BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 62

In the Matter of PACIFICORP, dba PACIFIC POWER's 2015 Integrated Resource Plan.	Staff's Final Comments

Staff of the Public Utility Commission of Oregon (Staff) presents its Final Comments on PacifiCorp's (PacifiCorp or Company) 2015 Integrated Resource Plan (IRP or Plan). The Final Comments are separated by subject area and will be presented as follows:

I. Staff Replies to Party Opening Comments
II. PacifiCorp's Adherence to Oregon Commission IRP Guidelines
III. PacifiCorp's Compliance with Order No. 14-252 (Docket No. LC57)
IV. Action Plan Discussion
V. Conclusion and Summary of Recommendations

I. Staff Replies to Party Opening Comments

Northwest Energy Coalition (NWEC)
NWEC notes a concern that the twenty-year projection of resources has a notable lack of renewables in the future.[1] Staff notes that this trend, or lack of a trend, does exist in the Company's preferred portfolio. However, the resource buildout is driven solely by cost and is a result of the planning assumptions which include a relatively lax future regulatory landscape. The fact that no renewables are built out in the Plan is a result of straightforward economic analysis and reflects the need for strong policies for driving renewable development. If it is felt among stakeholders that more renewables are needed, the results of this IRP underscore the importance of policy decisions in realizing that need. The output of the IRP modeling shows that without additional regulatory requirements to drive renewables, future buildout may not be justified by pure economics.

NWEC is also concerned that the solar costs used in the analysis are too dated and thus too high. Staff shares this concern, not only in this IRP, but as a general issue – integrating the fast changing cost of solar within the relatively slow moving IRP process is challenging. It is difficult to utilize contemporary pricing throughout a process that can take up to two years to complete. The Company has attempted to address this issue by retaining well-respected contracting firms to develop renewable costs, but these attempts still capture costs that become quickly outdated.

[1] NWEC opening comments p 4

This will continue to be an issue as long as solar costs maintain their recent volatility. Staff suggests approaching this issue through sensitivity studies, varying the future cost projections for solar around its mean value and determining the sensitivity of the result to these changes.

NWEC also points out that the Company's official forward price curve does not include many other long-term drivers of natural gas prices such as well declining rates, gas market demand structure and future carbon price and regulation among other factors. NWEC believes that the current mid-period high gas price forecast of $6.50/MMBtu is too optimistic and that a high case of $8.00 or more may be warranted to accommodate all the upward price risks.[2] The IRP indicates that PacifiCorp's official forward price curve (OFPC) incorporates potential impacts of EPA's proposed 111(d) rule. Staff agrees with NWEC that the OFPC is outdated (September 2014) and falls short of reflecting many of the long-term drivers of natural gas prices.

Finally, NWEC would like to see transmission assessment reconsidered within the IRP process. Staff agrees. As large existing coal facilities are closed down over time their closure will free up transmission capacity. The Company needs to examine potential resource development in geographical areas that can access this freed-up transmission. The Company's planning should assess the benefits and costs of locating replacement renewable resources at these locations when the system becomes deficient in generation capability.

Oregon Department of Energy (ODOE)
ODOE recommends the addition of a second demand response (DR) pilot and pilot programs for acquiring aggressive levels of energy efficiency (EE). Staff agrees that additional focus on DR is warranted, particularly for addressing winter capacity needs, and requests further exploration of DR opportunities in addition to the irrigation pilot. ODOE also recommends that the base case in all future IRPs always include state Renewable Portfolio Standard (RPS) requirements and that the Company include in its analysis an assessment of the value of storage. Staff agrees. It is Staff's opinion that storage in various sizes, forms and uses will be increasingly cost-effective in the coming years and will need to be included in portfolio analysis.

ODOE also recommends that:

1. The Commission direct the Company to be sure that all cost risk analysis ("PaR" analysis) include the constraints needed for 111(d) compliance;
2. The Company needs to approximate the effects of 111(d) compliance on western wholesale power prices;
3. Portfolio comparisons should use the same Regional Haze assumptions; and
4. The Commission direct the Company to perform more risk analysis on portfolios including aggressive EE as a resource.

[2] Northwest Energy Coalition Opening Comments, pp 5-6

Staff agrees that implementation of these four recommendations would allow for more relevant comparisons between portfolios and provide a clearer economic picture for each portfolio.

Industrial Customers of Northwest Utilities (ICNU)

Winter Peak

ICNU is concerned that PacifiCorp has not adequately modeled the winter peak issue in its west "balancing authority" (BA). ICNU notes that a failure to properly plan for the western BA winter peak may lead the Company to choose non-cost-effective solutions for meeting that peak load. According to ICNU, the Company may choose to terminate cost-effective capacity contracts that currently help meet the winter peak, and this fact may influence the prudence determination of future resource acquisition. Staff agrees that this is an issue that demands more focus in the next IRP.

