates the level of effort that the Company put into this IRP.

We recommend that the Commission acknowledge the action plan with the addition of a second Oregon demand response pilot and pilots related to aggressive implementation of energy efficiency. In addition, we ask that the final order direct the Company that future modeling should always assume existing state Regional Portfolio Standard law in its base case and that the Company vary its modeling approach including its assessment of the value of storage in the future. The Department is concerned that the existing modeling approach may undervalue aggressive energy efficiency and reduce the forecasted avoided cost used to set QF prices.

The Department's comments on the Company's IRP cover the following items:

1. Renewable Portfolio Standard compliance
2. Pilot programs for energy efficiency and demand response, and comprehensive analysis of demand response
3. Inclusion of 111d constraints in each stochastic modeling run
4. Inclusion of a reasonable approximation of the effects of the final 111d rule on western wholesale power prices

5. Comparisons of various portfolios using comparable assumptions on implementation of regional haze rules and other basic assumptions
6. Performing a full risk analysis on a more aggressive energy efficiency portfolio
7. Comprehensive analysis of the system benefits of energy storage

A. DEPARTMENT COMMENTS ON PACIFICORP'S 2015 IRP ACTION PLAN

The Department raises concerns with two portions of the Company's 2015 IRP Action Plan: Renewable Portfolio Standard compliance and treatment of risk in analysis of energy efficiency and demand response.

The Department recognizes the complexity faced by the Company in creating and filing its 2015 IRP while at the same time attempting to plan for and adapt to the U.S. Environmental Protection Agency's (EPA) Carbon Pollution Standards Under the Clean Air Act 111d Rule (hereinafter 111d). We offer comment on 111d modeling and carbon constraints with recognition of the difficulty the Company had in ensuring compliance with the final rule prior to its release. We also offer observations designed to ensure the Company is reasonably situated to comply with the final rule.

1. Action Item 1a: Renewable Portfolio Standard Compliance

The Department notes that the Company only modeled one scenario for compliance with 111d that treated renewable energy certificates (RECs) used in Oregon Renewable Portfolio Standard (RPS)[1] compliance as containing the zero-carbon (or "111(d)") attribute. In the base scenario, it appears that the Company assumes the environmental attributes may be used separately from the REC, which is not consistent with existing state requirements. We observe several complications with this approach. In the Western Renewable Energy Generation Information System (WREGIS), where the Company is required to manage its RECs, the zero-carbon attribute is a required component of the REC. By disaggregating the zero-carbon attribute

[1] Oregon Renewable Portfolio Standard, Or. Rev. Stat. § 469A; Or. Admin. R. 330-160.

from the REC, there will be two separate claims, which could occur in different states, for each megawatt-hour of electricity associated with a particular renewable facility. This could lead to a double claim for tracking purposes within WREGIS.

In addition, existing Oregon administrative rules defines RECs as containing all environmental attributes, including the zero-carbon component, and requires "whole" RECs for compliance with the state RPS. The RPS has thus become a central element of Oregon's strategy for reducing greenhouse gas emissions. If the zero-carbon attribute of RECs were allowed to be split off and retired separately (either physically or temporally) from its original REC, Oregon could no longer rely on its RPS policy for reducing and tracking CO2 emissions from its electricity mix.

For the next IRP, the Commission should instruct the Company that its base model should be compliant with existing state policy regarding environmental attributes of RECs. In addition, the Department recommends PacifiCorp restructure how it models 111(d) to include examination of mass-based compliance, as this is a viable option under the 111d. The Company should do this assessment alongside an assumption that whole RECs, retaining their environmental attributes, are retired for state RPS policy compliance.

2. Action Items 3a and 3b: Class 1 and 2 Demand Side Management Actions

The Department recommends that the Commission add action items for more pilot programs for accelerated energy efficiency (EE) in other states and an additional demand response pilot in Oregon. These additional pilots would not substantially change the amount of front office transactions (FOTs) in this plan, but may provide information that could substantially alter future IRP actions plans.

