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DIVISION COMMENTS ON PACIFICORP'S 2013 IRP

To: Utah Public Service Commission

From: Utah Division of Public Utilities
Chris Parker, Director
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Date: September 9, 2013

Re: Docket No. 11-2035-01, PacifiCorp's 2011 Integrated Resource Plan

RECOMMENDATION (DO NOT ACKNOWLEDGE)

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) not acknowledge PacifiCorp's 2013 Integrated Resource Plan (IRP) and Action Plan. As explained below, the Division finds the 2013 IRP does not fully meet the Standards and Guidelines,[1] and falls short of meeting the directives from the Commission's April 1, 2010 IRP Order.[2] In addition, the Division cannot verify the adequacy of the Action Plan nor can the Division either confirm or deny that the plan results in a preferred portfolio that is the least-cost, least risk portfolio. Finally, the Division suggests improvement measures for future IRPs and requests the Commission consider and implement such measures.

[1] Docket No. 90-2035-01, Report and Order, June 18, 1992.
[2] Report and Order, Docket No. 11-2035-01, March 22, 2012.

BACKGROUND

On April 30, 2013, PacifiCorp (Company) filed its 2013 IRP pursuant to the IRP Standards and Guidelines adopted in Docket No. 90-2035-01.[3] (The Company requested, and received approval from the Commission for an extension of time, allowing it to file the 2013 IRP on April 30, 2013, rather than on March 31, 2013.)[4] The Company requested the Commission acknowledge the 2013 IRP in accordance with Commission rules and fully support the IRP conclusions, including the proposed action plan.

On May 17, 2013, the Commission convened a Scheduling Conference that resulted in the Commission's June 3, 2013, Scheduling Order and Request for Comments. In addition, the Commission held a Technical Conference on August 27, 2013, that included a public session in the morning that was a high level overview of Volumes I and II, and a confidential afternoon session focusing on Volume III.

In response to the Commission's Request for Comments, the Division provides the following IRP comments to the Commission, with a focus on whether the 2013 IRP complies with prior Commission IRP orders and standards. The Division's comments are organized as follows: (1) General Comments on the 2013 IRP, (2) Conformance with the Commission's 2011 IRP Order (3) Compliance and Acknowledgement, and (4) Conclusion. This memorandum also contains an Appendix titled "A Broad Critique of the IRP Process, A Suggested Solution and Changes to IRP Standards and Guidelines." As the title indicates, the Appendix A presents the Division's critical views of what the current IRP process has evolved into. Appendix B presents an alternative to the current process along with a redline revision of the Commission's Standards and Guidelines that conforms to the Division's recommended process.

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[3] Id.
[4] Correspondence from PacifiCorp, January 8, 2013 and Order Granting Extension of Time, Docket No. 13-2035-01, February 12, 2013.

General Comments on the 2013 IRP

The Company used an updated July 2012 load forecast in the modeling and analysis of the 2013 IRP, which is a significant driver in the resource portfolio modeling of the IRP. The 2013 IRP load forecast is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The lower load stems from prolonged recessionary impacts, as well as industrial self generation taking advantage of low natural gas prices. The industrial load forecast in this IRP uses regression analysis in place of probability assessment of customer-provided forecasts used in prior IRPs.

Using a 13 percent planning reserve margin, the capacity expansion model results show a system capacity deficit of 824 megawatts in 2013, a drop of 57 percent compared to the 2011 IRP and down 39 percent from the 2011 IRP Update. By the year 2022, the system reaches a capacity deficit of 2,308 megawatts. During the front ten years, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent, with energy load growth forecasted at 1.1 percent per year.