In its response to Staff discovery on this issue, the Company provided a "portfolio optimized to meet the Company's winter coincident peaks…"[3] which included the additional acquisition of a 101 MW "single cycle combustion turbine" (SCCT) peaking plant in 2019 as well as additional "front office transactions" (FOTs). This result appears to support ICNU's concern that certain capacity contracts should not be terminated – they may be more cost effective than building an SCCT or otherwise providing for the winter peak.

Staff would like to see more detailed analysis and several mitigation options from the Company if indeed there is a need for more winter capacity.

Reserve Margin

ICNU notes that changes in FERC regulations – specifically the move in system balancing rules from the "CPS2" standard to a new standard, the Balancing Authority Ace Limit (BAAL) – should result in lower reserve margins for affected utilities. However, the Company's wind integration study was structured on the CPS2 standard and so may not reflect savings resulting from a lower reserve margin expected from BAAL implementation.[4]

Staff believes this is a valid concern and one which should be vetted as the next wind integration study is undertaken. In general, Staff believes that a more accurate and precise view of the reserve margins necessary for reliable system performance is possible by analyzing all of the following reserve needs in a comprehensive fashion, rather than summing the reserves from a series of independent analyses. Staff encourages the Company to explore ways to analyze the Company's reserve needs in a more comprehensive manner.

In a related point, ICNU notes that, due to both implementation of the new balancing standard and the Company's participation in the Energy Imbalance Market (EIM), the expectation is that the "planning reserve margin" (PRM) should decrease. This is not the

[3] Company response to OPUC Data Request No. 4

[4] ICNU Opening Comments Docket LC 62, pp. 6-11

case in this IRP; the Company maintains a 13 percent planning reserve margin as it has for the last few IRPs. As noted in its Opening Comments, Staff recognizes the analysis and background work provided by the Company in calculating reliability metrics for a family of planning reserve margins.[5] From this study it appears that a lower PRM (11 percent or 12 percent) would meet the Company's required levels for reliability at lower cost, but for reasons not well explained, the Company chose to stay with a 13 percent margin. Staff expects a better quantitative explanation for the Company's choice of PRM in the next IRP. If there are a number of PRM levels that could provide adequate reliability performance, Staff expects the Company to provide sensitivity studies that explore the upper and lower bounds of PRM choice so that the corresponding costs can be compared. Staff believes that this issue is even more relevant now that PacifiCorp is seriously considering joining the California Independent System Operator (CAISO) to form a regional transmission organization (RTO). This was not represented in the Company's IRP analysis.

Renewable Energy Coalition (REC)

Capacity Deficiency

REC questions the demarcation date that represents the time when the Company first experiences a load-resource balance deficiency and requires additional generation capacity. Staff believes REC raises a valid concern regarding this demarcation period in the IRP. As REC notes, the Company's plan calls for the purchase of several hundred megawatts of capacity over a ten-year period. Staff agrees that this fact raises the question – does this purchase of short-term capacity constitute a *de facto* capacity deficiency? Typically, ratepayers benefit from a company's short position since meeting load with short-term purchases can reflect a lower ratebase earning a return. At the same time, though, Qualifying Facilities (QF's) and other independent power producers (IPPs) who could benefit by supplying capacity through contracts lose the opportunity to sell.

Although Staff understands the concern raised by the IPPs, Staff is compelled to apply the least-cost, least-risk principle in evaluating this issue. If the Company's plan of meeting capacity needs through market purchase results in lower rates for customers without incurring unacceptable risk, Staff would have a difficult time supporting an alternative plan with earlier deficiency period and higher costs to ratepayers.

REC also suggests parallel filing of avoided cost dockets along with the IRP. Staff has not had the opportunity to fully explore the impacts of such a filing schedule, but because the IRP informs the avoided cost process in several ways, Staff recognizes that parallel filing paths may create some procedural efficiencies. Staff believes this is a subject that merits further investigation.

Renewable Northwest (RNW)

RNW would like to see the Company include more extensive modeling around clean air regulations. RNW recommends that the Commission direct the Company to explore

[5] Vol II, Appendix I

compliance in ways that faithfully incorporate state law but also provides sufficient optionality so the state's ability to exceed the minimum standards is not limited.

Specifically, RNW states that the Company should explore more mass-based solutions and include early retirement scenarios for coal plants as 111(d) alternative compliance options.

Staff is supportive of RNW's recommendations and believes they will be helpful in identifying the least-cost, least-risk paths to regulatory compliance.

Sierra Club
Sierra Club raises several areas of concern that Staff and other parties have also noted. Of primary concern is the limited (rate-based only) approach to Clean Power Plan compliance used in the modeling. Also of concern is the Company's limited use of storage in its portfolio analysis, and of the accuracy of cost figures used in the storage analysis. Staff expects the Company to address both of these issues in detail in forthcoming IRPs as storage issues become prominent in the IRP process.