The Department finds that the Company has not adequately made the case that the energy efficiency or demand response programs in its proposed action plan adequately address risks, particularly carbon risk. As a result, the plan may rely too heavily on front-office transactions. As described below, the IRP relies almost entirely on a base-case wholesale price forecast to develop its action plan that the Department views as unrealistically optimistic. Because the base

case wholesale price forecast and the Company's anticipated compliance obligation under the draft 111d rule are biased downwards for the base-case (111d-only) scenario, it is likely there are inadequate levels of energy efficiency in the proposed four-year action plan. Full consideration of the risks of future carbon price regulation would also increase the appropriate levels of energy efficiency pilot programs.

The Department appreciates the company's efforts to implement a summer direct load control irrigation pilot in the Klamath Basin. We support this pilot as an effective way to determine both the cost and benefits of demand response for future IRPs. However, we would like to see the company implement an additional Oregon demand response pilot in either the west side or the Klamath basin that tests direct load control of a resource that is viable for both peak reduction and regulation in all seasons.

The Department would also like the Company and the Commission to ensure that in all emerging technology pilots, such as those for demand response and storage, priority is given to determining not just the peak shaving value of the resource, but also the full range of potential system benefits. The Department further discusses this preferred analysis methodology in our storage comments below.

B. DEPARTMENT COMMENTS ON PACIFICORP'S DEVELOPMENT OF ITS 2015 IRP ACTION PLAN

For all future integrated resource plans, the Department requests that the Commission:

1. Direct the Company to use a method to constrain each stochastic modeling run to roughly comply with the 111d final rule
2. Direct the Company to run the System Optimizer with a reasonable approximation for the effects of the final 111d rule on western wholesale power prices
3. Instruct the Company that comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions
4. Instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio

5. Require comprehensive analysis of the system benefits of storage

1. The Commission should direct the Company to use a method to constrain each stochastic modeling run to roughly comply with the 111d final rule

It was not possible for the Company to replicate the 111d rate-based structure in the stochastic analysis using its Planning and Risk (PaR) model. Nor did the Company use a carbon dioxide price as a proxy for 111d regulation. This means the present value of revenue requirements (PVRR) results of various PaR runs are not comparable. The Department requests that for the next IRP, the Commission direct the Company to go back to a carbon price as a proxy approach or use some other method that constrains each stochastic run to comply in a rough manner with the rule. The Company should not use the PaR results for planning without such an adjustment.

The risk approach used in this IRP was unworkable and likely will be more unworkable in the next IRP. This IRP risk analysis assumed all states adopted the rate-based approach. Still, the Planning and Risk (PaR) model was not able to constrain the stochastic runs to comply with the draft 111d rule. If a mix of mass-based and rate-based approaches is viable under the final rule, having the PaR model, or likely any stochastic model, ensure compliance with the details of the final 111d rule is even more unlikely. A proxy carbon price approach, based on alternative assumptions about implications of 111d compliance on the prices for ERCs under the rate-based approach, or carbon allowances under the mass based approach would likely be more workable.

The use of carbon price scenarios as a proxy for existing and potential federal carbon regulations would yield more robust and workable analyses to capture the possibility of major trading activity as the western states implement 111d, either under a rate-base or mass-based approach.

The Company should either develop a method that can meet 111d in each stochastic run or use a CO2 price proxy in every PaR run to adjust PVRR to correct for different CO2 emissions. Given the likelihood that at least some states will pursue a mass-based approach to compliance under 111d, modeling only a rate-based approach in the next IRP would be unsound.

By using a range of trading prices in the next IRP, the Company could provide a useful analysis that includes a reasonable range of 111d outcomes.

The Commission should direct the Company to ensure that it adopts a workable risk analysis in the next IRP.

2. Direct the Company to run the System Optimizer with a reasonable approximation for the effects of the final 111d rule on western wholesale power prices in this base case.