The Preferred Portfolio resources are intended to meet capacity requirements at the time of system peak through the year 2022. Resources in the first ten years are met largely by energy efficiency acquisitions and front office transactions. The Company's 2013 IRP Company's Action Plan identifies the steps the Company will take during the next two to four years to implement its plan and includes action items that focus on accelerating the acquisition of cost effective demand side management (DSM) measures. The Company's Preferred Portfolio includes 650 megawatts of incremental wind resources in the 2024 to 2025 timeframe that contribute to the Company's meeting assumed renewable portfolio standards (RPS) obligations. Near-term renewable resources include small scale utility solar resources to meet Oregon requirements and distributed solar resources as part of Utah's solar incentive program.

The RPS requirements were developed upfront in the 2013 IRP with the introduction of an RPS Scenario Maker model--an Excel spreadsheet tool that was used to develop RPS compliance renewable resource schedules based on state-specific RPS policies.

Some of the other changes that are new to the 2013 IRP include the following:

- The System Optimizer (SO) and Planning and Risk model (PaR) have been combined into a single model through the Enterprise Production Model (EPM) interface. The change made it so that the results from the SO did not need to be manually entered into the PaR model.

- Energy Gateway transmission investments were integrated directly into the portfolio modeling process by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. As a result, 94 core case resource portfolios were produced in this IRP. In the 2011 IRP the Energy Gateway transmission investments were calculated before the resource portfolio modeling.

- The System Operational and Reliability Benefits Tool (SBT) was created to identify and quantify transmission benefits that are not captured using traditional production cost modeling used in the IRP—the benefits that are incremental to those identified in the resource portfolio modeling process. The Company has formed a workgroup to study the new tool and evaluate metrics that comprise the SBT.

- The 2013 IRP includes for the first-time core case resource portfolios developed assuming accelerated acquisition of energy efficiency resources. In the 2011 IRP, energy efficiency resources were grouped into nine different cost levels, whereas in this IRP modeling was performed using 27 different cost levels to represent energy efficiency resource opportunities in each state. The Company will continue to validate and review the cost and risk analysis of these portfolios.

- The Company builds upon its 2011 IRP analysis of coal investment decisions by integrating coal unit environmental investment decisions into the portfolio development process. Confidential Volume III of the 2013 IRP shows the completed detailed financial analysis of near-term investment decisions.

CONFORMANCE WITH THE COMMISSION'S 2011 IRP ORDER[5]

In its 2011 Report and Order, the Commission identified deficiencies in the Company's 2011 IRP and provided guidance and directives to the Company for future IRPs. The Division's comments in this section focus on whether the Company's 2013 IRP complies with the Commission's directives, which are classified as (A) Insufficient Adherence to Guidelines and (B) Other Suggested Improvements for Future IRPs.

Insufficient Adherence to Guidelines

According to the Commission's 2011 IRP Order, the 2011 IRP is deficient in the following areas, and the Commission directed the Company to make improvements in its future IRPs:

a) <u>Preferred Portfolio Evaluation Criteria</u>. The 2011 IRP is deficient in providing sufficient analysis of the tradeoffs between costs, risks customer rate impact, supply reliability, resource diversity, and the future uncertainty of greenhouse gas and RPS policies, particularly for the Preferred Portfolio. In the future, the Company should provide all stochastic portfolio performance measures for the Preferred Portfolio and identify the additional cost associated with addressing the non-modeled objectives cited by the Company, i.e., social concerns and cost recovery risk of geothermal resources. As required by Guideline 4.h., the Company should identify who will bear this financial risk, shareholders or customers.

Findings: The Division provides comments on this standard in detail below (on page 17, Final Portfolio Screening). The Company did not comply with this directive; however,

[5] Report and Order, Docket No. 11-2035-01, March 22, 2012.

the Company did comply with portions of this criterion with respect to geothermal resource modeling and a description of risk. Geothermal resource recovery risk is addressed by assuming that geothermal resource acquisition would be in the form of Power Purchase Agreements with size and location of these resources based on responses to a Request for Information issued on April 16, 2012. The cost recovery risk issue is addressed in the Action Plan (Chapter 9 on page 281), which describes three types of risk: stochastic risk assessment, capital cost risks, and scenarios risk assessment.