Sierra Club also includes a report from Synapse on its analysis of PacifiCorp's "System Optimizer" software modeling. The claim in the Synapse report is that the Company had erred in creating complex constraints in the model, including restrictions on endogenous[6] coal plant retirements. As shown in Table 3 (p.15) of the report, however, PacifiCorp's preferred portfolio provides a lower-cost alternative than any of the Synapse cases.

Staff notes that it is incumbent upon the Company only to demonstrate that the Plan adheres to least-cost, least-risk principles, follows the Commission guidelines, and that, taken in its entirety, it represents a reasonable resource plan.[7] In Staff's opinion, the results of Synapse's study do not challenge, and in fact support, acknowledgement of PacifiCorp's proposed action plan as a reasonable and least-cost plan.

PacifiCorp (PAC)
<u>Front Office Transactions – depth of market</u>
In its Reply Comments, the Company addressed Staff's concern regarding FOTs and concluded that it has "provided both qualitative and quantitative analyses to support its FOT limit assumptions in the 2015 IRP."[8] PacifiCorp also stated that it addressed REC's comments when addressing Staff's Opening comments and added that "PacifiCorp contends its market analysis is robust and reasonable, given the facts presented in Chapter 6 of the 2015 IRP, Appendix J to the report, confidential data responses, and further corroborating analysis by industry groups."[9]

[6] In this use "endogenous" refers to the capability of the software to determine plant retirements on its own without human intervention in the decision beyond that of input assumptions.
[7] OPUC Order 10-457, p.1 "Acknowledgement…means that the plan seems reasonable at the time of Commission review.", and Id. p.2, "Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement."
[8] See page 5 of PacifiCorp Reply Comments.
[9] PacifiCorp Reply Comments, LC62, p.44 at 18-20

In Chapter 6 of its Plan, the Company describes the nature of the FOT topic[10] but does not provide the quantitative support of how the Company arrived at the maximum levels of FOT put forth in Table 6.15 of its IRP below:

Table 6.15 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

The Company's only paragraph attempting to justify the limits in the table reads as follows:

"PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply (see Volume J for an assessment of western resource adequacy)."[11]

In Appendix J of PacifiCorp 2015 IRP, the Company describes the western resource adequacy evaluation, but does not address how the Company arrived at the maximum levels of FOT put forth in Table 6.15 of the Company's IRP. Finally, as part of its initial discovery Staff specifically requested that the Company quantitatively justify the stated maximum available FOT amounts.[12] In its response the Company described some of the characteristics that differentiate FOT limits among the different market hubs,[13] and represented the following:

> "*PacifiCorp is an active participant in each of the Front Office Transaction (FOT) markets assumed for the Integrated Resource Plan (IRP). By actively participating in the market, front office personnel charged with managing PacifiCorp's energy and capacity position gain insights on liquidity and the amount of power that is available for purchase for various forward time periods at given price levels.* ***These front office personnel, based on their institutional knowledge of each market, identify FOT limits at levels in which there is high confidence that power can be purchased at the assumed volumes and***

[10] See pages 128 and 129 of Chapter 6 of Volume I of the PacifiCorp 2015 IRP.
[11] See page 129 of Chapter 6 of Volume I of the PacifiCorp 2015 IRP.
[12] See responses to Staff DR 11, Staff Opening Comments, Attachment B, pp.8-9
[13] See the four bullet points provided in the Company response to Staff DR 11, which was included as pages 8 and 9 of Attachment B of Staff Opening Comments.

***at the assumed price** [emphasis added] tied to PacifiCorp's forward price curve (FPC).*"[14]

Staff's continued discovery and further requests for quantitative support for the stated FOT limits resulted in the Company's response:

> *"There is no further analysis beyond what the Company has responded in its response to OPUC Data Request 11."*[15]

Since a quantitative justification for the FOT limits has not been forthcoming from the Company, Staff can only conclude that such a justification simply does not exist.

Staff does not doubt the professional institutional knowledge of PacifiCorp's front office personnel. However, Staff believes that the FOT limit assumptions should be supported quantitatively to provide Staff, intervenors, and ratepayers with assurances that the Company is diligent in its assumptions. The lack of such quantitative assurance does not present a significant red flag in the 2015 IRP because the Company is not proposing to build a major new generating resource in the next two years that potentially could be covered with FOT transactions. However, Staff believes that a quantitative rationale for this assumption should be included in PacifiCorp's next IRP.

Staff recommends that, for the next IRP, the Commission require PacifiCorp to expand and refine its quantitative justification of the FOT limits assumed in its IRP.

