- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan	)))))	DOCKET NO. 09-2035-01 REPORT AND ORDER

ISSUED: April 1, 2010

SHORT TITLE

PacifiCorp 2008 Integrated Resource Plan

SYNOPSIS

The Commission acknowledges Integrated Resource Plan 2008 and concludes it generally adheres to the Standards and Guidelines for PacifiCorp. The Commission provides guidance herein to assist in the development of the next IRP.

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By the Commission:

I. INTRODUCTION

In March 2009, PacifiCorp, doing business in Utah as Rocky Mountain Power ("PacifiCorp" or "Company"), was expected to file its biennial Integrated Resource Plan ("IRP"). On March 19, 2009, the Company filed a notice with the Commission indicating it was changing its filing date to May 31, 2009. In response to the recommendations of the Utah Division of Public Utilities ("Division") and the Committee of Consumer Services (now the Office of Consumer Services or "Office"), on April 7, 2009, the Commission issued an order and notice of scheduling conference directing the Company to file a draft of its IRP on April 8, 2009.

On April 8, 2009, the Company filed a draft of its tenth Integrated Resource Plan pursuant to the IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01, *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Report and Order issued June 18, 1992. Pursuant to the Commission's April 27, 2009, request for comments and scheduling order, the Company filed its wind integration study (Appendix F), its complete, final IRP, and its proposed schedule and rationale for the filing dates of future IRPs. The Company requested the Commission acknowledge the IRP in accordance with its rules and fully support the IRP conclusions, including the proposed action plan.

Summary of the 2008 Integrated Resource Plan Results

Entitled "2008 Integrated Resource Plan" ("IRP 2008"), the report and associated appendices present PacifiCorp's plan to supply and manage growing demand for electricity in its six-state service territory over the next 20 years. The report identifies, as its least cost plan, investment in a portfolio of power plants and power purchases, coupled with customer efficiency programs and direct-control load management. The type, timing and magnitude of resource additions are noted and an action plan is provided.

Based on its assumptions of existing generation capacity, generation plant life, length of existing purchase power contracts, transmission transfer capability, and its November 2008 load growth forecast, PacifiCorp identifies a deficiency between existing resources and peak system requirements plus a 15 percent planning reserve[1] of 277 megawatts beginning in 2010. This deficit grows to 2,261 megawatts in 2012 and to 3,895 megawatts in 2018.[2] Assuming a 12 percent planning reserve, a deficiency of 498 megawatts begins in 2011. This deficiency grows to 1,936 megawatts in 2012 and to 3,528 megawatts in 2018.[3] PacifiCorp identifies the resource investment schedule for Portfolio 5B_CCCT_Wet modified by a manually developed wind acquisition schedule ("Modified 5B"), coupled with its transmission facilities investment schedule, as its least cost plan or "Preferred Portfolio," to meet this deficiency.[4]

PacifiCorp bases its selection of Modified 5B on its analysis of the present value of future revenue requirement ("PVRR"), load growth uncertainty, fuel and market price volatility, firm transmission transfer capability, hydro variability, customer rate impacts, expectations of potential costs associated with meeting existing and potential environmental

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[1] Planning reserve also provides for operating reserve; IRP 2008, Chapter 5, pages 89-90.

[2] IRP 2008, Chapter 5, page 92, Table 5.19.

[3] IRP 2008, Chapter 5, page 91, Table 5.18.

[4] The investment schedule for the Company's Preferred Portfolio is provided in IRP 2008, Chapter 8, page 245, Table 8.44.

regulations, lead time required for plant construction or bidding, fuel source diversity, capital cost requirements, ability to meet demand, production cost variability, procurement and construction risks and manual changes to the wind resource acquisition schedule.