The IRP likely underestimated the challenges of meeting the 111d rule. It also likely underestimated expected values of future wholesale prices in the West. As noted above, PacifiCorp assumed that the draft 111d carbon regulations over the next 20 years would *reduce* wholesale prices in the base case as compared to the no carbon regulation case. The Department finds this outcome implausible. Even with this low base case power price forecast, the accelerated energy efficiency case (Portfolio C11) and the preferred portfolio (Portfolio C05) have virtually identical present value of revenue requirements (PVRR) in the SO model. The PaR stochastic model results that show higher expected PVRR for the accelerated energy efficiency are not persuasive because the PaR model does not constrain each run to comply with the draft 111d rule. Further, the optimal portfolios for higher carbon price scenarios (C14 and S11) show that if carbon regulation moves beyond 111d, or regional haze requirements become more stringent than the Company expects, it will need to quickly expand energy efficiency efforts. The accelerated energy efficiency case is a proxy for the PVRR costs of expanded pilot programs for energy efficiency to prepare the Company for these contingencies.

Options for an improved methodology include, but are not limited to, using a proxy carbon price approach to adjust the base-case wholesale price forecast from the IRP. Without such an adjustment, the wholesale price forecast is likely an underestimate of the expected value due to a failure to consider a range of carbon regulatory outcomes over the next 20 years. In this

IRP, the Company assumed that imposition of the draft 111d rule would *lower* western wholesale power prices.[2]

While the Company developed carbon price scenarios, it did not use these to guide its decision-making in developing the action plan.[3] Further, the base-case scenarios (C05) make the unrealistic assumption that all western states have energy efficiency programs that reduce loads 1.5 percent each year starting in 2020. This assumption has the effect of lowering wholesale power prices below the case with no carbon regulation.

Imposition of some type of incremental carbon regulation beyond 111d during the 20-year planning period is highly likely. Thus, the expected wholesale prices over the next 20 years will likely be higher than the base case 111d forecast, which in turn should be higher than the no-carbon-regulation case.

The result is that PacifiCorp's forecast of wholesale prices is biased downward for their base case modeling under core case C05a-3Q, which they use for planning. This bias tilts the action plan toward wholesale power purchases and away for demand-side resources such as energy efficiency and demand response.

In addition, given past practices of the Company and the Commission, it seems likely that this forecast will be used to forecast wholesale electricity prices for standard QF contracts after docket LC 62 concludes. The use of this price in standard QF contracts would undervalue QF

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[2] *See* Or. Dept. of Energy calculation "Data That Underlies 2015 PacifiCorp IRP Figure 7.7 on Vol. I Page 149" in Appendix I.

[3] PacifiCorp 2015 Integrated Resource Plan, 146 *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf; page 146. The IRP explains the medium scenario of CO_2 prices in the following way: "PacifiCorp has also developed core cases that include, incremental to EPA's proposed 111(d) rule, CO_2 price assumptions that were recommended by members of its stakeholder group. Consideration of these core cases recognize that there could be future CO_2 emission policies applicable to the electric sector that go beyond requirements proposed by EPA in its 111(d) rule. [i.e., the CPP] Figure 7.6 shows CO_2 price assumptions applied to these core cases during the 2015 IRP portfolio development process. Prices are applied to each ton of CO_2 emissions from new and existing resources … reaching $75.77/ton [nominal dollars] by 2034." Note, these are nominal prices. Consistent with OPUC's IRP guideline #8a cited above, the Company also modeled a high sensitivity case where the CO_2 price is approximately $160 per ton (nominal dollars) in 2034.The Company based this case on an agreement with stakeholders for a high CO_2 price case.

resources. It is currently unclear in UM 1610 which proceedings before the Commission will be the appropriate forum to assess the forecast of wholesale prices used for calculating avoided cost prices. Given that uncertainty, the Department includes this concern in this docket.

a. The Base Case 20-Year Wholesale Price Forecast is a Poor Representation of Likely Values

The IRP relies almost entirely on the base case wholesale price forecast to develop its action plan. While the plan correctly notes that there are not huge differences in the amount of energy efficiency for the first four years of the various core cases and sensitivity cases, there are differences. Because the base case wholesale price forecast and the Company's requirements under the draft 111d rule are biased downwards for the 111d-only scenario, it is likely there are inadequate levels of energy efficiency in the proposed four-year action plan. Full consideration of the risks of future carbon price regulations would also increase the appropriate levels of energy efficiency pilot programs.