After the Preferred Portfolio was determined (case EG-2, C07), the Company substituted renewable energy credits (RECs) in place of wind to meet the Washington RPS obligation. The Company named its new Preferred Portfolio case EG-2, C07(a). The guideline states that the Company needs to identify the additional cost associated with addressing the non-modeled objectives, such as the Washington RPS. The IRP does not clearly report on the expected cost of meeting the Washington RPS objective, and the Division understands that future REC price risks (e.g., volatility) were not modeled in this IRP, which they would need to be for planning purposes. Even with REC prices being very low at the current time, the Company needs to provide an expected cost of meeting RPS requirements through RECs if it continues to plan to use them and provide an expected range for REC prices over time, as REC prices may increase in the future.

The Company fell short of meeting this Commission directive. In addition, this was another step that the Company performed on its own, after the Preferred Portfolio was determined, without vetting the screening exercise before stakeholders at the beginning of the IRP process. This is a violation of the Commission's procedural guideline 4 (a) below.

b) Coal Plant Retirement. The initial analysis in the 2011 IRP is insufficient for determining the various costs and benefits of extending the lives of coal plants through continued investment versus retiring the plans and investing in alternative strategies for meeting customer demand.

Findings: In Confidential Volume III the Company builds on the modeling techniques from the 2011 IRP and now integrates coal unit environmental investment decisions in the development of resource portfolios to determine whether investments are cost effective in relation to other compliance alternatives. The 2013 IRP analysis is an improvement over its 2011 coal plant study and complies with this requirement.

c) Energy Gateway Transmission Analysis. The Company's analysis in the 2011 IRP is insufficient to determine whether the full Energy Gateway project is cost effective, considering risk and uncertainty. The Waxman-Markey proposal and its effect on the type, timing, and magnitude of resource additions, should be evaluated. The Company's existing system should represent only facilities which have already received a certificate of convenience and necessity (where required) or for which the Company has a binding contract in place. All other facilities should be included in core or sensitivity cases as options.

Findings: The Company complied in that it did not include facilities in its existing system that did not have a certificate of convenience and necessity or a binding contract in place. In the 2013 IRP, Energy Gateway transmission investments are integrated into the portfolio modeling process. The Company replicated the development of resource portfolios among five different Energy Gateway transmission scenarios. In addition, the System Operational and Reliability Benefit Tool (SBT) identifies, measures, and monetizes benefits that are not captured using production cost dispatch models. The Company did not complete the stochastic risk analysis of the last three Energy Gateway scenarios—EG-3 through EG-5.

d) Geothermal Resource Exclusion. In its next IRP, the Company should evaluate the geothermal resource cost recovery risk directly. Since the geothermal cost already includes a development cost estimate, the Company in future IRPs could evaluate higher estimates, and compare this risk with the risks of other portfolios. The Action Plan contains no action item to address the cost recovery risk issue. The Company should also identify the actions it is taking to address these issues, i.e., obtaining regulatory or legislative relief in other states, and include an action plan item in the IRP update to this end.

Findings: As previously mentioned, geothermal resource recovery risk is addressed by assuming that geothermal resource acquisition would be in the form of Power Purchase Agreements with size and location of these resources based on responses to a Request for Information issued on April 16, 2012. Chapter 9, page 281, contains a narrative on the cost recovery risk issue.

e) Rate Design. The Company should include a discussion of rate design as required in Guideline 4.g. The discussion should describe how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.

Findings: A discussion of rate design can be found in Volume I, Chapter 3, pp. 48-50.

Other Suggested Improvements for Future IRPs

a) Public input process. The criteria the Company previously identified and addressed by manually modifying a given portfolio at the end of the evaluation process should be identified at the beginning of the IRP process. The next IRP should identify the cost tradeoffs to achieve different levels of performance with respect to the public interest criteria. The Company in its next IRP should spend more effort developing comparable cases and ensuring consistent and comparable evaluation of alternative resources and should allow public input for developing a strategy to specify cases and alternative "future" scenarios.

