PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

November 5, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: LC 62 PacifiCorp's Final Comments

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing its Final Comments on PacifiCorp's 2014 Integrated Resource Plan.

Please direct any informal inquiries to Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 62

In The Matter of PACIFICORP dba PACIFIC POWER 2015 Integrated Resource Plan.	PACIFICORP'S FINAL WRITTEN COMMENTS

I. INTRODUCTION

In accordance with the procedural schedule adopted by the administrative law judge in this proceeding, PacifiCorp d/b/a Pacific Power (Pacific Power or the Company) respectfully submits these final written comments. PacifiCorp filed its 2015 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on March 31, 2015. Parties filed comments and acknowledgment recommendations on August 27, 2015. The Company submitted reply comments on September 24, 2015, and the following parties submitted final written comments on October 15, 2015: Commission Staff (Staff), Renewable Northwest (RNW), the Oregon Department of Energy (ODOE), the Industrial Customers of Northwest Utilities (ICNU), the Renewable Energy Coalition (RC), and the Sierra Club (SC). There were two parties who filed opening comments, but not final comments: the Citizens' Utility Board of Oregon (CUB) and the Northwest Energy Coalition (NWEC).

II. EXECUTIVE SUMMARY AND RECOMMENDATIONS

PacifiCorp's final written comments address specific recommendations and suggestions outlined in the parties' final comments. The Company does not generally restate its position on topics that were addressed in its reply comments, although reiteration is necessary in some instances. Finally, PacifiCorp notes that Staff and parties have recommended modifications or additions to certain action items, and in some cases, recommend new action items for inclusion in the Company's 2015 IRP Action Plan. The Company expresses its position on these recommendations in its final comments. If the Commission chooses to accept the parties' recommended modifications or additions to the Company's 2015 IRP Action Plan, PacifiCorp respectfully requests that it do so through a clarification or exception in its order rather than requiring the Company to file a modified action plan.

Highlights of the Company's final comments include:

- The Wallula to McNary transmission line is the least cost option available for the Company to meet its mandatory obligation to its transmission customer. The project also provides a number of reliability and other benefits to PacifiCorp's transmission system and customers. As described in Chapter 4 of the IRP, Chapter Highlights, PacifiCorp is requesting acknowledgement of its plan to construct the Wallula to McNary portion of the line "based on customer need and associated regulatory requirements." PacifiCorp's Action Item on this investment is aligned with Oregon's IRP Guidelines.

- Additional Class 1 and Class 2 demand side management (DSM) pilot programs requested by Staff and stakeholders are unnecessary. These programs were not shown to be cost effective, and will provide little additional information. The Company will continue to evaluate suggestions in the 2017 IRP for potential new programs.

- As recommended by Staff, PacifiCorp will continue to provide twice yearly updates on the status of DSM IRP acquisition goals in 2016 and 2017.

- The Company cautions parties against being too prescriptive in any modeling approach to the Clean Power Plan (CPP). State-based compliance plans are currently under development. The 2015 IRP Update and future IRPs will incorporate new information as it becomes available and the Company is committed to continue to work with stakeholders in the public input process to inform future analysis.

- Other suggestions for modeling changes, presentation of information, and study additions are discussed below. The Company believes the majority of these issues are best addressed through the 2017 IRP public input process, and not through new requirements.

The Company's IRP was prepared consistent with Order No. 14-252, in which the Commission acknowledged the Company's 2013 IRP, with exceptions and revisions to the Action Plan; Order No. 14-296, covering the specific fleet analyses to be performed in the 2015

IRP; and Order Nos. 07-002 and 07-047, in which the Commission adopted the Oregon IRP Guidelines. In determining whether to acknowledge an IRP, the Commission considers the extent to which the plan satisfies the procedural and substantive requirements of Oregon's IRP Guidelines and whether the plan is reasonable at the time of acknowledgement. PacifiCorp respectfully requests that the Commission acknowledge its 2015 IRP and the 2015 IRP Action Plan.