The IRP notes:

> *Primary drivers in the resource differences between PacifiCorp's 2015 IRP and the 2013 IRP Update include decreased load forecasts and* ***lower power prices****.* [Emphasis added].[4]

The Company forecast of wholesale power prices (a mix of Mid-Columbia and Palo Verde wholesale prices) and Henry Hub (HH) natural gas prices (nominal dollars)[5] show a modeling anomaly. The difference between the prices used in base case modeling[6] and the case assuming no carbon regulations or pricing is calculated in the fourth column. In every year, the power price is *lower* in the 111d case than in the "No CO2 Case."[7] This is the opposite of the

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[4] PacifiCorp 2015 Integrated Resource Plan Volume I, 239.
[5] PacifiCorp 2015 Integrated Resource Plan Non-confidential Data Disk: Data for "Figure 7.7 – Wholesale Electricity and Natural Gas Prices in Core Case Definitions."
[6] The September 2014 Official Forward Price Curve or OFPC assuming a specific scenario of 111d implementation
[7] PacifiCorp 2015 Integrated Resource Plan Volume I, 149 Values for Figure 7.7.

expected effect. One would expect that adding a constraint such as the 111d rule would raise the equilibrium power price in the Aurora Power Price Model.

The IRP notes:

> *To account for 111(d) in Aurora, PacifiCorp applied state 111(d) emission rate constraints in the model, assuming energy efficiency goals assumed by EPA in its calculation of state emission rate targets is achievable.*[8]

This base case assumption forces each of the eleven states in the West to achieve large reductions in load from energy efficiency, relative to the "No CO2 Case." This assumption is likely the source of the lower power prices in the base case for the years 2021 and beyond. Lower power prices for 2015 through 2020 may be due to the use of forward wholesale prices as of September 2014 for the first 72 months in the official forward price curve as contrasted with the use of the Aurora model to forecast prices for the other two cases. Regardless, these results show that the IRP base case price forecast implies zero or even negative implicit carbon prices for the next 20 years. Note that, in the table, power prices are higher in every year for the case (C14) with an incremental carbon pricing in addition to the 111d rule. This is the normal outcome: carbon pricing or regulations should raise, not lower, power prices.

In addition to the assumption of high attainment of energy efficiency to estimate the base wholesale power prices, the Company in its IRP makes several other assumptions about how 111d will be implemented that make compliance more flexible than the Department anticipates the states will allow. The two effects reduce the need for energy efficiency in the base case runs (C05) for the Company to comply with 111d.

First, the Company assumes there will be no compliance obligation for the coal-fired power plants that the Company owns in Montana, Colorado and Arizona. The Department appreciates that modeling these costs in the IRP framework is difficult. Still, these costs are unlikely to be zero.

[8] PacifiCorp 2015 Integrated Resource Plan Volume I, 149.

Second, the Company assumes that it can use energy efficiency credits from Idaho and California to meet 111d compliance in other states. The Company assumed this transfer because it has no 111d plants in these two states. While that outcome might result in lower 111d compliance costs, it is not clear the two states will allocate their energy efficiency credits from their state's 111d compliance plans to the Company or that the credits will meet the requirements for use in Oregon or the other states.