To serve system-wide peak hour demand over the next ten years, cumulative supply additions and direct-control load management or energy efficiency programs in the Preferred Portfolio range from 332 megawatts in 2009 to 4,643 megawatts in 2018.[5] By 2018, this consists of 2,723 megawatts of intermittent, intermediate and base load power plant (including one long-term firm unspecified power purchase in 2012); 50 to 1,382 megawatts in annual unspecified power purchases; and 1,111 megawatts of direct-control load management or utility energy efficiency programs. The proportion of additional resources are 59 percent long-term generation plant or power purchase (31 percent renewable energy, 18 percent gas, 4 percent unspecified long-term power purchase, 4 percent coal, 2 percent combined heat and power),[6] 24 percent direct-control load management or energy efficiency utility programs, and 17 percent unspecified annual power purchases.

Summary of IRP 2008 Modeling Process

PacifiCorp's IRP modeling effort consists of multiple phases. The process begins with the identification of general assumptions and price inputs and the definition of cases consisting of alternative sets of assumptions. The Company developed 29 core cases based on

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[5] The total of 4,643 megawatts includes the average annual amount of 809 megawatts of unspecified power purchases rather than the cumulative amount of annual purchases over the ten year period, which is 8,087 megawatts.

[6] PacifiCorp notes it may either build the resource or acquire it through a long-term firm power purchase agreement.

variations of four key variables: Natural gas price, wholesale electricity price, retail load growth, and carbon dioxide ("CO2") tax. The CO2 tax assumptions range from $0 per ton to $100 per ton;[7] natural gas price in 2010 ranges from $5.83 per million btu to $18.06 per million btu; wholesale electricity price in 2010 ranges from approximately $50 per megawatt hour to approximately $130 per megawatt hour; load growth ranges from 1 percentage point average annual growth rate below the medium forecast to 1 percentage point average annual growth rate above the medium forecast. PacifiCorp also developed 17 sensitivity cases based on variations of CO2 compliance strategies, clean base-load technology availability, planning reserve, and inclusion of price-responsive demand-side management programs as resource options. The Company then added two "reference" cases reflecting its 2009 business plan resources for 2009 through 2018, resulting in a total of 19 sensitivity cases.

To develop optimal portfolios of resources for each of the 48 defined cases, the Company used a computer modeling program, System Optimizer, which generates an optimized investment plan and associated real-levelized PVRR for 2009 through 2028. The System Optimizer operates by minimizing the annual operating costs of existing resources subject to system load balance, reliability and other constraints. Over the 20-year period, it also optimizes resource additions subject to resource investment and capacity constraints, based on monthly peak loads plus a planning reserve for each load area represented in the model.

[7] These are 2008 dollars; all CO2 taxes have an assumed 2013 implementation date and increase at PacifiCorp's assumed inflation rate.

The Company then performs a Monte Carlo production cost simulation of each optimal portfolio using another computer model, Planning and Risk ("PaR"), in its stochastic mode. The PaR simulation incorporates stochastic risk in its production cost estimates by using a stochastic model and Monte Carlo random sampling of five stochastic variables: Loads, natural gas price, wholesale electricity price, hydro energy availability, and thermal unit availability for new resources. In IRP 2008, the Company limited this process to 21 of the 48 defined cases. The 21 cases are the core cases defined with the medium load growth assumption plus the Company's two business plan reference cases. Three stochastic simulations were executed for three CO2 tax levels: $0, $45 and $100 per ton. All simulations used the Company's October 2008 natural gas and wholesale electricity price forecasts, (gas price ranges from $7.83 to $11.57 per million btu in 2010; electricity price ranges from approximately $60 to $80 per megawatt hour in 2010).

The PaR simulations measure the performance of each optimal portfolio with respect to its cost, risk and reliability. The cost measurements PacifiCorp uses to compare optimal portfolios are: Mean PVRR; risk-adjusted mean PVRR; minimum PVRR cost exposure under CO2 tax outcomes; customer rate impact; and capital costs. The risk measurements it uses are: Upper-tail mean PVRR; 95th percentile PVRR; and production cost standard deviation. The supply reliability measurements it uses are: Average annual energy not served ("ENS"); upper-tail ENS; and loss of load probability ("LOLP"). In addition to these stochastic measures, PacifiCorp reports fuel source diversity statistics and the emission footprint of each portfolio.

