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DIVISION COMMENTS ON PACIFICORP'S 2011 IRP

To: Public Service Commission

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Date: September 7, 2011

Re: Docket No. 11-2035-01, PacifiCorp's 2011 Integrated Resource Plan
In the Matter of the Acknowledgment of PacifiCorp's 2011 Integrated Resource Plan (filed on March 31, 2011) and PacifiCorp's 2011 IRP Addendum (filed on June 27, 2011).

RECOMMENDATION

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) acknowledge PacifiCorp's 2011 Integrated Resource Plan (IRP) and Action Plan. As explained below, the Division believes that the IRP adequately adheres to the Standards and Guidelines,[1] as well as directives from the Commission's April 1, 2010 IRP Order. However, 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.

[1] Docket No. 90-2035-01, Report and Order, June 18, 1992.

Finally, the Division suggests improvement measures for future IRPs and requests that the Commission considers and implements such measures.

ISSUE

This docket was opened on March 31, 2011, when PacifiCorp (Company) filed its 2011 Integrated Resource Plan. On April 6, 2011, the Commission convened a Scheduling Conference that resulted in the Commission's April 28, 2011, Request for Comments and Scheduling Order. The Company's 2011 IRP includes Volume I and Volume II (Appendices) and an IRP Addendum that was filed on June 27, 2011. As a result of the Commission's Request for Comments, the Division provides the following comments to the Commission. The Division's comments address conformance with the Commission's 2009 IRP Order, compliance with IRP guidelines, and the adequacy of the IRP.

COMPLIANCE WITH THE COMMISSION'S 2009 IRP ORDER[2]

The Commission directed or guided the Company to address the following items stemming from the 2008 IRP and 2008 IRP Update:

1. Portfolio Preference Scoring Approach and Analysis of Tradeoffs. Only portfolios from medium growth core cases were advanced to stochastic risk analysis. The Company should continue efforts to fully implement the three-step approach for developing the preferred portfolio: 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.

2. Planning Reserve and Energy Not Served (ENS). Perform a sensitivity case in its next IRP or IRP update wherein the ENS cost is flat and based on the Federal Energy

[2] Report and Order, Docket No. 09-2035-01, April 1, 2010.

Regulatory Commission price cap; identify a reasonable number of cases, including high and low load growth cases, to compare the costs and risks to customers, or identify a reasonable alternative method, e.g., a Loss of Load Probability (LOLP) study, for evaluating an appropriate planning reserve.

3. Reliance on Annual Wholesale Purchases. Include the costs of hedging in the IRP analysis of resources that rely on fuels subject to volatile prices; perform a sensitivity analysis to determine a hedging strategy that minimizes costs and risks for customers; include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely; identify whether customers or shareholders will be expected to bear the risks associated with the Company's reliance on the wholesale market; discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.

4. Consistent and Comparable Resource Evaluation. Discuss methods for improving the evaluation of non-traditional resources in an IRP public input meeting. At a minimum, this discussion should include ideas for improving the evaluation of distributed solar technologies, the evaluation of storage technologies, and a geothermal resource study to be filed with the Commission; the Company should omit from the core cases any resource for which the Company does not already have a signed final procurement contract or certificate of public convenience and necessity.

5. Load and Resource Balance. Convene a public input meeting or technical workgroup session to review the Company's approach to load forecast variation and the issue of load forecast error risk. the Company and interested parties should examine and consider all of the suggestions contained in this report; provide the Commission with a comprehensive stand-alone load forecast report when the forecast is updated.

6. Hydro Capacity Accounting. Address this issue in the Company's next IRP or IRP update and provide the results of its analysis. It may be useful to conduct sensitivity

analysis regarding this assumption to identify potential risks or shortcomings of the current methodology.

7. Wind Integration Costs. Conduct and file with the Commission a wind integration study and address the Division's concerns in the study in the next IRP or IRP update.