Third, as enumerated above, the Company assumes that the carbon attribute of RECs can be redistributed for compliance at plants throughout the Company's service area to minimize its compliance costs.

b. Inclusion of Carbon Pricing

While the carbon prices or regulations that will be in effect over the next 20 years are not known, the Department expects that carbon pricing or regulations will go beyond the Company's base case assumptions for 111d. The Company and IRP participants spent a considerable amount of time coming to a consensus on a medium and a high scenario for proxy prices for carbon dioxide regulation. The Department acknowledges that it is possible that there will be no effective carbon pricing or regulations imposed on the Company over the next 20 years. However, using a wholesale price assumption with a zero or negative carbon price assumption as the sole driver to develop an IRP action plan is not consistent with Commission Order No. 08-339. Guideline 8a of that Order states, in part:

> *The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2)... [and] develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities.*[9]

The IRP has a base case power price forecast below the bottom of the range CO2 proxy prices ranging from zero (C01) to the high price sensitivity case (S11). In addition, a zero carbon price

[9] Oregon Public Utility Commission Order No. 08-339, C1 *available at* http://apps.puc.state.or.us/orders/2008ords/08-339.pdf

is not the "present CO_2 regulatory level." State plan implementation of the final 111d rule will almost certainly put upward pressure on wholesale power prices. While it is conceivable that the final implementation of the 111d rule will yield power prices below a case with no CO2 regulations or pricing, that outcome is unlikely. A dominant method of meeting 111d will likely be redispatch from coal to natural gas-fired plants. Doing so can only increase wholesale prices above a no-regulation case. Regional haze rules have also tended to increase in stringency over time. This effect, too, will increase wholesale prices above the level in the base case forecast.

Generally, if there are restrictions on the operation of coal-fired power plants, limits on carbon dioxide emissions or taxes or other pricing of carbon dioxide emissions, these interventions constrain the operations of the western power grid from what would otherwise minimize costs and power prices. Except in rare cases, outside constraints tend to increase wholesale power prices. While it is likely that more energy efficiency would tend to lower power prices, it seems unlikely that 111d will increase EE enough to counteract the cost increases for redispatch to gas plant or other elements of the rule that increase power system costs. While the total benefits of the 111d rule may outweigh the increase in power system costs, the rule is unlikely to lower power system costs outright. Regardless of future carbon regulation under 111d and other measures, the base case forecast has lower power prices than the most extreme carbon regulatory future possible: the U.S. reverting to no carbon constraints or pricing at all.

Even with the underestimated base case wholesale prices, the SO PVRR results with for C11-1 (the accelerated energy efficiency case) and C05-1 (similar to the preferred portfolio) under Regional Haze scenario 1 (RH1) are virtually identical. Similarly for C11-2 and C05-2 (both under RH2) (plus $2 million and minus $2 million PVRR for C11, respectively). In both RH scenarios under the SO model the C11 portfolios had slightly superior CO2 emissions over 20 years.

The Company correctly notes that PaR results are not constrained to meet 111d. The Company implicitly acknowledges the PaR results should not be used for planning. The SO

results indicate that higher short-term EE acquisitions have lower risk than the proposed action plan with the same expected costs, even with the underestimated base case wholesale prices.

These results indicate accelerated EE might be superior on the basis of least-cost adjusted for risk. The Company should test pilots that accelerate EE programs. The Company should use information from these pilots to guide the next IRP.

3. The Commission should instruct the Company that comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions

The comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions.

a. Many of the Results Compare PVRR Results for Variants of C05-3 with Portfolios that Comply with the More Stringent RH Scenarios 1 and 2. This is a Misleading Comparison.

Scenario CO5-1 is the only scenario that can legitimately be compared to other RH 1 scenarios. Similarly, only CO5-2 can legitimately be compared to portfolios under the RH 2 scenario. No portfolio, other than C05, was tested under RH3. Because the compliance costs under scenario RH3 are less than for RH1 and RH2, the comparison of the PVRR of C05-3 variants with other portfolios is misleading. A prime example is the comparison, below, of C05a-3 and C05b-3 with C13-1 on pages 182-183 of Vol I of the IRP. This is not a fair comparison of deterministic risk among these three portfolios.