III. REPLY TO PARTIES' FINAL COMMENTS

A. Transmission

1. Energy Gateway permitting

a. Parties' Recommendations

Staff recommends acknowledgement of Action Item 5a which consists of a variety of activities for segments of Energy Gateway. Staff recognizes the uncertainty in developing these segments with in-service dates anticipated for 2019 and later. Table 4 of Staff's comments contains a modified Action Item as compared to the one proposed by the Company. The revised version reads as follows:

> Action Item 5a: "Continue permitting Segments D, E, F, and H until PacifiCorp files its 2017 IRP."

b. PacifiCorp's Comments

The Company appreciates Staff's support in acknowledging Action Item 5a. The original language in the IRP provides more detailed information than Staff's revised version. As such, the Company recommends including the original Action Item, and not the revised Action Item.

2. Wallula to McNary 230 kilovolt transmission line

a. Parties' Recommendations

Staff recommends acknowledgement of Action Item 5b, completion of the Wallula to McNary project with an in-service date of 2017. Staff maintains that the project is not justified on an economic basis. However, it is the least-cost option available to meet the Company's federal requirements under its Open Access Transmission Tariff (OATT). Staff recommends adoption of the Action Item with the following language:

> Action Item 5(b): "Complete Wallula to McNary project construction per plan, with 2017 expected in-service date, as required for regulatory compliance with PacifiCorp's FERC-approved OATT."

b. PacifiCorp's Comments

The Company believes that Action Item 5b with Staff's proposed amendment is reasonable. As Staff notes, this action is necessary to comply with federal regulatory requirements.

3. Other Transmission Issues

a. Parties' Recommendations

In Staff's summary of NWEC's comments, Staff highlights NWEC's desire for "transmission assessment reconsidered within the IRP process." Staff also cites NWEC's statement that closure of coal plants that will "free up transmission capacity." Staff suggests the Company examine resource development in geographical areas where there is freed-up transmission. Staff also recommends updating the dynamic transfer capability between east and west balancing authority areas (BAA). Staff also suggests that PacifiCorp should update its analysis to, "reflect the potential benefits of the formation of an RTO between PacifiCorp and the California ISO."

Other parties raised issues with transmission availability in the winter to meet west-side peak needs. ICNU and REC both discuss the potential for a new west-side resource due to inadequate transmission capacity flowing from east to west.

b. PacifiCorp's Comments

The Company's reply comments, filed September 24, 2015, addressed NWEC's comments on the Company's Energy Gateway (EG) strategy. The Company will assess EG alternatives in its resource plan to support any prospective transmission build out scenario that is part of the Company's least cost/least risk plan.

Regarding Staff's concern with "freed-up transmission," the Company did analyze resource placement with the potential implications of unit retirements. The inputs associated with transmission rights owned by the Company and contracted with third parties remain unchanged regardless of the timing of unit retirements. For example, the transmission path that allows generation from the Dave Johnston plant to be delivered to load centers outside the Wyoming area can continue to be utilized after the plant is assumed to retire at the end of 2027. The Company's IRP analysis allows for replacement resources at that location to take advantage of available transmission and lower costs associated with brown field resources. For example, the Preferred Portfolio added new combine cycle combustion turbines at the Dave Johnston location after the coal-fired Dave Johnston plant is assumed to retire at end of 2027.

The Company will update the transfer capability between East and West BAAs going forward. As noted in PacifiCorp's response to OPUC data request 75, at the time the IRP inputs were locked down for modeling purposes, the change in transmission rights were not certain. As such, the change was not modeled.

A clarification on NWEC and Staff's discussion of an RTO is needed. The Company is exploring the formation of a regional ISO, which is not identical to an RTO. Also note, the formation of a regional ISO is not certain at this point. The 2015 IRP Update and future IRPs will assess the ongoing evolution of regional ISO discussions, and incorporate additional information and analysis as appropriate.

PacifiCorp addressed many of the transmission availability questions raised by ICNU and REC[1] in its initial reply comments filed on September 24, 2015. In response to Staff's request to study the impact of meeting a targeted planning reserve margin for the winter system coincident peaks, it is clear that the Company has sufficient resources to meet its winter peak requirement, which includes transmission availability. The Company is open to discussing the issue with Staff and other interested stakeholders during the 2017 IRP public input process.