8. Resource Acquisition Paths and Decision Mechanism. Solicit and discuss further improvements to the IRP's resource acquisition path analysis and decision mechanism.

9. Business Plan Link. Maintain the IRP schedule and include the business plan reference cases in comparison to the other broadly defined cases; make the IRP information which is provided to the board in the December time frame available to parties upon request.

10. Public Process. Materials should be distributed one week prior to the public input meeting and a written report should be provided after each meeting to provide follow-up to issues or questions raised in the meeting.

11. IRP Filing Schedule. The IRP process and schedule must be maintained and allow adequate time for public input and review.

The Division finds upon its review of the 2011 IRP that the Company has reasonably addressed the above concerns. The Division provides additional comments below on the Company's load forecast and resource deficit, which is the essence of the entire IRP analytical framework, as well as the Company's hedging strategy.

Review of Load growth and Resource Deficit

Generally, the Company forecasts loads by state and then by class of service, i.e. by residential, commercial, and industrial (and a small "other," which is primarily street lighting). It uses different statistical methods and surveys that are customized to a particular state and customer. For large industrial customers, the forecasts are primarily based upon direct discussions with those customers about their expected electric needs by company representatives as well as information from various sources, including the media, about new large industrials coming into an area. The load forecasting process is lengthy and appears to be reasonably sophisticated. In the near term, i.e. one to three years out, the Company is able to modify its overall statistical forecasts with known load additions (or subtractions), such as the buildup of call and data centers in certain areas.

In making its final load forecast the Company assumed the savings from Class 2 DSM based upon the forecast Class 2 DSM in its preferred portfolio. Class 2 DSM includes the assumed replacement of less energy efficient equipment with more energy efficient equipment. For example, the replacement of incandescent light bulbs with fluorescent ones is a type of Class 2 DSM. The Company assumes that Class 2 DSM will be added at the rate of roughly 120 MW per year through 2020. Cumulatively, this is a sizable reduction in load amounting to the equivalent of about two base load plants by the end of 2020. This amount of Class 2 DSM seems aggressive compared to the 2008 IRP and 2008 IRP Update and the 2009 and 2010 Class 2 DSM actual amounts.[3] Clearly the amount of DSM has a material impact on load growth and consequently the need for Front Office Transactions (FOTs), that is, wholesale market purchases, and the construction of new base load plants. The amount of DSM resources acquired by the Company should be closely monitored for adherence to the forecast.

The Division analyzed the load growth forecasts prepared by the Company for the IRP. In general, the Company forecasted that its system peak load would grow at an average rate of about 2 percent per year. Peak load growth in the eastern service territory, which is serviced by PacifiCorp's retail distribution division, Rocky Mountain Power (RMP), is expected to grow at about 2.4 percent annually; the western territory is served by the Pacific Power division and is expected to grow at a rate of 1.4 percent, or roughly at 58 percent of the rate of the eastern territory. DPU Exhibit 1 sets forth total energy sales for the period 2000 through May 2011 based upon data compiled by the U.S. Energy Information Administration (EIA). These data

[3] 2009 and 2010 Class 2 DSM in Utah amounts to about 41 and 37 MW, respectively. In the 2011 IRP the amount of Utah Class 2 DSM additions is forecast to be 42 MW, which is similar to the 2009 total. More significantly in the 2011 IRP is that the total amount of Class 2 DSM assumed to be acquired by the Company over the 2011-2020 time frame amounts to about 1189 MW, which is a 27 percent increase over the 2008 IRP Update's amount of 935 MW. The 2008 IRP total Class 2 DSM was 916 MW over the same 2011-2020 period, or about 2 percent less than the 2008 IRP Update amount.

show that historically the growth rates of the Company have been about 1.5 percent annually since 2002, the first year containing a complete data set. This is somewhat short of 2 percent per year growth forecast in the 2011 IRP. This relatively short data set, however, is significantly influenced by the 2008-2009 recession, therefore based upon these data, a slightly higher growth rate might be expected if economic growth resumes for the next ten years or so.