The Department also has concerns about how the Company used the four regional haze scenarios to evaluate the present value of revenue requirements (PVRR) under the SO and PaR models. Many of the results compare PVRR results for regional haze scenario 3 for the base portfolio (C05-3) with other portfolios that comply with the more stringent RH scenarios 1 and 2 (see Table 8.23 – Cost/Risk Comparison of Portfolios that Meet Oregon House Bill 3543 Emission Goals with the Preferred Portfolio).[10] This is a misleading comparison. The

[10] PacifiCorp 2015 Integrated Resource Plan Volume I, 210.

Commission should instruct the Company that comparisons of various portfolios should use comparable assumptions.

b. Inappropriate Comparisons using Different Regional Haze Scenarios

In the Company's 2015 IRP, portfolios are generated by assuming a scenario in the SO model. There are 14 core portfolios and 15 sensitivity portfolios in the IRP and each portfolio has up to three regional haze variants. The Company generated the portfolios labeled C05 under base-case assumptions with no carbon pricing beyond the specific 111d assumptions. There are three types of typically used C05 portfolios, one for each regional haze (RH) assumption (RH Scenarios 1, 2 and 3).[11]

Comparisons of the cost and carbon emission of various portfolios are not comparable if the RH scenarios are different. Yet, the IRP routinely compares the base portfolio (C05) under RH Scenario 3 with other portfolios that meet the more stringent requirements of RH Scenarios 1 and 2. Portfolio CO5-1 can legitimately be compared only to other regional haze one (RH 1) scenarios. Similarly, only CO5-2 can legitimately be compared to portfolios under the RH 2 scenario. The Company tested no portfolio, other than C05 and S-10 under RH3. Because the compliance costs under scenario RH3 are less than for RH1 and RH2, the comparison of the PVRR of C05-3 variants with other portfolios is misleading. The cost differences in these RH stringencies can be seen in the comparisons of the SO model results for portfolios C05 a-1, a-2 and a-3.[12]

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[11] *Note*: There is also a Reference Regional Haze Scenario, but the Company used it to construct one portfolio and did not further utilize it. Each RH scenario generates a different level of costs for the Company for reducing emissions of sulfur and oxides of nitrogen. Each scenario also differs in the stringency in the reduction of carbon emissions. Of the three RH scenarios that received the most scrutiny, RH Scenario 3 is the least stringent, RH Scenario 1 is more stringent, and RH Scenario 2 is the most stringent. The one minor exception to this pattern is Dave Johnson Unit 4 (DJ4), a relatively small unit. Scenario RH3 shuts down DJ4 five years earlier than in Scenarios RH 1 and 2. This exception does not alter the stringency rankings of RH Scenarios 1, 2 and 3.

[12] The SO-PVRR for these portfolios are (in billions of nominal dollars) $26.591, $27.240 and $26.578, respectively. The SO modeled carbon dioxide emissions are (in million tons over 20 years) 879.8, 832.6 and 906.5, respectively. The stochastic mean PVRR results for the PaR model with the medium natural gas price scenario are $27.718, $28.517 and $27.570. The carbon emissions in the PaR runs have a similar pattern to the SO runs. Thus, while not equivalent, RH1 is closer to RH3 than is RH2. *Note*: "a" refers to a timing of later acquisition of bundled renewable energy certificates for Oregon RPS compliance.

Yet, even though there is a substantial cost saving with the RH3 scenario, the IRP makes various comparisons in which the RH scenarios are inconsistent.[13] These comparisons are not fair in either the deterministic or the stochastic assessments among these portfolios. The Commission should instruct the Company that it only make comparisons where the basic assumptions are comparable.