B. DSM – DR Pilots

1. Parties' Comments

Both Staff and ODOE suggest the Company should consider developing additional pilot programs for DSM. Staff lists four pilot programs for which it would like to see proposals:

1. A residential direct load control pilot (water heaters, AC, Thermostats, etc.);
2. An aggregator-led commercial DR pilot;
3. An industrial load control pilot that operates to address peak load reduction and not restricted in use to emergencies and enhanced reliability; and
4. An innovative time of use rate pilot proposal that does not need to leverage AMI infrastructure to result in benefits to the customer and the utility.

[1] REC sates "The NW Energy Coalition also raised this concern." on page five of their final comments. The Company did not find mention of transmission availability, or winter peak needs in NWEC's opening comments. It is not clear what NWEC concerns REC is referencing.

ODOE continues to request a pilot program for Class 1 DSM on the west-side of Oregon or in the Klamath basin that is available in all seasons. While recognizing such a program would not be cost effective, ODOE believes a pilot of this nature could be informative. ODOE also reiterates its support for the Commission to mandate additional pilot Class 2 DSM programs outside of Oregon.

Staff also argues that Class 3 resources such as time-of-use (TOU) pricing should be available as a potential least-cost resource option in the IRP. ODOE agreed with the Company that TOU rates are best addressed through rate design. ODOE, however, states that marketing and implementation of TOU rates may be a resource planning issue and requested "the Commission ask the Company to engage Oregon stakeholders in an informal process to address increased voluntary participation in TOU and present the outcome of this informal process to the Portfolio Options Committee."

2. PacifiCorp's Comments

While the Company understands Staff's interest in furthering demand response efforts in the state, the Company does not share the belief that piloting new programs is always a necessary first step. Unlike the irrigation load management pilot proposed in the 2015 IRP Action Plan, the Company believes there is less uncertainty around the costs and effectiveness of the three load management pilots proposed by Staff (residential direct load control of water heaters, air conditioners and thermostats, aggregator-led commercial demand response and industrial load control addressing peak load reductions). When needed, the Company is confident that market-ready versions of these programs can be implemented with predictable results, saving the company and its customers the costs of pilot efforts.

As to ODOE's Class 1 DSM proposal, the Company's reply comments addressed this issue, stating the product that best fits the "all season" criteria would be a commercial/industrial sector curtailment product due to the diversity of end-use loads available for management. The vendors offering these types of products have proven track records of launching full-scale deployments of their products within twelve to eighteen months. These pay-for-performance models are not new and currently manage thousands of megawatts of commercial, institutional and industrial loads for utilities each year. Of all the possible load management products on the market, these types of business curtailment programs are the easiest to get up and running, are some of the most reliable programs, and have control technologies and strategies designed to seamlessly integrate with customers' existing energy management systems and operational practices.

The Company contracts for third-party assessments of the potential opportunities of commercially available Class 1 DSM products every two years as part of its DSM resource potential study updates. If the search for products as part of the 2017 update identifies an "all season" product that would be a good candidate for a pilot program, then the Company would engage parties in Oregon to determine if support exists for piloting the program.

The Company addressed ODOE's proposal for additional Class 2 DSM pilots outside of Oregon in reply comments filed September 24, 2015. In short, the Company plans to pursue the cost-effective acquisition of Class 2 DSM resources identified in Company's 2015 DSM potential study and selected by the 2015 IRP for inclusion in the IRP Action Plan. Selected, technologies are incorporated through addition to existing energy efficiency programs or through the development of specific programs designed to acquire the selected resources. Speculative or unproven pilot programs may be developed to test the market acceptance prior to full-scale program deployment. However, test of market acceptance of any programs must be technology and/or measure specific and pilot programs, in most cases, are not necessary.

The Company will continue to adaptively manage its DSM programs through its current processes and adopt emerging opportunities as appropriate to ensure their pursuit either by adding them to existing programs, introducing a new program or through a pilot program.

As the Company explained in its reply comments, Class 3 DSM programs including TOU are appropriately considered in rate design where specific rates and customer impacts can be considered. Unlike Class 1 DSM, Class 3 programs rely upon customer behavior and do not provide firm reductions to peak load and cannot be relied upon for planning purposes.

The Company has been conducting a pilot for irrigation TOU over the last two summers and is currently evaluating participants' experiences. Based on this evaluation and feedback, the Company expects to bring a proposal for continuation, expansion, or modifications to the Commission early next year.