DPU Exhibit 2 sets forth coincident peak data for the PacifiCorp system and for Utah for the period 1994 to 2010. The total period had a 1.70 percent average growth rate, whereas the more recent 2000 to 2010 period grew at about 1.55 percent annually. This longer data set is influenced by the 2008-2009 recession, but is also affected by earlier years of negative growth. These data also show a less than 2 percent per year growth rate. Slightly higher growth, approximating 2 percent per year, may be appropriate assuming the region comes out of the economic downturn it currently appears to be in. Otherwise, the 2 percent growth may be optimistic.

The Division believes that the overall results of this process are reasonable. The growth rates appear plausible, if perhaps a bit high based upon what is currently known. The Division next evaluated the overall reasonableness of the Company's load and resource balance forecasts. DPU Exhibit 3 is a simplified load and resource analysis covering the period 2011 to 2020. One simplifying assumption is that the somewhat random addition of miscellaneous resources such as solar, bio gas, combined heat and power, and coal turbine efficiency improvements are not significant to overall planning. Based upon the foregoing discussion the Division acknowledges the Company's load forecast out to 2020, its forecast of Class 1 and 2 DSM, and the Company's 13 percent planning reserve margin. The Company also sets forth its forecast of available FOTs on Table 6.18, page 151 of the 2011 IRP, which the Division also acknowledges.[4]

The Company's Action Plan contemplates purchasing up to 1,400 MW of FOTs per year over the 2011 to 2020 period. Fourteen hundred MW is approximately 89.5 percent of the 1,564 MW

[4] Of note is that there apparently is an additional 375 MW of FOTs capacity available from the Mid-Columbia hub at a premium price. This additional capacity is excluded from this analysis, as it appears to have been by the Company, and perhaps may be thought of as an "emergency backup."

estimated maximum FOTs available during the years 2013 and 2014. Based upon this 89.5 percent relationship, the Division assumed that 90 percent of the Company's forecast FOTs are available throughout the 2011 to 2020 time frame. This would appear to be a conservative assumption and provides some cushion regarding the available FOTs. Finally, it is assumed that resource surpluses in the west control area (west side) can be used to offset deficits in the east control area (east side); thus the acquisition of additional resources are managed to maintain an overall resource surplus including the forecast growth in DSM resources, FOTs and base load plant additions. The focus of the Division's analysis is on the base load plant additions, which appears to be a principal aspect of the planning process.

DPU Exhibit 3 calculates the east side, west side, and system load and resource balance based upon Company data and the above assumptions.[5] The 2011 IRP indicates that Wyoming wind QF resources amounting to about 143 MW of nameplate capacity are under construction. Likewise, the Lakeside 2 plant has been approved and is expected to be online in 2014. PacifiCorp is also in the process of releasing a new RFP to presumably acquire additional resources in the 2015 to 2017 time frame. These additional RFP resources are designated, for representation only, as "Currant Creek 2." In 2018 to 2020 the Company's IRP contemplates acquiring 800 MW (nameplate) of additional wind resources in Wyoming, which are at the end of a proposed transmission line. The transmission line and the wind resources go together. PacifiCorp also forecasts the acquisition of 475 MW in natural gas generation capacity on the east side in 2019. Based upon the IRP preferred portfolio resource additions, the total system remains in a resource surplus (including assumed DSM and the assumed available FOTs) through 2020. However, in 2013, there is potential for a "close call" with only a 7 MW surplus.[6]

DPU Exhibit 4 is the same as DPU Exhibit 3 except that the primary additions are made by "hand" by the Division. The 2012 Wyoming wind resources and Lakeside 2 are assumed to be given additions. The next probable addition is the "Currant Creek 2" acquisition, which is

[5] The resource balance deficits (surpluses) will be somewhat lower (higher) to the extent that the Company does add resources of solar, bio gas, combined heat and power, and improves coal turbine efficiency.