Findings: PacifiCorp improved its public input process in many ways in this IRP cycle. For example, the Company held 15 public input meetings, several conference calls, and state meetings, soliciting stakeholder input and comments where possible. The Company allotted times in stakeholder meetings for questions—the most useful improvement to the process. In addition, the Company provided written responses to questions when requested or when there was not enough time at meetings to address some of the parties' questions. The Company compared portfolios to achieve different levels of performance using resource diversity and generator CO_2 emissions as the public interest criteria.

However, the Company did not previously identify and address with stakeholders, prior to the end of the process, the substitution of RECs for Washington wind and the substation of case EG-2, C7 in place of case EG-2, C15 (the accelerated DSM portfolio).

b) Renewable resource assumptions. The Company should perform sensitivity and scenarios analyses around key renewable resource cost assumptions in its next IRP. The Company should prepare a new wind integration study in the next IRP. This includes a technical review committee. Any Potentials Study used to inform the IRP should be filed concurrently with the IRP.

Findings: The Company performed a sensitivity case (S-9) around targeted renewable resources. The Company filed its wind integration study that can be found in Appendix H of Volume II, and a Technical Review Committee provided a brief report of on its review of the wind integration study (May 31, 2012 meeting report). The Company filed the accompanying potentials studies used in this IRP cycle, including the Demand-side Management Potentials study, an updated stochastic loss of load probability study prepared by Ventyx (Volume II, Appendix I), a 2011 Geothermal Information Request that was posted for stakeholder review on the Company's IRP website, and an energy storage screening study for integrating variable energy resources that was also posted for stakeholder review on the Company's IRP website.

c) <u>Discount for combined cycle combustion turbine</u>. The Company should provide sensitivity analyses, including stochastic analyses, to examine the impact of the CCCT capital cost credit adjustment on the selection of wind and solar resources to confirm the cost credit adjustment is in the public interest. Is it lower cost to build CCCTs to displace coal generation to reduce CO_2 costs, or to replace coal with renewable resources?

Findings: The Division is not aware of where the Company made this particular adjustment, but notes that the Company did develop 12 sensitivity cases that are in Chapter 8 of Volume I of the 2013 IRP.

d) <u>Range of externalities</u>. The Company should continue the discussion on specific externality values in the IRP public input process to determine a reasonable and manageable range of values.

Findings: The Company discussed with stakeholders the approach for modeling externality costs with CO_2 price scenarios in the case definitions and when interpreting the model results.

e) <u>Hedging practice and reliance on wholesale market purchases.</u> The Company should continue to provide the western market analysis in support of its reliance on market purchases and explore ideas for addressing other issues.

Findings: The Company provided the Western Electricity Coordinating Council's (WECC) Load and Resource Deficit Report and Western Resource Adequacy Evaluation, described in Volume II, Appendix J to comply with this directive.

f) Planning reserve. The Company should continue analysis of this issue, both through LOLP and tradeoff analysis, and the testing of the 1.5 percent adjustment to the LOLP study.

Findings: The Company held a workshop to discuss the planning reserve margin on August 2, 2012. On September 24, 2012, the Company held a conference call to discuss planning reserve margin modeling, and the study results were discussed. (See Volume II, Appendix I Stochastic Loss of Load Study). PacifiCorp's planning reserve margin study estimates the marginal cost of reliability for different planning reserve margin levels, using the stochastic Expected Unserved Energy (EUE) measure.

g) Load forecast. The Company should consider hosting a public input meeting to discuss long-term load volatility, long-term load growth uncertainty, and to respond to the five GDS recommendations. We prefer the Company include a ten-year history of monthly energy, coincident peak, and non-coincident peak, by state, in all future IRPs.