To identify its top performing portfolio, PacifiCorp developed a weighted scoring scheme which combines selected portfolio performance measures into an overall composite score. The Company gave 45 percent weight to risk-adjusted PVRR,[8] 20 percent weight to customer rate impact, 15 percent weight to CO2 cost exposure, 5 percent weight each to capital cost, production cost standard deviation, average annual ENS and average annual probability of ENS events for July exceeding 25 gigawatt hours. PacifiCorp applied this scoring scheme to a subset of cases in order to maintain cost comparability with respect to the amount of resources required. The top three portfolios were selected as preferred portfolio candidates.

The Company then subjected the top three ranking portfolios to scenario risk assessment [risks associated with uncertainty rather than historical variability] by subjecting the three preferred portfolio candidates to alternative future assumptions regarding natural gas and wholesale electric price and CO2 tax level, which are PacifiCorp's main sources of stated portfolio risk. PacifiCorp again used the System Optimizer to determine the PVRRs for the three portfolios using the sets of assumptions included in 10 of what it characterizes as core cases representing a range of CO2 and natural gas and wholesale electricity price assumptions. PacifiCorp reports the mean and standard deviation for each portfolio's PVRR, ranks each portfolio and computes the rank sum as an overall performance indicator.

On the basis of the portfolio preference scores, and further consideration of resource risks and fuel diversity, PacifiCorp selects the preferred portfolio from the top-

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[8] Risk-adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95th percentile PVRR, with the latter term representing a cost premium reflecting the tail risk for the portfolio. Source: IRP 2008, Chapter 8, page 196.

performing portfolios. PacifiCorp then conducts a next best alternative analysis that applies a number of procurement risk scenarios to determine optimal portfolios in the event of unplanned circumstances. The focus of this analysis is on firm planned and new resources in the preferred portfolio.

Based on this planned analytical approach, PacifiCorp would have identified the portfolio of resources selected by System Optimizer in Case 5 as its preferred portfolio. However, the Company had included in all of its 48 cases, the assumption that the Lake Side 2 power plant was an existing resource which would be in service in 2012. When the Company decided to terminate this acquisition, it conducted additional portfolio analysis to determine a revised preferred portfolio based on this decision and the inclusion of new transmission and market assumptions which it had used to support the decision to terminate the 2012 Lake Side 2 contract. To this end, the Company created 10 additional cases.

In two of the ten cases, the Company used the same set of input assumptions as Case 5 and removed Lake Side 2 in 2012. In one of these two cases, PacifiCorp included a combined cycle combustion turbine ("CCCT") using wet cooling technology as a "fixed" or existing resource in 2014 located at the Lake Side site and in the other included a CCCT using dry cooling technology as an existing resource in 2014 located at the Currant Creek site.[9] PacifiCorp included the CCCT as an existing resource in these two cases to ensure some portfolios would include this technology. This is because the System Optimizer does not

[9] The term "fixed" means the Company required the resource to be added to the model run rather than allowing the model to select the resource as part of the computer optimization process.

account for resource optionality and reserve holding value and therefore tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins.[10] For the remaining eight cases, the Company used the top eight portfolios which were generally based on the portfolio weighted performance scores, removed the Lake Side 2 plant, and used the System Optimizer to identify new portfolios of resources for those cases.[11]

Stochastic production cost simulations with multiple CO2 tax levels were also performed for all 10 portfolios and the Company developed a full set of performance measures for each case and ranked them using the same preference scoring scheme applied to the original 21 portfolios. Based on its analysis of these 10 cases, known as the B series cases, the Company selects Case 5 with the wet-cooled CCCT located at Lake Side in 2014. Due to concerns with timing of wind resources shown to be optimal in this portfolio, PacifiCorp adjusted the timing of the wind resource procurement. PacifiCorp argues these adjustments are necessary to "emulate a long-term procurement program that ideally accounts for rate stability/financial impacts, anticipated demand for construction and equipment resources, flexibility to respond to changing market and regulatory conditions, construction management requirements, and location-specific considerations not factored into the IRP models."[12] The effect of this change is to accelerate and spread wind resource online dates over the planning horizon, and to locate 200 more megawatts

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[10] Resource optionality and reserve holding value are captured through the stochastic production cost modeling.