The Company currently provides a TOU pricing option for customers under Schedule 210, and is interested in re-evaluating the current TOU rates for other classes and exploring other potential rate structures. There are concerns with establishing on- and off-peak price differentials that balance program participation with cost causation to minimize any cost shifting to other customers.[2] To achieve a high level of participation, a TOU rate must be sufficiently attractive so customers will participate and change their behavior. Providing generous bill savings with a TOU rate to participating customers may result in cost shifts to non-participating customers, which should be considered in determining cost effectiveness of Class 3 DSM programs. Again, these issues are best addressed outside of the IRP process.

[2] On- and off-peak differentials in Schedule 210 prices range from four to ten cents per kWh, and can be higher than actual Mid-Columbia differentials. In calendar 2014 for example the heavy load hour and light load hour market price differentials were 0.7 and 1.4 cents/kWh for winter and summer respectively.

The Company recognizes that there may be opportunities for alternative optional pricing programs that are based upon costs and provide an incentive to encourage participants to change their behavior in ways that minimize cost for the Company's system to the benefit of all customers. Consideration of these opportunities should take into account the timing of the need for new resources, timing of potential deployment of new metering technology by the Company, flexibility to adapt or incorporate market changes that may influence prices, and cost recovery.

C. Reserve Issues—Thirteen Planning Reserve Margin

1. Parties' Comments

Staff believes the planning reserve margin (PRM) study demonstrates a lower PRM (11 percent or 12 percent) is lower cost and meets the Company's required level of reliability. Going forward Staff would like more studies that test the upper and lower bounds of PRM so corresponding costs may be compared. Further, Staff clarified its earlier comments to address confusion expressed by the Company.

ICNU reiterates its opening comments, stating that the PRM study is flawed in that it looks at the loss of load probability (LOLP) in all hours of the year, as opposed to strictly examining the LOLP in the peak hour of the year. ICNU also states a summer resource acquisition to meet summer peak needs may provide little additional capacity in other hours of the year. These two facts may overstate the actual need, resulting in selection of a summer peaking resource that does not contribute materially to capacity needs in the west during a winter peak.

2. PacifiCorp's Comments

As Staff pointed out, the Company's report (Appendix I – Planning Reserve Margin Study) notes all PRM under evaluation meet the "one day in ten year planning" criterion.

However, that criterion is only one of the reliability measures. Other measures provide different perspectives on portfolio reliability using different PRMs. As listed in the report, Expected Unserved Energy (EUE) measures the magnitude of loss of load events, and Loss of Load Events (LOLE) measures the frequency of loss of load events. When comparing the 10 and 13 percent PRMs, the 13 percent PRM reduces both the magnitude and frequency of loss of load events by approximately 50 percent. A PRM of 11 percent has limited reduction in these measures, comparatively. A PRM of 12 percent may reduce loss of load events but with approximately same amount of increases in costs as a PRM of 13 percent when compared with PRM of 10 percent.[3] In short, when considering all factors, use of a 13 percent PRM was deemed preferable.

In addition, a reasonable PRM should ensure sufficient resources to meet the other requirements beyond the peak load, such as contingency reserves, regulating margins, reduction in resources due to forced outages and unexpected increases in peak load. The amount of contingency reserves required is three percent of load and three percent of operating generation, which equates to approximately six percent of load. The expected forced outage rates for new combined cycle combustion turbines are over two percent, as listed in Table 6.1 in the Company's 2015 IRP report, and the older thermal resources may have higher expected forced outage rates. Appendix H to the Company's 2015 IRP report studies the amount of regulating margin needed to deal with variation in wind and load. That is, of the 13 percent PRM, approximately eight percent has been committed to serve known obligations beyond peak load, and the remaining five percent would be needed to cover other planning uncertainties such as load and resource availability. As indicated in its reply comments, the Company is willing to

[3] Table I.3 of Appendix I of Volume II to the Company's 2015 IRP report compares the reliability metrics by RPM. Table I.4 compares the costs of by RPM.

work with Staff and stakeholders in the 2017 IRP public process to address any perceived shortcomings.