Findings: At the September 12, 2012 stakeholder meeting, the Company addressed the load forecast and is incorporating three of the five GDS recommendations in the 2013 IRP. The Company did not obtain economic reporting from vendors other than Global Insights, claiming it would be cost prohibitive and would put the Company in the position of choosing among the vendor forecasts. In addition, the Company did not initiate an investigation into its line loss projection methodology in this IRP. The Company did include ten-year state historical load information in 2013 IRP that can be found in included in Appendix A in Volume I.

h) Reliability "Energy Not Served" (ENS). The Company should continue to provide sensitivity analysis and to discuss this issue in future IRP meetings. The reliability measure is intended to identify the cost differences between portfolios. The Company could host a discussion regarding this measure and the extent to which the ENS measure is accomplishing this goal.

Findings: The ENS assumptions are tied to the Federal Energy Regulatory Commission price cap and are incorporated in all portfolio simulations. (See item F above).

i) Resource Acquisition Path and Decision Mechanism. The Company should explore UAE's suggestion to include the cost increase of alternative acquisition strategies in its next IRP.

Findings: In Volume I on pages 264 to 268, the Company presents its alternative path analysis pursuant to Commission Guideline 4g. The Division notes that while this analysis may still fall short of what was originally envisioned by this guideline, Table 9.2 is an excellent summary of actions the Company may undertake should the future start to turn out significantly different than anticipated as reflected in the Company's preferred portfolio.

j) Demand side management (DSM) resources. The Company should conduct a meeting to explain its development of DSM resource bundles. The Company should address its plans to closely monitor DSM resource acquisitions for adherence to IRP forecasts in its next IRP. The Company should file any Potentials Study used to inform an IRP concurrently with the IRP.

Findings: The Company filed the Cadmus Potentials Study concurrently with this IRP. Public input meetings covering DSM were held on June 20, 2012 and August 14, 2012. The Company's Action Plan addresses monitoring DSM resource acquisitions. (See item 7a).

The Division of Public Utilities commends the Company for its modeling treatment of the DSM resources in the IRP. As in the previous IRP, the Company modeled energy efficiency resources as resources that compete with the supply side resources in the development of least cost/least risk portfolio. However, new to the 2013 IRP, the Company included accelerated DSM resource acquisition in some of the core cases. The Company expanded the representation of the attributes of energy efficiency, which influences the selection energy efficiency resources in any given portfolio. In addition, the Company increased the number of cost steps that delineate groupings of different cost levels from 9 to 27. This modeling effort resulted in that the accumulated acquisition of incremental energy efficiency resources that make up 67 percent of currently forecasted load growth from 2013 levels by 2022.

There are uncertainties surrounding the accelerated acquisition of DSM resources, including those in incentive costs, administration costs, and delivery risk. Because of the uncertainties surrounding the results of this endeavor, the Division recommends that the implementation of the action items related to the accelerated acquisition of DSM be closely monitored. The Division also believes that the additional cost granularity (increase in the number of cost steps that delineate groupings of different cost levels from 9 to 27) may compromise the performance of the model. A detailed analysis should be performed to identify whether the results achieved with the additional cost granularity outweigh the effect of the additional granularity of costs on the model performance.

COMPLIANCE AND ACKNOWLEDGEMENT

In its review the Division next looked at the extent to which PacifiCorp's IRP and related Action Plan complies with each of the Procedures, Standards and Guidelines (Guidelines) stemming from the Commission's 1992 Report and Order in Docket No. 90-2035-01.[6] In doing so, the Division, as well as other parties, submitted formal data requests, verbal comments, and informal written comments to the Company throughout the cycle of the IRP.

[6] Report and Order on Standards and Guidelines, Docket No. 90-2035-01, June 18, 1992.

The Commission's procedural issues as contained in its Guidelines are stated below:

- The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.
- Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.
- Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.
- PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.
- Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.
- The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.
- Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.
- The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.
- The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.