[11] There appears to be a typographical error in IRP 2008, Chapter 8 on page 235 as the preference scores are not in Table 8.36 as referenced. Also, there appears to be a substitution of case 47 for the higher ranked case 11 in the B series analyses.

[12] IRP 2008, Chapter 8, page 240.

of wind resource in the eastern side of the utility system. This planned wind acquisition schedule coupled with the other resources identified in Case 5 with the wet-cooled CCCT at Lake Side in 2014, is the Company's Preferred Portfolio and the subject of the implementation steps outlined in its IRP 2008 action plan.

Request for Comments

On April 27, 2009, the Commission requested comments from interested parties on IRP 2008 by June 18, 2009, and reply comments by July 2, 2009.

Under the Guidelines, we consider whether to "acknowledge" IRP 2008. Acknowledgment of an IRP means it complies with the regulatory requirements of the planning process, but conveys no sense of regulatory approval of specific Company resource acquisition decisions. Instead, integrated resource planning is an open, public process through which all relevant supply-side and demand-side resources, and the factors influencing choice among them, are investigated in the search for the optimal set of resources to meet current and future electric service needs at the lowest total cost to the utility and its customers, in a manner consistent with the long-run public interest, given the expected combination of costs, risks and uncertainty. Clearly, PacifiCorp management retains responsibility for its decisions.

Utah Code §54-17-302 now requires PacifiCorp to obtain Commission approval of any significant energy resource decision before it constructs or enters into a binding agreement to acquire the resource. Further, Utah Code §54-17-301 requires the Company to file any action plan developed as part of its IRP to enable the Commission to review and provide guidance to the Company. The resource solicitation and acquisition decision approval processes are separate from the IRP acknowledgment process. Therefore, while we may acknowledge the IRP, and may provide guidance on the IRP action plan, any approval of the solicitation and acquisition of specific resources for the implementation of that action plan will be conducted in separate approval processes required under Utah Code §54-17-201 and §54-17-302.

II. PARTIES' COMMENTS

On June 18, 2009, the following parties filed written comments and recommendations on IRP 2008 and on the Company's proposed schedule for filing future IRPs: The Division, Office, Interwest Energy Alliance ("Interwest"), Utah Association of Energy Users ("UAE"), Utah Clean Energy ("UCE"), and Western Resource Advocates ("WRA"). On June 22, 2009, the Division filed errata to its comments. On July 6, 2009, PacifiCorp filed a reply to these parties' comments and on July 9, 2009, filed a corrected version of its reply comments. On August 18, 2009, the Company filed errata to the 2008 IRP.

The Division, Office, UAE, UCE, WRA and Interwest do not recommend acknowledgment of the IRP. The Division, Office, and WRA argue IRP 2008 does not sufficiently adhere to the Commission's Guidelines and should not be acknowledged. UCE recommends a partial acknowledgment if possible. Interwest recommends the Commission either not acknowledge the 2008 IRP or condition acknowledgment upon the requirement that PacifiCorp rely on the most cost-effective portfolio. The Company responds to these parties' comments, and argues the Commission should find the IRP to be in compliance with the Commission's Guidelines and grant acknowledgment. The Company recommends the

Commission acknowledge the plan and provide specific guidance regarding any additional analysis or future study deemed to be necessary.

The comments filed provide varying degrees of support for IRP 2008. Parties comment on the optimality of the Preferred Portfolio, load and resource balance, wind integration cost, link to strategic business plan, the decision mechanism for resource acquisition paths, and the IRP public process and procedural issues. We recapitulate the salient points of these comments below and provide guidance to the Company on issues raised.