[6] This "close call" includes the 13 percent planning reserve margin and the possible addition of miscellaneous resources, suggesting that the Company would normally be expected to have perhaps over 1,000 MW of potential resources available to it over and above its load.

assumed to be acquired in 2017 on the basis of keeping the system balance in surplus, rather than in 2016 as in the IRP. After the "Currant Creek 2" acquisition, the Company's load and resource forecast necessarily becomes more speculative. Based upon current policy considerations and assuming no major breakthroughs in other technologies, major plant acquisitions will almost certainly be natural gas generation with possibly some additional wind. This thinking is reflected in the Company's IRP with the addition of 800 MW of nameplate wind (estimated to be about 280 MW net based upon a 35 percent assumed capacity factor) and 475 MW in natural gas generation in the 2018 to 2020 period. The current forecast suggests that an additional resource in the 2018 to 2020 time frame in the 500 MW range will be necessary to keep the system in surplus given the 13 percent planning reserve margin.

The purpose of this exercise is to test the reasonableness of the Company's IRP preferred portfolio with a minimum of assumptions and calculations. Given PacifiCorp's 13 percent planning reserve margin, the forecast 2 percent annual growth rate, the estimated availability of FOTs, and the assumed acquisition of DSM resources, along with the Company's currently existing resources and contracts, the acquisition of a significant resource "Currant Creek 2" becomes necessary by the year 2017, with the anticipation of an additional similarly sized resource in the 2018 to 2020 time frame. The "Currant Creek 2" resource could be acquired a year earlier, and more than 500 MW in additional resources following "Currant Creek 2" could be contemplated to reduce reliance on FOTs, whose availability probably becomes increasingly uncertain in the latter half of this decade. Therefore, without reference to natural gas prices, carbon tax amounts, system optimizer and PaR models, the Company's scenario for resource acquisition over the next ten years appears to be reasonable.

In preparing the above analyses, the Division noted a dearth of historical data in the IRP to which the various forecasts could be compared. The Division recommends that in future IRPs and IRP Updates the Company provides ten years of the most recent historical data on coincident peak loads and total megawatt hours, with jurisdiction and system totals. The Division also recommends that the Company provide a ten-year history of actual FOT purchases. The

Division also recommends that historical data on Class 1 and Class 2 DSM acquisitions be provided, by jurisdiction and system total, for at least the most recent five years.

HEDGING AND RELIANCE ON ANNUAL WHOLESALE PURCHASES

Appendix G of the IRP has been included to address part of item 3 - Reliance on Annual Wholesale Purchases in the previous IRP order. Market purchase transactions and issues relating to the Company's hedging strategy have been a concern to the Division and other parties in previous dockets. In the Commission's 2008 IRP Report and Order,[7] the Commission directed the Company to include additional information in order to gain more transparency and to work toward greater clarification and understanding surrounding these issues. Including these items in the IRP process will provide for a regular review of these issues. While additional information has been provided, the Division believes that this portion of the requirement has not been satisfied.

In order to understand why this has not been satisfied, it is important to look at the full context of the Commission order, which states:

> We are concerned with the Company's stated confidence in managing the risk associated with reliance on the market for a significant portion of its customers' power requirements, especially combined with its comfort with planning to a 12 percent planning reserve. These decisions appear to leave little room for forecast error related to prices and loads. Meanwhile, the Company is asking for an energy cost adjustment mechanism in a separate docket. In part, the Company there argues it cannot effectively manage the risks, even one year out, of the costs associated with unexpected fuel prices, wholesale electric prices, and loads. At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices. We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers.[8]

[7] Report and Order on PacifiCorp's 2008 IRP. Docket No. 09-2035-01, p. 18.
[8] Docket No. 09-2035-01, Report and Order, p. 29.