The Division believes the 2013 IRP meets the Commission's procedural requirements and comments on its justification for adherence on the last item, the Company's Strategic Business Plan. The Division reviewed the Company's ten-year 2013 Business Plan in January of 2013. Since the 2013 Business Plan cycle, the following assumptions have changed: reduced loads, removal of wind resources consistent with use of renewable energy credit purchase for RPS compliance, decreased DSM and front office transactions due to a decrease in load, and an increase in distributed solar due to the Utah Solar Incentive Program. As a result, the Company's 2013 Business Plan differs from the 2013 IRP Preferred Portfolio.

In addition, the Company made improvements and updates to its System Optimizer model since the 2013 Business Plan that made it difficult to merge the previously selected portfolio with the new model inputs. For example, Class 2 DSM resources are configured in more detail in the 2013 IRP as compared to what was used to develop the 2013 Business Plan portfolio, thus making DSM resources incompatible with the current modeling system. In the 2013 IRP, the sensitivity case S-08 (simulating PacifiCorp's 2013 Business Plan portfolio in the current input setup) was removed due to incompatibilities in how Class 2 DSM resources were modeled in the 2013 IRP as compared to the Business Plan.

The Division commends the Company on making modeling improvements and realizes that incompatibility problems will occur from time to time as updates are made to the IRP modeling. The Company did not complete the Business Plan sensitivity case for the 2013 IRP, but provides categories of resources for the Business Plan in Table 8.12 of Volume I.

The Company restates in its 2013 IRP that the purpose of the Business Plan alignment is to: (1) provide corporate benefits in the form of consistent planning assumptions, (2) ensure that business planning is informed by the IRP portfolio analysis, and, likewise, (3) that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting; and (4) improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The Division recommends that, in order to meet this guideline in the next IRP, the Company should maintain the IRP schedule and perform the sensitivity analysis described above. The Division believes that the linkage between the Company's Business Plan and the IRP can be resolved in the next IRP now that the recent modeling updates have been completed and through process changes that we describe in the Appendix to this memorandum.

Standards and Guidelines

With respect to what is required and what must be included in the Company's IRP, the Commission's Standards and Guidelines address the heart of the IRP and are listed below:[7]

1. Definition:

Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.

2. The Company will submit its Integrated Resource Plan biennially.

3. The IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.

4. PacifiCorp's future integrated resource plans will include:

   a. A range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.

      i. The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-

[7] Id.

system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.

ii. Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.

b. An evaluation of all present and future resources, including future market opportunities (both demand-side and supply side), on a consistent and comparable basis.

i. An assessment of all technically feasible and cost- effective improvements in the efficient use of electricity, including load management and conservation.

ii. An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

iii. The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.

c. An analysis of the role of competitive bidding for demand- side and supply-side resource acquisitions.

d. A 20-year planning horizon.

e. An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.

f. A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

g. An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.

h. An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.

i. Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.

j. An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.

k. A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.

l. A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.

Based on the Division's review of the IRP and its participation throughout the 2013 IRP cycle, the Division finds that most of the above standards have been met in the Company's 2013 IRP. However, the exceptions that the Division points out below are significant and impact the optimality of the Company's Preferred Portfolio.

Optimality of the Company's Preferred Portfolio

Three-stage process. First, the Company did not perform the deterministic risk analysis as part of the Commission's three-step approach, which the Commission has repeatedly guided the Company on. The Commission's three-step approach has been a mainstay in recent Commission IRP Orders and has been spelled out in no uncertain terms. The Commission has asked the Company to fully implement the three-stage approach for developing its preferred portfolio, which includes the following three steps:[8]

(1) Identify optimal portfolios for a relatively broad, and consistently applied, set of fixed input assumptions.
(2) Subject the unique sets of these portfolios to stochastic risk analysis and identify superior portfolios with respect to the tradeoff between expected cost and risk exposure.
(3) Examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad fixed input assumptions.

In spite of this encouragement by the Commission, the Company did not perform the deterministic risk analysis and explains its justification for not performing the deterministic risk analysis below: [9]

[8] Docket No. 09-2035-01, Report and Order, April 1, 2010, p. 19.
[9] PacifiCorp's Response to UCE data request 3.9, September 3, 2013.