A. Optimality of the Company's Preferred Portfolio

Our Guidelines define integrated resource planning as "...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 interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."[13]

The Division does not find a direct analytical link in IRP 2008 to conclude the Company's Preferred Portfolio is the optimal plan. The Division cites a number of inadequacies within the IRP that contribute to this conclusion, including the following: Insufficient analysis of planning reserve margins; the inability of the IRP to inform the business plan; a random weighting factor scheme performed on the top-performing portfolios; hand-built cases with the removal of the Lake Side 2 natural gas combined cycle power plant; advanced and emerging

[13] Guidelines, page 39.

technologies which were not considered at their full potential due to up-front cost-weighting of potential resources; and lack of transparency and ability of parties to participate fully in the IRP process.

The Office states the Company fails to demonstrate its Preferred Portfolio is either optimal or ensures adequate resources for ongoing reliable service and therefore may not result in a low-cost, low-risk and reliable set of resources for residential and small business customers. The Office argues several of the assumptions and modeling decisions by the Company are likely to understate the resource needs of the Company in the near term.

The Office cites the following concerns with the Company's assumptions: The 12 percent planning margin and treatment of energy not served does not demonstrate planning to an appropriate resource level; significant reliance on the market without providing adequate evidence of sufficient market liquidity to guarantee supply; potential overstatement of the capacity contribution from market contributions; the peak forecast may not identify the appropriate load level for which to plan; failure to consider multiple scenarios for the peak forecast; inadequate range of economic conditions and range of weather scenarios to examine how changes in load conditions impact the portfolios and provide contingency plans to cover these types of variances; modeling restrictions placed on geothermal resources and selection of wind resources; the hard fixing of specific natural gas resources; and the certainty assumed in the acquisition of a 201 megawatt long-term firm contract.

The Office contends the role of the IRP 2008 may have been fulfilled if its value is in the interaction between the Company and parties and the opportunity for guidance from the

Commission. However, the Office is concerned the resources spent by interested parties in evaluating and commenting on the IRP are neither resulting in a useful plan nor any consequences to the Company. At a minimum, the Office believes the Commission should provide guidance to the Company that operating without an acknowledged IRP puts the Company at risk for recovery of future costs due to risks for which the Company did not adequately plan. If the IRP 2008 is not acknowledged, the Office recommends additional analysis and comments for the purpose of acknowledgment.

UAE is not convinced the Commission can determine the IRP process has produced the least-cost, least-risk resource portfolio option. UAE argues the Company's Preferred Portfolio continues to rely heavily on market purchases through 2013 before new base load generation can be installed. Further, UAE questions the Company's portfolio preference scoring approach.

WRA, UCE and Interwest argue the Company's Preferred Portfolio is not the optimal set of resources given the expected combination of costs, risks, and uncertainty. These parties contend Portfolio 8 outperforms Portfolio 5 on most performance measures and best prepares the Company and customers for carbon regulation and fuel price risk.

We next review the key concerns parties have with the optimality of the Company's Preferred Portfolio and provide guidance for future IRPs.

1. Portfolio Preference Scoring Approach and Analysis of Tradeoffs

All parties have concerns with the Company's portfolio preference scoring approach which UAE argues was presented late in the process and was not thoroughly vetted in public meetings. The Division argues the hand-built weighting schemes for eight performance measures is insufficiently explained or inadequate analysis is provided regarding its derivation. The Division recommends the Company discuss the exact weight percentages it used and explain why cost and risk measures are not equally weighted. At a minimum, the Company should present the results of a wider variety of selection criteria and weights in order to demonstrate how portfolios perform under different valuation scenarios.

UAE notes shifting weight from rate impacts and capital costs to CO2 cost exposure and risk-adjusted PVRR switches the relative rankings of the top two ranked portfolios, Cases 8 and 5. The Company selects Case 5 over Case 8 because the "disadvantage for case 8 is the amount of wind investment in the first 10 years, which reaches 2,600 MW. The average annual capacity added for 2012 through 2018 exceeds 300 MW, which is a concern from procurement, rate impact, construction project management, and operational perspectives." UAE questions why these concerns are not captured in the cost and risk metrics or why they should be the rationale for selecting Case 5 over Case 8.