The Company addressed ICNU's comments in its reply comments filed on September 24, 2015. The response simply is that the determination of a resource portfolio is based on the load obligation at the time of the system peak, and the study of loss of load events in all hours is to determine whether such a resource portfolio would be sufficient to maintain reliability of the system *during a period of time* at a reasonable cost. In the PRM study, the Company did not attempt to add resources for the summer time (FOTs) to meet the winter need, which is demonstrated by Table I.1 in Appendix I to the Company's 2015 IRP report.

D. Modeling

1. Clean Power Plan and 111(d) Modeling

a. Parties' Comments

Several parties, including Staff, ODOE, RNW, and REC again raise issues with the modeling of 111(d) compliance in the Company's 2015 IRP. In general, parties focus on two issues. The first is the use of renewable generation for both a renewable energy credit (REC) and a 111(d) attribute. The second issue is the Company's use of an emissions rate compliance target rather than a mass based compliance target.

b. PacifiCorp's Comments

In reply comments, the Company noted a lack of clarity regarding the interaction of 111(d) and state RPS requirements. However, the Company's assumptions were reasonable at the time they were made (i.e., before EPA's final rule was published). The Company will update its modeling consistent with assumptions based on the recently released final CPP rule. Again, in the 2015 IRP Update and future IRPs, the Company will look at the ongoing evolution of requirements under the CPP, as well as incorporate information as states begin to develop their CPP implementation plans. Separately, the Company has committed to working with state agencies while they are developing state plans to implement the CPP to work through many of these complexities.

2. Forward Price Curves

a. Parties' Comments

In summarizing NWEC's opening comments, Staff states it agrees that the official forward price curve (OFPC) is outdated and "falls short of reflecting many of the long-term drivers of natural gas prices." Staff believes the OFPC does not incorporate many long-term drivers of natural gas prices. ODOE expects to see higher wholesale market prices under a mass-based compliance approach to the CPP. ODOE also takes issue with the gas forecasts and suggests having a high forecast that at least matches what was seen in 2008.

b. PacifiCorp's Comments

The Company addressed NWEC's complaints in reply comments filed September 24, 2015. In the reply comments, the Company pointed out that NWEC had misinterpreted Figure 7.15, which showed gas price volatility around a "base" gas forecast. In the stochastic analysis, in the high gas price scenario, the underlying west side natural gas price is \$7.84/MMBtu in 2024. Applying short term volatility leads to a 99th percentile price of \$8.21/MMBtu in 2024.

The Company also disputes the contention that the forecast is dated and does not incorporate long-term drivers of gas prices. While a September 2014 forecast may be dated today, it was appropriate for use in preparing the 2015 IRP as it was the most current available when modeling began. The OFPC is made of forward market prices in the near term (front 72 months) and a WECC-wide fundamentals based forecast for the long-term (months 85 forward) and a blend of the two (months 73-84) for the intervening time. The gas forecast used in the long-term, fundamentals portion comes from independent third-party forecasts. These fundamentals forecasts would, by definition, incorporate the "missing" long-term drivers of gas price forecasts cited by NWEC and Staff. For further discussion on the OFPC process, refer to page 148 of the Company's 2015 IRP. In addition, as stated previously, the 2015 IRP Update and future IRPs will look at the ongoing evolution of requirements under the CPP as well as incorporate information as states begin to develop their CPP implementation plans.

Regarding ODOE's suggestion of a forecast that at least has a peak matching the upper bounds seen in 2008, the Company is not clear on how to implement such a forecast, and whether such a view of the future is valid given the current market conditions. As stated above, for long-term forecasts the Company relies on third-party forecasters. These forecasts do not incorporate the high values that ODOE would like to see. Stochastic analysis incorporates volatility around said forecasts, but again the analysis does not foresee such price swings. For future IRPs the Company will consider running sensitivities on gas forecasts as proposed via the Feedback Form similar to those done for solar cost in the 2015 IRP.