> The "superior" or top performing resource portfolios, as summarized in Volume I of the 2013 IRP; specifically Figure 8.25 at page 223, have similar resource types, timing, and quantities among the planning period most critical to influencing the 2013 IRP Action Plan. Given these similarities among the top performing portfolios, a deterministic risk analysis would not be productive in identifying cost consequences by subjecting them to a range of fixed input assumptions.

The Division does not accept this explanation as a reason to not follow the Commission's directive and believes that the Company erred in this regard.

Energy Gateway Scenarios. The Company did not complete the PaR model runs for the majority of EG-3 through EG-5 transmission cases due to time constraints. In addition, the Company excluded the core case C19 portfolio from the model runs. On the Company's behalf, many of the time constraints were due to peculiarities that arose as a result of the Company's improving and updating the modeling of the IRP. The case C19 was an alternative to Energy Gateway Segment D and was a third party transmission project (the Zephyr DC line). The Company cites the following reason for excluding case C19 as a pre-screening step: "The Zephyr DC line would provide no reliability benefits to PacifiCorp's existing transmission system and may require additional infrastructure additions to meet reliability for the existing system."[10] The case C19 should not have been included if the Company was not going to use it to begin with. The time spent generating portfolios that will be discarded could be spent exploring portfolios that are considered feasible. The results from the alternative Energy Gateway scenarios would have been helpful in validating the optimality of the Preferred Portfolio.

Final Portfolio Screening. The initial results of the System Optimizer and PaR runs, after a year's worth of work by multiple stakeholders show that Case EG2-15 is the Preferred Portfolio. While the Division is indifferent to which case the model selects (as long as the resulting portfolio chosen is the optimal solution), the Division is concerned that the quantitative analysis should lead to the optimal preferred portfolio. Case EG2-15, which included accelerated DSM, yielded the highest ranking risk-adjusted PVRR in the zero, medium, and high CO_2 cases. It

[10] PacifiCorp's 2013 IRP, Volume I, April 30, 2013, footnote 73, p. 216.

ranked number 1 in all three categories, while case EG2-C07 ranked number 8 in all three categories. In addition, the accelerated DSM case ranked above case EG2-C07 in cumulative CO_2 emissions in the zero, medium, and average CO_2 scenarios. In Tables 8.3 and 8.4 on pages 220-221 of Volume I, case EG2-C15 ranks significantly higher than case EG2-C07 in stochastic mean Energy Not Served and in Energy Not Served upper tail. Case EG2-C07 only outranks case EG2-C15 when high CO_2 prices are assumed. In addition, case EG2-C07 relies on considerably more front office transactions than case EG2-C15,[11] (which the Division has expressed concern over in the past).[12] The Company clearly states that the two C15 portfolios rank high in relation to other candidate portfolios,[13] yet the Company did not choose case EG2-C15. The reasons the Company claims are unsupported with analytical evidence, though they may be valid points. The Company states that case EG2-C15 was not selected as the preferred portfolio because of the following reasons:[14]

- The high level cost assumptions of accelerating DSM are uncertain.
- Ramp rates assumptions of accelerated Class 2 DSM are untested.
- The Company is reluctant to select a portfolio that excludes CCCT resources.

The Commission has voiced its concerns with regard to the role of quantitative analysis in determining the optimal Preferred Portfolio and made the following explicit recommendations for the Company's IRPs:

> Therefore, we instruct the Company to ensure the IRP explicitly produces the quantitative analysis necessary for regulators to understand the cost consequences of mitigating any risky or uncertain event including any Company corporate resource planning decision. The Company bears the risk for any unreasonable cost to ratepayers associated with its decision to change the quantity and type of resources it procures based on asserted but unexamined risks.[15]

[11] PacifiCorp's 2013 IRP, Volume I, April 30, 2013, p. 206.
[12] Docket No. 09-2035-01, Report on PacifiCorp's 2008 IRP, Division of Public Utilities, June 22, 2009, p. 33.
[13] PacifiCorp's 2013 IRP, Volume I, April 30, 2013, p. 222.
[14] Id.
[15] Docket No. 07-2035-01, Report and Order, February 7, 2008, p. 34.