The Division has interpreted this order to mean that the Company should include the hedging cost, including market price adjustments, as part of the total fuel cost. It appears that the Commission is concerned with the total cost of the hedging program and would like to have a better understanding of how the Company attempts to manage the change in fuel prices.
The information relating to the cost of the hedging program included in appendix G looks at only the brokerage cost associated with these transactions. The company has not included the costs associated with the mark-to-market change in the price of the natural gas or the electric contracts. Figure G.1 in appendix G identifies the 2010 actual cost for hedging electricity as $113,484 and $627 as the hedging cost for natural gas. In DPU data request 2.1, the Division asked if the cost identified in Appendix G represents the cost of hedging. The Company responded with the following:

> Yes, the Company believes that including only the brokerage costs for natural gas and electricity satisfies the Commission Order. However, the Company considered including the cost of illiquidity in the form of the spread between the buyer's bid price and the seller's ask price, but this is difficult to quantify. Another potential cost would be collateral funding for credit clearing, but this is negligible due to the Company's very limited use of clearing. Not included as a cost is the gain or loss of hedges based on the difference between the contract price and the settlement price. This difference in prices is not known at the time of the IRP analysis.

It is unclear to the Division why the gains and losses have not been included or why the total fuel price for natural gas has not been recognized. Identifying the cost of hedging as only the brokerage cost is incorrect and misleading. For the Company to indicate that the market price of the contracts was not known at the time of the IRP analysis appears to be in conflict with testimony from Company witnesses in other proceedings.[9]

Issues relating to the current hedging program have been a concern to the Division and other parties for several years. This issue has been discussed in previous rate cases, the ECAM /EBA docket and has been the focus of several technical conferences. In the last general rate case, the

[9] Docket No. 10-035-124, Rebuttal Testimony of Stefan A. Bird, p. 15, line 332.

Company and other parties filed testimony relating to the cost of the current hedging program. The rebuttal testimony of Mr. Greg Duvall included an updated GRID report that identified $156.0 million in natural gas swap costs for the test year ending June 2012. This same report identified a reduction to net power cost of $66.0 million from electric swaps.[10] The stipulated settlement in the 2010 general rate case included a provision to review and modify the current hedging program due in part to the costs associated with the current strategy. The IRP order cited above states, "at a minimum" the costs of hedging should be identified. This would imply that the Company could include additional information to help the Commission better understand the current hedging strategy and all the related costs.

The second portion of the requirement states that the Company should perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers. While the analysis looks at volatility, it does not address how the current strategy minimizes cost. In data request 2.3 the Division asked the Company to explain how the current strategy minimizes cost. The Company responded with the following statement:

> The current strategy reduces net power cost volatility risk to customers. Cost minimization measured by hedge gains and losses could only occur if the Company knew the settlement price at the time the hedge was contracted and this is not possible. As noted in Appendix G, and demonstrated by the Company's sample portfolio simulations, the expected value of any hedging strategy is the same prior to execution, and therefore all hedging strategies result in portfolios with the same expected net power cost outcome.

The sensitivity analysis included five different portfolio scenarios. The intent of this analysis is to look at the aggregate "volatility" of the combined power and natural gas portfolio. Scenario one is used as the reference portfolio and assumes a 500 average MW long power position and a short 100,000 MMBtu/day natural gas position. This assumes that the Company will have excess power available and that these conditions are representative of the current conditions. In response to DPU data request 2.4 and 2.5, the Company indicated that these are not the actual open positions and comparisons to historical or forecast positions is commercially sensitive and

[10] Docket No. 10-035-124, Rebuttal Testimony of Greg Duvall, UT GRC 2011 Rebuttal Gold NPC Study 2011 06 22.