3. Resource Costs

a. Parties' Comments

Staff agrees with opening comments submitted by NWEC wherein solar costs were "too dated and thus too high." Staff believes this could be a challenge going forward as well with solar costs changing more quickly than a "slow moving IRP process." Staff suggests the use of sensitivity studies around solar costs in future IRPs.

b. PacifiCorp's Comments

Similar to the response to issues with so-called dated gas price forecasts, the solar cost assumptions used were appropriate when incorporated. Further, PacifiCorp provided a declining cost estimate for solar PV resources, based on stakeholder feedback, which is unique within the IRP, to capture the current trajectory. However, PV panel prices have declined to the point that they make up less than 40 percent of the price of a new resource. Any further declines in the price of PV panels will have less of an impact to overall solar project costs than they had in the past. In addition, PacifiCorp's research determined that there were several factors that could put upward pressure on the cost of new solar resources in the United States, including financial stress of some solar panel manufacturers, economic uncertainty in China and import tariffs on Chinese panels being imported into the United States.

Additionally, PacifiCorp made use of a stakeholder feedback form in the 2015 IRP, which allowed stakeholders to submit alternative solar costs. The Company studied these costs in sensitivity case S-12. For future IRPs the Company will continue to consider all relevant information on current and projected costs as well as proposed cost trajectories submitted by stakeholders.

4. *Storage*

a. *Parties' Comments*

ODOE and SC both reiterate their positions on storage as presented in their respective opening comments. Both ODOE and SC prefer to see more detailed modeling around storage in the Company's IRP. Such modeling is expected to capture all potential benefits associated with storage. Staff believes storage will become more cost effective and should be included in portfolio analysis.

SC does not believe current modeling approaches will allow selection of "an energy storage resource as an alternative to conventional generation..." It also faults the Company for only committing to install the amount of battery storage as required by law. Final comments from SC offer a recommend approach to energy storage modeling.

b. PacifiCorp's Comments

In its response comments, the Company stated that it will continue to improve its modeling approach for energy storage systems. This includes developing models to quantify a broadening range of benefits from specific applications of storage systems. Costs and operating characteristics of storage, as with all resources, will be updated in upcoming IRPs. The Company will continue to improve upon its modeling approach for energy storage systems and focus on incorporating multiple value streams where possible.

Clarification is required on SC's assumption that energy storage is "an alternative to conventional generation." Energy storage alone is not an alternative to conventional generation. Energy storage requires other generation sources to charge it before it can provide generation services. Therefore, it may be argued that the cost of energy storage should be added to the cost of other generation facilities.

As discussed in reply comments, the Company continues to look for potential sites where battery storage may be beneficial, i.e. encompassing multiple value streams. The most promising applications identified so far defer capital upgrades at substations. The value added from other use cases at those sites is small and those projects are not economically viable in the current operating environment. Currently the Company is in the process of obtaining a battery storage evaluation tool from Pacific Northwest National Laboratory for evaluating all storage options.

SC is incorrect in suggesting that "the company will only commit to the minimum 5MWh project required by law for 2020." PacifiCorp has committed to supporting Oregon State

University on a battery storage project under an Oregon DOE grant application. PacifiCorp is evaluating options for storage projects under the Washington Clean Energy Fund 2, and is exploring a consortium with Electric Power Research Institute in support of possible battery storage projects. In addition, the Company is evaluating battery storage as an alternative to traditional transmission and distribution system upgrades at various locations throughout its system. These efforts, as well as any additional project(s) proposed in response to Oregon HB 2193, will be used to demonstrate the economics of deploying battery storage on a larger scale within the Company's operating environment.

Storage has, and will continue to be, included in portfolio analysis. The 2015 IRP included storage as a supply-side resource option as shown in Table 6.1 and Table 6.2. There were several different types of storage including pumped hydro, compressed air energy storage (CAES), flywheels, and three types of batteries, lithium-ion, sodium-sulfur, and vanadium redox. There were also sensitivities that incorporated storage. Sensitivity S-06 forced a west side 400 MW pumped storage plant in 2024, while S-13 forced an east-side 300 MW CAES plant in 2024. The Company looks forward to a robust discussion of energy storage throughout the 2017 IRP public input process.

5. Resource sufficiency demarcation

a. Parties' Comments

RC continues to advocate for an earlier demarcation of resource sufficiency for thermal resources. That is, RC assumes the need for a new resource may be accelerated as compared to the year 2028 modeled in the Company's IRP. Several factors could accelerate this date, including different environmental requirements, lack of DR acquisition, changes in wholesale prices, liquidity of wholesale markets, and inadequate transmission. RC recommends the

Commission not acknowledge the year 2028 as the sufficiency date "because it is outside the action plan period..."

b. PacifiCorp's Comments

The Company agrees with RC that changes in many variables could change the timing of a new thermal resource. While RC focuses on items that could move that date forward, many others, such as lower load growth, increased numbers of qualifying facilities (QFs), could push the date out. In fact, the 2013 IRP envisioned a new thermal resource being necessary in 2024, while the 2015 IRP envisions a new thermal resource in 2028. This extension of the sufficiency period is driven in part by lower load forecasts and additional QFs.