4. The Commission should instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio.

The Department is concerned that Scenario C11 (accelerated EE) was not properly analyzed. The Commission should add an Action Plan item that enhances the Company's ability to accelerate EE through pilot programs. These programs would likely have small PVRR costs.[14]

The Company correctly dismisses PaR results as not compelling regarding portfolio selection,[15] yet the Company did not further analyze C13 with RH3 (C13 is mass based compliance on existing plants).[16]

The SO PVRR results for C11-1 and C05-1 are nearly identical; similarly for C11-2 and C05-2 with no carbon adder beyond EPA 111d rule. In both cases, the C11 portfolios had slightly superior CO2 emissions over 20 years in all gas price scenarios. These results indicate accelerated EE might be superior based on least-cost adjusted for risk. The Commission should add an action item that requires the Company to test pilots that accelerate EE programs. The Company should use this information to guide the next IRP.

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[13] Similarly, Fig. 8.18 on page 188 compares these same portfolios. See also Table 8.23[13] on page 210 where the preferred portfolio with RH3 (C05a-3Q) is compared with C13-1 with RH1 and C13-2 with RH2.

[14] For RH scenarios 1 and 2, the SO results for C11 are virtually identical to CO5 (plus $2 million and minus $2 million PVRR).

[15] Note that C13-1 is superior to C05-1 in PaR for all three NG price scenario (risk-adjusted PVRR difference ranges from $266 to $272 million).

[16] Company response to Oregon Dept. of Energy Data Request 4. For full response, see Appendix II.

5. The Commission should require comprehensive analysis of the system benefits of storage

The Department requests that the Company conduct a comprehensive analysis of energy storage as one of several strategies available to utilities and transmission system operators to integrate variable energy resources (VER) by providing a means to firm the output of the renewables. In addition, the Company should analyze electrical energy storage as a strategy to reduce transmission congestion, defer investments in the distribution grid, add flexibility and resiliency to the electric system, and increase the reliability and quality of power delivered to customers. Since its 2011 IRP, the Company has included energy storage in resource planning, resulting in completion of engineering studies and evaluation of the potential for only a limited application of energy storage technologies.[17]

Although project costs are high on a dollars-per-kWh basis, the technology is changing rapidly and there are specific applications where utility-scale storage has a strong business case today. In the Department's comments on the 2013 PacifiCorp IRP,[18] we asked that future IRPs offer a more comprehensive treatment of energy storage. Storage is a unique resource that does not fit neatly into existing categorizations because it is not strictly generation, demand-side management, or energy efficiency. We further requested that, "PacifiCorp should be prepared to report in future IRPs on energy storage advances and opportunities to incorporate storage technologies into its portfolio as a flexibility and reliability tool." We repeat that request in this IRP.

a. Analysis of Storage as a Resource Option

The company covers energy storage in the 2015 IRP under Chapter 6 - Resource Options. The goal of the Company analysis is to identify least-cost, least-risk resources to meet future energy and capacity needs. In this context, the Company evaluated energy storage against

[17] PacifiCorp 2014 Smart Grid Report *available at* http://edocs.puc.state.or.us/efdocs/HAQ/um1667haq163543.pdf; PacifiCorp 2015 Smart Grid Report *available at* http://edocs.puc.state.or.us/efdocs/HAQ/um1667haq93558.pdf

[18] Final Comments of Oregon Dept. of Energy in PacifiCorp 2103 Integrated Resource Plan,11-13 *available at* http://edocs.puc.state.or.us/efdocs/HAC/lc57hac84953.pdf

generation resources such as gas combustion turbines. This type of analysis discounts the many potential system benefits of energy storage that are not strictly contributions to energy and/or capacity. This analytical approach is apparent in Tables 6.1 and 6.2, where energy storage is included with all other **supply-side** resources and characterized by capital cost, fixed cost, operating characteristics and environmental characteristics.

The Energy Storage section of the 2015 IRP[19] describes only a few use-cases for energy storage, specifically time-shifting of energy production from VER, delivery of ancillary services, and voltage control. The narrative of this section of the IRP focuses almost entirely on the capital cost and life-cycle costs, which the Company then compares to the other supply-side resources and finds to be financially unattractive to provide the same services. This approach to evaluating energy storage as a supply-side resource leaves out many use-cases that may be cost saving to the Company and improve its operations.

b. Analysis of Storage as a Smart Grid Technology

In contrast to the 2015 IRP, the Company evaluated energy storage in its 2014 and 2015 Smart Grid Reports as a means to defer transmission and distribution asset investments at specific substations. This is again only one use-case that an energy storage system is capable of delivering. The conclusion in both reports that energy storage is not an economic alternative is due in part to its narrow analysis.