highly confidential. Each of the subsequent alternative scenarios look at the volatility impact compared only to the reference portfolio. Portfolio two adds 25% to both the gas and the electric positions (625 MW and 125,000 MMBtu). Portfolio three reduces both gas and electric by 25% (375 MW and 75,000 MMBtu). Portfolio four assumes no long power position and a short gas position (0 MW and 100,000 MMBtu). Portfolio five assumes a long power position and no short gas position (500 MW and 0 MMBtu). All of the alternative portfolio positions look at the combined gas and electric position, and four of the five portfolios assume that the Company will have excess power available. There is no analysis of how the current program controls or minimizes cost. Appendix H provides an evaluation of available resources to support the reliance on market purchases. This Appendix satisfies the requirement identified in the 2008 IRP report and order. The WECC report cited indicates that additional resources will be needed in 2019.[11]

ADEQUACY OF THE 2011 IRP

The Division reviewed 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. The Division, as well as other parties, has provided informal comments to the Company throughout the cycle of the IRP in the form of questions, verbal comments, and written comments. According to the Guidelines, this is the opportunity to provide formal comments to the Commission on the adequacy of the IRP.[12]

In the past the Division has commented extensively on the IRP process itself and has worked to bring about critical improvements to the process.[13] The Division notes that the Company has worked to improve the process by providing meeting materials one week in advance, by answering informal queries, and by trying to make the plan more transparent. The Company has

[11] Appendix H – Western Resource Adequacy Evaluation, p. 171.
[12] Report and Order on Standards and Guidelines, Docket No. 90-2035-01, June 18, 1992.
[13] Docket No. 09-2035-01, DPU Report and Recommendations on PacifiCorp's 2008 Integrated Resource Plan, June 18, 2009.

offered opportunities throughout the public stakeholder process for parties to comment on a given topic; however, barring a full-time consultant dedicated to IRP only, adequate time was not allowed to provide in-depth comment. The Division also recognizes that the Company has limited staff working on the IRP.

In its 2009 IRP comments, the Division requested that early in the process the IRP model would be made available in order for parties to verify assumptions and results. However, in the end and after the Company's extensive efforts to obtain permission from its vendor, the result was yet another Power Point presentation that only outlined how the model worked. This result was significantly short of expectations. Therefore, in response to the Commission's request for comments on the adequacy of the plan, the Division can only comment on what the Company has presented and cannot fully verify the adequacy of the plan.

As presented throughout the public stakeholder meetings and upon the Division's review of the IRP documents, the Company has satisfied the Commission's directives from the 1990 Order. However, the Division cannot either confirm or deny that the plan results in a preferred portfolio that is the least-cost, least risk portfolio.

The Division recommends that the IRP process itself be revisited, as it has been over ten years since the IRP procedures were developed. The Division recognizes that, with each subsequent IRP Order, the Commission has ordered the Company to conduct other studies or to submit other requirements (many of which have been a result of the Division's request). However, in the end, the process has become even more complex and burdensome to the Company, to the Division, and perhaps to others--making it difficult to adequately participate and for the Company to fully implement stakeholder suggestions.

The Division believes that there may be a more efficient and effective methodology to arrive at a verifiable least cost, least risk resource plan. The Division recommends that a cursory analysis of other state and utility resource plans be conducted and considered.

CONCLUSION

The Division appreciates the effort of PacifiCorp's IRP Team, the preparation for the meetings, the responsiveness to data requests and questions, and the professionalism of the IRP staff in addressing concerns and suggestions from outside stakeholders.

Although the Division does not believe that the IRP compliance requirement with respect to hedging was met, the Division finds that the 2011 IRP reasonably meets the Commission's other requirements and should be acknowledged. In lieu of the Division's own independent analysis of the load and resource deficit, it appears that the outcome of the Company's preferred portfolio is reasonable. However, as stated previously, absent several input assumptions and access to the model itself, there is not enough information to determine if the resulting preferred portfolio is the least-cost, least risk outcome. Finally, the Division requests that a more effective and efficient process be considered for future IRPs to arrive at the least-cost, least-risk portfolio that can be verified by interested parties.

CC Dave Taylor, Rocky Mountain Power
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