RC does not offer a proposed date for demarcation between sufficient and deficient. It appears that RC would want a date inside the Action Plan timeframe. This is contrary to all Commission precedence, and in essence means a utility would never have more than a four-year sufficiency period. RC provides no support for its recommendation. As such, the Commission should not adopt RC's recommendation.

6. System Optimizer Modeling

a. Parties' Comments

SC continues to find fault with the Company's modeling of coal unit retirements believing that allowing SO to incorporate endogenous retirements would result in a more optimal modeling outcome. SC also asserts that the Company's comparison ignored the fact that SC's modeling included $730 million (NPV, 2015$)[4] in investments needed to be in compliance with Wyoming regional haze requirements, and if those investments are removed, its solution would be less expensive than the Company's Preferred Portfolio.

b. PacifiCorp's Comments

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[4] Page 13 of Sierra Club's final comments.

PacifiCorp's initial reply comments go into great detail on issues with modeling endogenous retirement, and PacifiCorp will not repeat its concerns regarding SC's modeling approach. The Company, however, notes that the adjustment or workaround that SC stated over-simplified the issues related to treatment of costs that are shared by multiple units and/or multiple plants. Without prescient knowledge when the early retirement or conversion might occur, it is difficult to establish how the timing for major overhauls should change and how this might influence costs. Moreover, endogenous modeling of early coal unit retirements as a compliance alternative to known or assumed emission control obligations is not compatible with analyzing inter-temporal and fleet trade-off compliance alternatives that might be available under the regional haze rule. Over the last two IRP cycles, stakeholders and the Commission have clearly communicated their desire that the Company consider inter-temporal and fleet trade-off alternatives when evaluating regional haze compliance obligations.

Finally, SC seems to suggest that their lowest cost case (Case A) was $42 million higher than the Company's Preferred Portfolio after including $730 million investment to comply with the Regional Haze federal implementation plan in Wyoming. It is not clear to the Company what the additional $730 million represents, given that the Company's Preferred Portfolio included all the necessary investments for regional haze compliance in the state of Wyoming. In addition, the description and discussion in Synapse's report suggest that Case A has not included recovery of stranded investment. The inclusion of such costs would lead to their portfolio being $540 million more costly than the Company's Preferred Portfolio.[5]

[5] Page 14 of the report by Synapse Energy Economics, Inc. attached to Sierra Club's initial comments lists describes the differences in Cases A, B and C. See discussion beginning on page 9 of the report regarding the treatment of stranded costs and decommissioning costs.

7. Avoided Costs in Parallel Filing

a. Parties' Comments

Staff cites opening comments from RC where it recommends a parallel process for filing avoided costs along with the IRP. In reply comments Staff states this is a suggestion that "merits further investigation."

b. PacifiCorp's Comments

The Company does not believe a parallel process for avoided costs is worth pursuing. This issue was also raised in OPUC Docket No. UM 1610 by ODOE. Staff did not believe a concurrent process was necessary, stating:

> Staff disagrees that a process that runs concurrently with review of an IRP is appropriate.[6]

This issue, as raised by RC should not be decided in this docket specific to PacifiCorp, but rather in the general docket open to all parties.

E. Guidelines

1. Guidelines

a. Parties' Comments

Staff commented on Guidelines 1: Substantive element, 5: Transmission, 6: Conservation and 12: Distributed Generation. In general, Staff notes the guidelines were met, but lists potential areas of concern going forward, or where potential improvements could be made. For Guideline 1 for instance Staff wants the Company to "continue to analyze all reasonable options for compliance with environmental regulations..." For Guideline 2 Staff would like PacifiCorp to update transmission modeling, including impacts of joining a regional ISO as clarified above. Conservation is covered by Guideline 6 where Staff discusses modeling as well as potential pilot

[6] See Docket No. UM 1610, Staff Brief at 9 (Oct. 13, 2015).

programs. Staff continues to advocate for a Preferred Portfolio with the accelerated DSM case for the 2015 IRP Update. Finally Staff raises questions with the potential study provided for distributed generation, which is included under Guideline 12.