UAE also questions the metrics selected to receive a weighting. Fuel source diversity does not receive a weighting presumably because the risk lowering benefits are captured in the stochastic risk measurements which vary fuel costs. Conversely, CO2 cost exposure receives a large weighting even though part of this risk should be captured by the production cost standard deviation. Thus, UAE concludes there is the potential for both undercounting and double counting for certain risks and costs, and recommends this approach receive additional attention.

The Office also suggests the Company's portfolio weighting scheme needs more attention and notes it is very sensitive to alternative weighting decisions and the Company provides little support for using the weighting structure it proposes. With a slight change to the weighting factors, Portfolios 8 and 5 reverse position in the ranking. If weighting was changed in the assessment of the B series cases, from which the Preferred Portfolio was selected, a similar outcome may result. The Office argues the unsupported portfolio preference scoring calls into question the selection of 5B CCCT Wet as the Preferred Portfolio and indicates wind resources may be understated as the amount of wind resources is the primary difference between Cases 5 and 8.

In the initial portfolios studied, WRA, UCE and Interwest note Portfolio 8 outperforms Portfolio 5 with respect to: Expected cost; risk adjusted PVRR; portfolio cost exposure for CO2; upper tail risk; cost/risk tradeoff at $45 and $100 per ton of CO2, and average across all CO2 tax levels; energy not served; emissions footprints for CO2, sulphur dioxide, nitrogen oxide, and mercury; and the alternative weighted measure of overall performance as suggested by public input participants. Further, in all but one of the cost/risk scatter plots provided, Portfolio 8 was on the efficient frontier. WRA states Portfolio 5 outperforms Portfolio 8 on the following four performance measures: Capital cost, customer rate impact, loss of load probability, and in the weighted performance measure the Company proposed. WRA, UCE and Interwest all point out that Portfolio 5 was developed using the low June 2008 natural gas projections which are the lowest natural gas price projections analyzed in the IRP. Whereas Portfolio 5 performed best in low gas/low CO2 tax scenarios and performed worst in high gas price and high CO2 tax scenarios, Portfolio 8 performed best in medium/high gas price and medium/high CO2 tax cases but performed worst in low gas/low CO2 cases. Therefore, these parties conclude Portfolio 8 would best protect the Company and its customers from its two greatest risks, fuel prices and carbon regulation.

The Company states the purpose of the measure importance weights and portfolio preference scores is to explicitly show how the Company ranks portfolios by combining a diverse set of performance evaluation measures. This is intended to address past concerns regarding the transparency with which the Company makes use of the various comparative portfolio performance measures and selects its Preferred Portfolio. The Company argues it sought and acted upon recommendations regarding the portfolio preference scoring approach but that the weights applied reflect the Company's subjective view of the most relevant and important measures for its integrated resource planning process. The Company recognizes different weighting schemes can change portfolio ranking results and provides one alternative in the IRP. However, the Company maintains it is the "Company's prerogative as the developer and owner of the IRP to apply a single weighting scheme that best represents its resource planning objectives."[14]

The Company is interested in the Commission's perspective on the use of a portfolio preference scoring approach, the weights applied by the Company, and suggestions for improvement. However, the Company argues the purpose of the measure-weighting scheme is to reflect the Company's own planning principles and priorities at the time the IRP is being

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[14] PacifiCorp's July 9, 2009, Response to Utah Party Comments, page 8.

produced rather than to reflect the resource policies of individual stakeholders or any policy consensus among multiple stakeholders. The Company contends if it deviates from this point of view, then the IRP is a considerably less effective planning tool for the Company.