<u>Reserve Studies</u>

The Company states confusion over Staff's Opening Comments regarding the choice of planning reserve margin.[16] To clarify, Staff notes that the Company has provided tables showing results of studies that offer several options for PRM that seem to meet the Company's reliability criteria. The Company states that "all PRM levels meet a one day in ten year planning criteria" and the least-cost solution is shown as a PRM of 10 percent.[17] Yet, in its conclusion to this section, the Company chooses a PRM of 13 percent with no qualitative rationale for that choice.[18] The Company's IRP narrative concludes that a PRM of 13 percent is the best choice but does not offer any further quantitative or cost analysis to justify this conclusion. Staff appreciates the Company's stated willingness to address this issue and expects further exploration of this subject in forthcoming IRPs.

<u>Wallula to McNary Transmission Line</u>

Staff maintains its position that, based solely its on economic benefits, building this transmission line is not well-justified. However, the overriding consideration in this action item is compliance with FERC requirements. Based on discussions with the Company, and as presented in the Company's Reply Comments, Staff is convinced that

[14] See page 9 of Attachment B of Staff Opening Comments.
[15] Company response to Staff DR 90 in LC 62
[16] PacifiCorp reply comments, p.9
[17] PacifiCorp 2015 IRP, Vol. II (appendices), see Table L4 on p.141
[18] Id. p.43

the project as proposed in the IRP is the least-cost approach for the Company to comply with its federal obligation (see confidential response to Staff DR 58). In this light Staff recommends adoption of the Company's amended Action Item 5(b) with the following amendment:

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 ".

Staff stresses that the "action" that the Commission is acknowledging is "regulatory compliance" and not the completion of the project on its own merits.

<u>DSM - Time of Use (TOU) Rates</u>

Staff disagrees with PacifiCorp's assertion that the discussion of time-of-use (TOU) tariffs does not belong in the IRP process.[19] Rather, through the IRP, PacifiCorp can determine in its list of least cost-least risk resources that deployment of TOU tariffs, as well as other smart grid programs like "demand response" (DR) or distributed energy resources (DER), can delay or negate the need for more costly, supply-side resources. Successful implementation and execution of TOU tariffs, such as standard TOU or variable peak pricing, with or without incentive components like "critical peak pricing" (CPP) can produce reliable peak demand reductions, load shifts that flatten load, or both depending on the types of programs deployed.

Utilities across the country are proving that TOU programs have the potential to serve as demand-side capacity alternatives. For example, Sacramento Municipal Utility District found that the percent demand reduction for opt-in TOU customers was 12 percent per customer; with a CPP component the average percentage demand reduction per customer was 25 percent.[20] Additionally, the benefit-cost ratios for the straight TOU pricing and TOU with CPP were 1.19 and 2.05 respectively. TOU programs will only become more available as capacity and energy resource alternatives as they are further refined and implemented. The IRP process can provide a role for these programs as more cost-effective alternatives to traditional supply-side resources.

PacifiCorp does attempt to quantify combinations of TOU and CPP for various customer groupings in the Company's 2015 IRP as a Class 3 DSM resource.[21] Unfortunately, PacifiCorp states that Class 3 DSM is not a selectable resource (unlike Class 1 and 2 DSM), a determination that Staff expects should change as PacifiCorp's smart grid integration advances.[22]

Staff notes that the success of Class 3 DSM programs relies on adequate outreach, and education and coaching of customers. Without these components to complement rate design, the TOU tariffs' efficacy is stunted. Consideration and design of these elements

[19] PacifiCorp Reply Comments, p.7

[20] U.S. Department of Energy, *Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*, at page 31, June, 2015.

[21] PacifiCorp refers to TOU and behavioral pricing programs as "Class 3 DSM."

[22] PacifiCorp's 2015 IRP, Volume II, Appendix D, at page 66, March 31, 2015.

originates in the Company's overall DSM planning, which is an element of the IRP. Until these programmatic issues are resolved, Class 3 DSM will not be a viable resource in portfolio planning, a situation that deprives ratepayers of a least-cost, least-risk resource.

II. Adherence to Guidelines

Order 89-507, amended by Order 07-002, establish the guidelines for the IRP process. Staff believes the Company has adhered to the Commission's guidelines with the following explanatory comments:

1. Guideline 1: Substantive Elements

Substantive Elements of least cost planning:

1. All resources must be evaluated on a consistent and comparable basis.
2. Risk and uncertainty must be considered
3. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
4. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Staff believes the Company has adhered to this Guideline, given the knowledge it had at the time of preparation and analysis. However, as noted by Staff and other parties, there is a high level of expectation that PacifiCorp will continue to analyze all reasonable options for compliance with environmental regulations in a way that both shields ratepayers from undue rate impacts and reflects Oregon's energy policies.

2. Guideline 5: Transmission

> *"Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability*."