ODOE raises issues with environmental compliance stating the 2015 IRP "most likely does not meet Guideline 8a." ODOE would like to see more scenarios assessed to address risk and uncertainty. Overall, it was not clear to ODOE how cases with differing CO_2 regimes impacted the 2015 IRP.

b. PacifiCorp's Comments

The Company has addressed most of the issues raised by Staff already. The Company will continue to update modeling consistent with environmental guidelines. Likewise, transmission assumptions will be updated, and information relative to participation in a regional ISO will be presented when available.

The Company already discussed issues with additional DSM pilot programs. Also, as stated in PacifiCorp's reply comments, the Company believes the base and accelerated DSM cases to be similar enough that there will not be much additional information gleaned from inclusion of an accelerated DSM run. The accelerated case was shown in the IRP to be less cost effective than the base case and inclusion of additional runs to re-prove this are not needed.

The Company is unsure what additional benefits from distributed generation (DG) energy resources are not included in the 2015 IRP as suggested by Staff. The DG as modeled was selected from a customer perspective, i.e. where it would be an economical choice. Further, the reductions to load were captured as there were hourly shapes for the different DG resources. As such this should capture avoided energy and capacity resources, as well as any deferred transmission benefits. However, the IRP does not look at the system on a distribution level.

ODOE's contention that the IRP does not satisfy Guideline 8a is off base. The Company did model several different compliance futures, and a variety of compliance scenarios as required by the guideline. Moreover, the Company developed these scenarios with stakeholder involvement, including active participation from ODOE, to specifically address Guideline 8a. The portfolios developed under these varied conditions are indicative of what would be preferred (or at least a starting point) under different assumptions. See also Table 9.3 where the Company discusses different resource acquisition paths based on different trigger events. Here there is qualitative discussion on potential changes in timing and selection of resources as policies (including CO_2) change. As stated in its opening comments, and contrary to ODOE's claims, the Company maintains that it has performed this IRP consistent with Oregon IRP Guideline 8a.

G. Other Recommended Action Items

1. Staff's Additional Recommendations

Staff recommends that the Company's Action Plan be acknowledged with some adjustments. Staff also includes a series of recommendations Commission requirements for the Company going forward. These recommendations are essentially a summary of information included earlier in Staff's final comments.

2. PacifiCorp's Comments on Staff's Additional Recommendations

PacifiCorp has provided comments above on Staff's recommendations and will not reiterate those comments here. In general, the Company does not support additional requirements beyond acknowledgement of the 2015 IRP. Many of the items, such as updates to transmission and sensitivity studies, should be considered normal business practice. Recommendations for modeling changes, or data presentation would be part of the 2017 IRP process, and should be discussed with stakeholders in the public input meetings. The Company has already noted its objection to additional pilot programs.

The Company recognizes that twice-yearly updates to DSM acquisition are valuable to the Staff and Commission. As recommended by Staff, PacifiCorp will provide twice yearly updates on the status of DSM IRP acquisition goals in 2016 and 2017.

IV. CONCLUSION

PacifiCorp's 2015 IRP complies with the Commission's standards and guidelines. The 2015 IRP also reflects a balanced consideration of customer interests and is well supported by portfolio modeling and prudent planning assumptions leading to selection of a least cost preferred portfolio and includes an Action Plan that is consistent with the long-run public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp requests that the Commission acknowledge the 2015 IRP and the 2015 IRP Action Plan, with the clarification to Action Item 5b, pertaining to the Wallula to McNary 230 kilovolt transmission line as suggested by Staff:

> Complete Wallula to McNary project construction per plan, with 2017 expected in-service date, as required for regulatory compliance with PacifiCorp's FERC-approved OATT. Continue to support the permitting process for Walla Walla to McNary

DATED: November 5, 2015

Dustin T. Till
Senior Counsel
PacifiCorp d/b/a Pacific Power

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's Final Comments with the Public Utility Commission of Oregon Filing Center, who will serve the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 5th of November, 2015

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