Regarding UAE's concerns as to why fuel source diversity has not been given a performance measure weight and why CO2 cost exposure receives a large weight even though part of this risk is captured in the production cost standard deviation, the Company explains it found it difficult to quantify fuel source diversity in a meaningful way for portfolio ranking purposes and therefore decided to treat it subjectively, outside the scoring system. Regarding the "double counting" of CO2 risk, the Company explains the CO2 cost exposure measure is intended to capture the value of avoiding an extreme cost outcome whereas production cost standard deviation is intended to capture the value of avoiding cost volatility, and therefore there is independent value to including both in the preference scoring.

Several parties argue Portfolio 8 is superior to the Company's Preferred Portfolio. The Company responds by noting the two portfolios are very similar with respect to the portfolio preference scores of the original 21 portfolios analyzed. The Company's main concern with Case 8 is the large incremental capital cost impact of the additional wind, as well as the Company's ability to acquire and integrate this amount of wind on a sustained basis. This amount of wind resource would require, on average, over 300 megawatts per year from 2012 through 2018. For the final 10 portfolios examined, the three variants using Case 5 input assumptions outperformed Case 8 based on the Company's preference scores.

Guidance on Portfolio Preference Scoring and Analysis of Tradeoffs

We commend the Company for the progress it made in IRP 2008 toward greater transparency in explaining how its Preferred Portfolio is optimal considering risks and, to some degree, uncertainty. We recognize parties disagree regarding which risks and other considerations should be weighed more heavily and we appreciate the input parties provide regarding different views of the long-run public interest. Indeed, parties are able to debate the Company’s conclusions and, using the information generated in the IRP analytical process, offer informed views. This is a positive step when compared with the last IRP wherein parties were unable to determine how the Company came to its conclusions and could not thread through the series of portfolios created. This healthy discussion of key issues of expected costs, risks, and reliability is precisely one value intended in the IRP process.

We recognize the Preferred Portfolio represents the Company’s view. The Company now has ample input regarding parties’ concerns with this view and with its consistency with alternative views of the long-run public interest. Regarding the portfolio weighting approach, we find it produces transparency with respect to understanding the Company’s view of the long-run public interest. However, the weighting approach cannot replace the primary metrics and analysis which the Company provides demonstrating the tradeoffs of costs, risks and uncertainty of alternative portfolios. With this information, the Company, and any party, can explain to the Commission how different weightings of the expected costs and risks of alternative resource acquisition paths serve the public interest. Such information will be valuable in rate-setting or other appropriate proceedings.

We appreciate the Company's efforts to consider the three-step approach for developing its preferred portfolio we outlined in the last IRP, namely: 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. However, we note only portfolios from medium load growth core cases are advanced to stochastic analysis addressing risk and scenario analysis addressing uncertainty. This approach precludes most of the portfolios which were generated from alternative load growth and sensitivity scenarios from further evaluation. Evaluation of these additional cases may prove valuable in understanding the risk-mitigating benefits of alternative resources and prove instructive when the world unfolds in unexpected ways. We encourage the Company to continue efforts to fully implement this three stage approach.

2. Planning Reserve and Energy Not Served

The Division argues the Company did not comply with the Commission's directive to continue to study tradeoffs in planning to different planning reserve targets. The Division argues the Company's approach, a comparative analysis of 12 and 15 percent planning reserve levels, relies on the arbitrary selection of ENS tiers and costs, and studies just three cases. The Division states it appears the Company has decided to only plan to a 12 percent reserve without explanation of this conclusion.

The Office states the Company's analysis of a 12 versus 15 percent planning reserve involves the comparison of cases using common CO_2 tax assumptions. The Office points to a comparison of Case 8 with a 12 percent planning reserve and Case 41 with a 15 percent planning reserve which shows an increase in the PVRR of about $321 million. The Company provides a cost-risk tradeoff for these two cases which the Office states shows a cost premium of $659 per megawatt hour for the higher planning reserve. The Office states the Company concludes from this analysis that "... from a stochastic modeling perspective, it is not cost-effective to invest in incremental generating capacity for reserves given that the cost premium for such investment is above the assumed ENS cost."[15]

The Office argues this conclusion is based on the Company's decision in IRP 2008 to introduce a declining block rate for the cost of ENS. In past IRP's the Company assumed a flat rate, valued at the Federal Energy Regulatory Commission price cap, as a proxy for buying emergency power. In IRP 2008, the Company values the cost of ENS using a declining block cost structure of $400 per megawatt hour for the first 50 gigawatt hours per year, $200 per megawatt hour for the next 100 gigawatt hours per year and $100 per megawatt hour for all amounts over 150 gigawatt hours per year. The Office questions the Company's apparent preference for rolling blackouts rather than spending $659 per megawatt hour to serve the energy requirements.