Staff expects that the Company will consider the benefits represented by the freeing up of transmission capacity as a result of plant closures in forthcoming IRPs. As compliance with Regional Haze, Clean Power Plan and Oregon statutory requirements brings about coal generation plant closures, the transmission capacity that becomes available has great benefit to the system. This benefit should be clearly reflected in the IRP analysis.

Staff also recommends that the Commission require PacifiCorp to update the dynamic transfer capability between PacifiCorp's east and west balancing authorities to reflect recent changes in capability.

Finally, Staff recommends that the Commission require PacifiCorp to update its portfolio analysis to reflect the potential benefits of the formation of an RTO between PacifiCorp and the California ISO. Staff is encouraged by the level of potential benefits to ratepayers that such an action could have in light of the California ISO and PacifiCorp news release issued on October 13, 2015.[23] No discussion or analysis of this development was included in the present IRP. Staff would like to see such an analysis in the next IRP update.

3. Guideline 6: Conservation

Class 2 DSM

Acquisition of Class 2 DSM is the most significant resource investment within the action plan beyond Front Office Transactions. As such, it warrants additional analysis regarding its relative impact to the total portfolio and an understanding of how the timing of resource acquisition could impact the relative risk of the overall portfolio.

The accelerated acquisition path has historically been better aligned with actual efficiency acquisition in Oregon than the base case DSM annual selections within the preferred portfolio. Both ODOE and Staff recommended in Opening Comments that the Company run the accelerated DSM portfolios through the risk model to better understand the impact of aggressive EE acquisition as compared to that under base case conditions.

The Company's IRP modeling capabilities provide all stakeholders with a means to better understand how and if the tempo of DSM acquisition can affect the least cost, lowest risk long term resource plan. Therefore, Staff recommends that for the IRP update, the Company provide risk model results for the preferred portfolio assuming base case DSM and a comparison model run of the preferred portfolio with accelerated DSM.

The Company characterizes the selected energy efficiency resource by year in terms of energy (GWh) in the Action Plan along with a nameplate capacity for that incremental resource. For greater efficiency in reviewing and understanding the Action Plan, the Company should expand the presentation to include the winter and summer peak demand capacity values associated with each annual energy savings target. This would

[23] See https://www.caiso.com/Documents/WesternGridIntegrationCouldProduceSignificantCostSavings-EnvironmentalBenefits.pdf

then directly show how the selected energy efficiency bundles are also contributing capacity towards the key resource planning times of coincident and system peak demand. This expansion of capacity characterization would allow for ease of understanding by stakeholders and Staff as to how much of the selected Class 2 DSM resource is assumed to be available during seasonal peak planning hours.

Staff encourages the Company to consider developing proposals for four pilot programs. The four suggested DSM pilots would include:

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.
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.

Staff is appreciative of the Company's willingness to work with stakeholders in the 2017 IRP process to address future enhancement ideas, as noted in PacifiCorp's Reply Comments.[24] Included in those future enhancements should be: more comprehensive inclusion of Oregon existing and potential EE resource along with the other five states in the Plan; consideration of an alternate method for bundling measures by levelized cost after cost credits are applied; and ensuring a connection between the work of the Northwest Energy Efficiency Alliance (NEEA) in emerging technology development is reflected in the conservation potential assessment.

4. Guideline 12: Distributed Generation

Distributed Energy Resources (DERs)

As discussed in its Opening Comments, Staff anticipates that PacifiCorp will have a more robust and comprehensive analysis of the benefits that DERs like solar photovoltaic systems can offer to system operations in future IRPs. Such benefits include avoided energy and capacity resource needs as well as deferred transmission and distribution infrastructure.

Staff recognizes these values are not fully captured in PacifiCorp's 2015 IRP, but in order to successfully choose a "least cost, least risk" preferred portfolio in future IRPs, these additional benefits will need to be identified and used in the analysis.

Staff appreciates the efforts made by the Company to provide the distribution potential study and incorporate some of the results into the analysis. Staff continues to question the potential study assumptions and results that appear to offer limited DG capability. Staff looks forward to continued in-depth analysis regarding the achievable DG potential in the Company's next IRP.

[24] PacifCorp's reply comments, p. 17

III. LC 57 Action Items

At the conclusion of PacifiCorp's previous IRP docket, LC 57, the Commission issued Order 14-252, acknowledging the Company's 2013 IRP and adding several directives and Commission recommendations. Below are Staff's comments on the Company's progress in pursuing these items.

Coal Plant Compliance and Pollution Control
PacifiCorp was directed to provide quarterly updates to the Commission and guidance for data to include in future IRPs. The Commission also directed the Company to offer a series of workshops to discuss compliance strategies at specific plants. Staff believes the Company has complied with the Commission's directives.

111(d) assessment
The Commission directed the Company to work with stakeholders to develop the analysis regarding 111(d) compliance. Staff believes that PacifiCorp has adequately included stakeholders in the process. However, as noted in these comments, Staff and other parties have a concern over the proper modeling of 111(d) compliance in the next IRP now that the EPA rule is final.