In the end it is the Company's IRP. However, if the parties expend significant effort and time to work to ensure that the optimal portfolio is the end result, and in the end, the Company does not select that portfolio as the Preferred Portfolio, this begs the question of the efficacy of the entire IRP process, which the Division discusses in Appendix A.

<u>Replacing 208 MW of Washington situs wind with RECs</u>. Although this topic was broached previously in the Division's comments, it bears elaborating on in this section, as it ultimately weighs on the optimality of the Preferred Portfolio. Not only is the Company's decision to substitute case EG-2, C07(a) in place of case EG-2, C07 at the last minute unsupported by a least-cost, least-risk analysis, but it was not vetted through the IRP stakeholder process. This is another example of a manual change to the IRP process that the Company put in at the eleventh hour. The Company's original Preferred Portfolio (case EG2-C07) includes incremental eastside wind resources totally 202 MW in the first ten years and 858 MW in the 20-year period. After all the modeling was completed and a Preferred Portfolio was determined, the Company manually excluded 208 MW of Washington situs assigned wind resources in exchange for unbundled RECs to meet Washington's RPS compliance and tried to support it after the matter of the fact by comparing current unbundled REC prices (with no price future projections), to the cost of RPS resources selected by the model in the Preferred Portfolio. While current prices of unbundled RECs offer a low cost compliance option and this may in fact have saved ratepayers money in the short-term, the Company has not measured the expected costs of meeting RPS requirements through RECs or measured the risk of physical compliance.

The Company introduced in this IRP the RPS Scenario Maker, which the Company claims, optimizes the use of compliance flexibility mechanisms specific to each state, including the use of unbundled RECs and the use of banked RECs.[16] Again the Division wonders why more complexity is being added to the IRP process if, in fact, it is not being used, in the end.

Acknowledgement

[16] PacifiCorp's IRP Public Stakeholder Presentation, August 13, 2012, p. 37.

The Division cannot find that the Company's 2013 Preferred Portfolio is the optimal set of resources to meet the Company's long-term energy needs. The Company has not adhered to several of the Commission's directives and guidelines with respect to the IRP, and the final selection process is not quantitatively justified. In its IRP filing, the Company has requested that the Commission not only acknowledge the 2013 IRP, but fully support the IRP conclusions and the proposed Action Plan. The Division cannot fully support the IRP conclusions or determine that the Preferred Portfolio is the least-cost, least-risk portfolio. The Action Plan, likewise, should not be acknowledged because the conclusions leading to its development cannot be verified.

CONCLUSION

The Division appreciates the tremendous effort of PacifiCorp's IRP Team, the distribution of materials prior to the meetings, the responsiveness to data requests and questions, and the professionalism of the IRP staff in addressing concerns and suggestions from outside stakeholders. The Division commends the Company for its improvements to the public process and believes that the stakeholder participation in the 2013 IRP has been positively welcomed.

The Division has ongoing concerns about the Company's reliance on front office transactions to meet the next 10 year's capacity deficit and believes that DSM achievable amounts need to be closely monitored going forward. With respect to compliance, the Division believes that the Company's 2013 IRP reasonably complies with many of the Standards and Guidelines and the majority of the Commission's directives in its 2011 IRP Order. However, the Company's IRP is deficient in critical areas that cause concern whether the Preferred Portfolio is the optimal solution and whether the selection process of the Preferred Portfolio is analytically sound. The Division cannot fully support and verify the IRP conclusions and cannot recommend that the Commission acknowledge the IRP or the accompanying Action Plan. The Division recommends the Commission not acknowledge the 2013 IRP and Action Plan. Finally, the Division recommends process improvements that are contained in Appendix A attached to this memo and recommends that a constructive dialogue regarding revising the IRP process be ordered by the Commission.

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