The Company should incorporate value stacking into the analytical approach toward evaluating the potential system benefits of energy storage. Value stacking is a method that acknowledges the possibility of achieving multiple use-cases from a single resource and adding up the electric system values of all the use-cases. Research conducted at Sandia National Laboratories resulted in the 2014 NAATBaat report,[20] which describes 16 different use-cases, identified by electric utilities around the country, which energy storage can provide to the

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[19] Storage analysis begins on page 116 of Company's 2015 IRP.

[20] NAATBatt Distributed Energy Roadmap Report, Sandia National Laboratories PO #1367842 (Feb. 17, 2014) *available at* http://naatbatt.org/wp-content/uploads/2015/06/NaatBatt_Report_FINAL_021814.pdf

electric system. The Company should enhance its analytical approach to incorporate all the relevant types of use-cases to evaluate energy storage systems.

Collaborative research at Pacific Northwest National Laboratories (PNNL) and pilots conducted at other northwest investor-owned utilities that are part of the Northwest Power Pool clearly show the benefits of using a single energy storage system for multiple applications. PNNL has supported utilities by providing a framework for evaluating the technical and financial benefits of battery energy storage.[21] The tool developed at PNNL is used to evaluate benefits of battery storage for multiple grid applications, including energy arbitrage, balancing service, capacity value, distribution system equipment deferral, and outage mitigation. This tool is based on the optimal control strategies to capture multiple services from a single energy storage device. Limiting an energy storage system to a single use-case will most likely underestimate the benefits of that investment, while choosing a practical number of use-cases that most needed and optimizing the control of the energy storage system to deliver those services can be cost-effective.

c. Pilot Projects and Compliance with HB 2193

Oregon House Bill 2193,[22] which passed after the Company finished modeling 2015 IRP, requires the Company to procure an energy storage system of at least 5MWh by January 1, 2020.[23] The Company should focus on gaining practical experience and verifying use-case benefits in its territory in its compliance with the legislation.

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[21] Assessment of Energy Storage Alternatives in the Puget Sound Energy System Volume 2: Energy Storage Evaluation *Tool available at* http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23039.pdf

[22] H.B. 2193, 78th Leg. (Or. 2015) *available at* *https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193/Enrolled*

[23] Oregon H. B. 2193 (2015) provides possible criteria to examine the potential value of applying energy storage system technology, including: (A) Deferred investment in generation, transmission or distribution of electricity; (B) Reduced need for additional generation of electricity during times of peak demand; (C) Improved integration of different types of renewable resources; (D) Reduced greenhouse gas emissions; (E) Improved reliability of electrical transmission or distribution systems; (F) Reduced portfolio variable power costs; or (G) Any other value reasonably related to the application of energy storage system technology.

The Department welcomes the opportunity to collaborate with the Company and facilitate access to tools, resources, and lessons learned from energy storage research and pilot programs conducted in both the Northwest and other parts of the country. In the upcoming PUC process to implement HB 2193 and in future IRPs, we request a more comprehensive approach to energy storage system analysis that incorporates a variety of use-cases that meet the Company's electric system needs.

C. CONCLUSION

In summary, the Department requests changes to the Company's model in the future in order to ensure that it assigns proper value to resources such as energy efficiency and QFs. We request that the Commission direct the Company to implement a demand response pilot on the west side of Oregon and pilots for aggressive energy efficiency, and that the Company models the comprehensive benefits of demand response and storage in future IRPs.

Thank you for the opportunity to provide comment.

DATED this 27th day of August, 2015.

Respectfully submitted,

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