Coal Plant Screening Tool
The Commission directed the Company to include an updated version of the screening tool in the filing. The Company did so.

DSM Related Recommendations
In Order 14-252 the Commission recommended that PacifiCorp:

> • *Provide twice yearly updates on the status of DSM IRP acquisition goals to the Commission in 2014 and 2015, including a summary of DSM acquisitions from large special contract customers. Summarize where efforts have deviated from previously agreed upon action items and report on progress toward specific DSM targets for all states other than Oregon.*
>
> • *Include in the 2014 conservation potential study information specific to PacifiCorp's service territory for all states other than Oregon that quantifies how much Class 2 DSM programs can be accelerated and how much it will cost to accelerate acquisition.*
>
> • *Include a PacifiCorp service area specific implementation plan as part of the 2015 IRP filing. At twice yearly updates to the Commission, provide a summary of savings potential, gaps and how PacifiCorp's specific implementation plan and programs are achieving the identified potential.*
>
> • *In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state.*

Staff is satisfied that the OPUC comments related to Class 2 DSM in the 2013 IRP have been addressed; specifically:

- PacifiCorp provided updates on the status of the DSM IRP acquisition goals to the Commission in 2014 and 2015 at public meetings held on August 6, 2014, December 3, 2014, and March 10, 2015;
- The conservation potential study included analysis of how much DSM resource could be accelerated and how much it would cost to do so for all states;
- Service area specific implementation plans were provided within the Plan; and
- Yearly energy and capacity from Class 1 and Class 2 DSM acquisition targets were provided by state.

IV. IRP Action Items

The Company offers the following Action Items for the time period 2015-2019:

Action Item 1 – RPS related actions

a) *RPS Compliance – the Company will continue to pursue unbundled RECs to meet RPS requirements*
b) *REC Optimization – the Company will sell older RECs not required for compliance*

Staff supports a least-cost approach to managing the Company's REC bank. However, Staff is of the opinion that these actions should be considered normal business practice and do not require acknowledgement.

c) *Fulfillment of Solar Capacity Standard through an RFP*

The Company's action item to fulfill its solar compliance obligation through the "request for proposal" (RFP) process is reasonable and it helps assure that the compliance will be come at the least cost and risk. Staff recommends acknowledgment of Action Item 1(c).

Action Item 2 – Front Office Transactions
The Company plans to meet summer peaks in the near term with short-term firm purchases. Staff supports this Action Item but does not believe it requires Commission acknowledgement as it reflects normal good business practice and is not a major resource acquisition.

Action Item 3 – DSM Actions
a) *Pursue a west-side irrigation load control pilot*

Staff supports an irrigation load control program but is not convinced a pilot is necessary. Irrigation load control programs are well-established elsewhere and Staff believes the Company could adopt such a program without the need for a pilot. Nevertheless, Staff agrees a pilot program would be a positive addition to the Company's current offerings. Staff recommends acknowledgement of Action Item 3(a).

In addition Staff recommends the Company establish a pilot for Class 1 space or water heating for residential and commercial customers in Oregon. Such a pilot would allow the Company to gain experience in controlling program costs, developing methods of delivering the service, and determining effective messaging for this and future programs.

b) Acquire cost effective Class 2 DSM

The Company proposes to acquire 2,385 GWh of Class 2 DSM between 2015 and 2018, a substantial portfolio-wide increase (37 percent) compared to the 2013 IRP Action Plan. The Company credits this identification of additional cost-effective EE largely to increased lighting potential, specifically growth in LED opportunities. Concerns from Staff and other stakeholders from the last IRP regarding Oregon ratepayers being burdened by a lack of sufficient DSM in other states will begin to be addressed if these portfolio wide targets are met. Staff is supportive of these short term action plan targets as being well informed by thorough analysis for current commercially-available resources.

Since Staff and Oregon stakeholders continue to be interested in tracking the Company's progress in growing efficiency programs in other states, Staff recommends continuing to have the Company report to the Commission two times per year on progress in other states towards these new, higher goals.

Staff recommends acknowledgement of Action Item 3(b), and proposes the following additional recommendations:

- *Continue to provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2016 and 2017 at regular public meetings.*

- *Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Class 2 DSM annual energy savings targets.*

- *For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes.*

Action Item 4 – Coal Resource Actions

a) Naughton Unit 3 – Issue an RFP to procure gas transportation and continue plans for gas conversion.
b) Dave Johnston Unit 3 – continue on path to avoid SCR[25] and shutdown in 2027
c) Wyodak – Continue legal actions to avoid SCR
d) Cholla Unit 4 – Continue efforts to avoid SCR and cease coal operation in 2025

Although these action items do not represent resource acquisition *per se*, Staff believes that the Company's actions represent an active involvement in the deferment or avoidance of a large enough cost to be considered an "avoided major resource

[25] "Selective Catalytic Reduction" (SCR)

acquisition" or certainly an avoided significant capital expense. In this light, Staff recommends acknowledgement of Action Items 4(a-d). However, as noted in its Opening Comments, Staff believes the economic case for Naughton's conversion versus shutdown is close enough to demand ongoing analysis.

Action Item 5 – Transmission Actions

The Company proposed the following transmission action items:

Table 1: Action Items Discussed by Staff

Action Item #	Action Item Category	Action Item
5(a)	Energy Gateway Permitting	Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: - For Segments D, E, and F, continue funding of the required federal agency permitting environment consultant actions to achieve final federal permits. - For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. - For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
5(b)	Wallula to McNary 230 kilovolt Transmission Line	Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue support the permitting process for Walla Walla to McNary.

Action Item 5(a): Energy Gateway Permitting

PacifiCorp requests acknowledgment of this action item, which generally covers continued permitting and support of the pre-construction phases, both referred to by Staff in these comments as "permitting efforts" or "permitting actions" of the Energy Gateway project (Energy Gateway).

PacifiCorp defines the Energy Gateway as "an ambitious, multi-year, multi-billion dollar investment plan that will add approximately 2,000 miles of new transmission lines across the West."[26] The Company is requesting acknowledgement of permitting actions for the following segments: Windstar to Populus (W2P or Segment D),[27] Populus to

[26] See www.pacificorp.com/energygateway.

[27] Segment D is part of the Gateway West project. This segment "will stretch approximately 488 miles starting at the Windstar substation near Glenrock, Wyoming, proceeding south to Medicine Bow and then spanning across southern Wyoming to the Populus substation near Downey, Idaho. This segment will include seven expanded or new substations and will enable access to existing and new generating resources, including wind, and will deliver electricity from these sources to customers throughout both companies' service territories." (See http://www.pacificorp.com/tran/tp/eg/gw.html.) The anticipated in-service date for this project is between 2019 and 2024 (see PacifiCorp's 2015 IRP, Volume I, page 57).

Hemingway (P2H or Segment E),[28] Aeolus to Mona (A2M or Segment F),[29] and Boardman to Hemingway (Segment H).[30]

Staff recognizes the uncertainty in developing these segments, given that their anticipated in-service dates are in 2019 and beyond. However, such uncertainty should not hinder the Company's efforts to continue exploring the projects in light of the preliminary benefits of these segments as presented in the Company's confidential response to Staff DR 67 and other benefits such as enabling the Company to access additional resources. Therefore, Staff recommends that the Commission acknowledge Action Item 5(a), as modified for simplicity.

Staff Final Comments' Recommendation

Staff recommends acknowledging the Company's Action Item 5(a) with the modifications represented in Table 4.

<u>Action Item 5(b): Wallula to McNary 230-Kilovolt Transmission Line</u>

Staff thoroughly analyzed this project in its Opening Comments from an economic point of view and stated that it cannot support an acknowledgment this project because of its poor economic justification.[31]

In its Reply Comments,[32] the Company emphasized that this project is driven by its Open Access Transmission Tariff (OATT) federal obligation. The Company also commented that it has a point-to-point transmission service agreement to provide 25 MW of transmission service by December 31, 2015, over the new transmission line pursuant to requirements of its OATT.

During subsequent discovery, the Company disclosed that it has investigated several alternatives to comply with the FERC transmission requirements represented in its OATT. The Company has received requests for transmission of wholesale power that,

[28] Segment E is part of the Gateway West project. This segment "originates at the Populus substation near Downey, Idaho, and includes two transmission lines that run approximately 502 miles across Idaho to the Hemingway substation near Melba, Idaho. The Populus to Hemingway segment will include five expanded or new substations, and will enable access to existing and new generating resources, including wind, and will deliver electricity from these sources to our customers."(See http://www.pacificorp.com/tran/tp/eg/gw.html.) The anticipated in-service date for this segment is between 2019 and 2024. (See PacifiCorp's 2015 IRP, Volume I, page 57.)

[29] Segment F is part of the Gateway South project. This segment extends "approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the new Clover substation near Mona, Utah." (See PacifiCorp 2015 IRP, Volume I, page 51 and http://www.pacificorp.com/tran/tp/eg/gs.html.) The anticipated in-service date of this segment is between 2020 and 2024. (See PacifiCorp's 2015 IRP, Volume I, page 57.)

[30] Segment H is part of the Gateway West project. This segment is a 500-kilovolt line that would run approximately 300 miles from a new substation proposed near Boardman, Oregon, to the Hemingway substation near Melba, Idaho, southwest of Boise, Idaho." The anticipated in-service date is sponsor-driven. (See PacifiCorp's 2015 IRP, Volume I, page 57.) Per Idaho Power Company's (Idaho Power) 2015 IRP, the in-service date is expected to be in 2021 or beyond. (See Idaho Power 2015 IRP, Volume I, page 68 at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf.)

[31] See page pages 25 through 31 of Staff Opening Comments.

[32] Generally, see pages 19 through 22 of PacifiCorp Reply Comments.

according to its OATT, it is obliged to supply. The Company explored providing this service by re-conductoring and otherwise enhancing the existing transmission line. However, any upgrades to the existing line would entail a transmission outage of the line and a need to purchase replacement capacity and energy. The Company's analysis shows that this approach is about 30% more expensive than building a new line.

The Company also reported that it attempted negotiations with the parties requesting the wholesale power to either have them defer the request or to provide funding towards the project. Neither negotiation path proved successful, leaving the Company with no further option than to either build the needed transmission line, or risk being in non-compliance with their FERC OATT.

After evaluating all of the potential compliance paths, the Company concluded that constructing the new Wallula to McNary Transmission Line was the least cost option for meeting its obligation per its OATT.

The Company further stated that it would not object to the Commission acknowledging Action Item 5(b) with clarifying language to reflect that the action item is concerned with regulatory compliance, not economics.

Regarding the Company's request to continue to support the permitting process for the Walla Walla to McNary transmission line, Staff recommends the continued permitting efforts of the Walla Walla to Wallula segment because of the potential future customer needs.

Staff Final Comments' Recommendation
Staff recommends acknowledgement of Action Items 5(a) and (b), with the modifications represented in Table 4.

Table 4: Staff-Proposed Action Items for PacifiCorp 2015 IRP

Action Item #	Action Item Category	Action Item
5a	Energy Gateway Permitting	Continue permitting Segments D, E, F, and H until PacifiCorp files its 2017 IRP.
5b	Wallula to McNary 230 kilovolt Transmission Line	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

V. Concluding Comment and Recommendation

Staff recommends acknowledgement of PacifiCorp's 2015 Action Plan with the recommendations contained herein, and summarized below:

Action Item	Description	Staff Recommendation
1(a)	RPS – pursue unbundled RECs	No acknowledgement required
1(b)	REC Optimization – sell older unneeded RECs	No acknowledgement required
1(c)	Fulfillment of solar capacity standard via RFP	Acknowledge
2	Front Office Transactions	No acknowledgement required
3(a)	Pursue a west-side irrigation load control pilot	Acknowledge with Recommendations
3(b)	Acquire cost effective Class 2 DSM	Acknowledge with Recommendations
4(a-d)	Coal related actions	Acknowledge
5(a)	Energy Gateway permitting	Acknowledge
5(b)	Compliance with FERC- Wallula to McNary	Acknowledge with amendment

Recommendations

In addition to acknowledgement of the Action Plan items, Staff recommends that the Commission direct the Company to:

- Include sensitivity studies around solar costs (high, base, low cost cases);
- Evaluate and consider the benefits of freed-up transmission due to plant closures;
- Implement ODOE recommendations:
    - Include the constraints needed for 111(d) compliance in all cost risk analysis ("PaR" analyses);
    - Estimate the effects of 111(d) compliance on western wholesale power prices;
    - Use the same Regional Haze assumptions when directly comparing portfolios;
    - Perform more risk analysis on portfolios that include accelerated EE as a resource;

- Include more robust analysis regarding the west BA winter peak load/resource balance and portfolios to meet this peak load;
- Provide quantitative justification planning for the planning reserve margin of 13 percent;
- Encourage the Company to design several new DR programs, including:
    - An irrigation load control program;
    - A residential direct load control pilot (water heaters, AC, thermostats, etc);
    - An aggregator-led commercial DR pilot;
    - An industrial load control pilot that operates to address peak load reduction and not restricted in use to emergencies and enhanced reliability;
    - An innovative time-of-use rate pilot proposal that does not need to leverage AMI infrastructure in order to realize benefits to the customer and the utility.
- Provide quantitative justification for assumed levels of trading hub liquidity and depth;
- Utilize the BAAL NERC standard in forthcoming wind integration studies;
- Provide alternate 111(d) compliance paths, including mass-based solutions, with stochastic analysis for each;
- Update the available dynamic transfer capability between PacifiCorp's east and west balancing authorities in the modeling;
- Include an analysis of the benefits and costs of forming a Regional Transmission Operator (RTO) by partnering with the CAISO;
- Perform stochastic modeling on all portfolios with accelerated DSM;
- Continue to provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2016 and 2017 at regular public meetings;
- Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Class 2 DSM annual energy savings targets;
- For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes.

This concludes Staff's Opening Comments.

Dated at Salem, Oregon, this 15th day of October, 2015.

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