The Office suggests the Company compare the costs and risk profiles of several portfolios with identical input assumptions except for the planning reserve assumption, including

[15] IRP 2008, Chapter 8, page 221.

appropriate costs assigned to ENS, and base its planning reserve requirement decision on this information. At a minimum, the Company should provide sensitivity analysis using a flat ENS cost at different cost levels so it could compare the results of this more standard industry approach with the Company's declining block approach. Alternatively, the Company could undertake an LOLP and rely on the industry-wide criteria to plan the utility system such that it will experience no more than 1 day of outages in 10 years or 2.4 hours per year.

UAE believes the Company's cost-risk tradeoff analysis adequately supports the Company's use of a 12 percent planning reserve. UAE contends the planning reserve should be used as a tool to evaluate investment timing rather than serve as a measure of actual system reserves. However, UAE notes the Company's analysis does not capture all potential reliability issues associated with different planning margins.

The Company disagrees with the Division and Office that its planning reserve analysis is inadequate and that its treatment of ENS is arbitrary. The Company argues it conducted a stochastic cost analysis of portfolios with different planning reserve margins as requested by the Commission. The Company argues it clearly identified the costs associated with selecting a 12 percent planning reserve versus a 15 percent reserve given the three CO2 cost levels included in the study and found no basis to change the reserve margin assumption for the IRP. The Company maintains the economic recession and its impact on load growth also supports its view that moving to a higher planning reserve is unwarranted at this time.

The Company introduced a measure to identify the opportunity cost of reducing each megawatt hour of ENS for given portfolios developed with the 12 and 15 percent planning reserve margins. The Company argues its treatment of ENS in this IRP, i.e., use of a 3-tiered pricing structure, is not arbitrary because it accounts for how the Company would respond in practice to persistent and large ENS levels over a long planning horizon. The Company argues the new approach is superior to using a single value for ENS as it had done in past IRPs. The Company explains that ENS quantities grow over time in the PaR model's Monte Carlo simulations "as a result of long-run volatility parameters that widen the spread of the Monte Carlo draws for such variables as loads. This is a statistical phenomenon intended to capture the effects of growing uncertainty as one looks farther into the future. Consequently, large ENS amounts - quantities that would be subject to the lower cost levels - occur in the out years of a portfolio simulation."[16] Further, the Company states the following:

> The Company makes the case that a high ENS cost value makes sense for near-term ENS events where there is no recourse except making emergency power purchases. However, applying that same high ENS cost over-estimates the Company's true cost of avoiding ENS occurring far into the future. As explained in the IRP and section 4.2 above, the reason is that the Company would have foresight and the lead-time to acquire other resources to prevent the ENS from occurring. Such resources would be significantly less expensive than emergency power. Since the stochastic production cost model cannot simulate this real-world planning behavior easily, using tiered ENS costs serves as a reasonable and transparent method for more realistically representing ENS costs for the stochastic simulation.
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> Regarding the OCS comment on the Company's attitude towards ENS, the IRP objective for changing its ENS modeling approach is to more accurately simulate the planning environment and portfolio costs, not downplay the importance of system reliability or the costs in maintaining that reliability. The OCS is also misinterpreting the meaning and implications of the ENS avoidance premium. The premium cited by the OCS ($659/MWh) indicates that there are cheaper options to eliminate ENS than to acquire the incremental mix of

[16] PacifiCorp's July 9, 2009, Response to Utah Party Comments, page 15.

> resources selected by the System Optimizer to meet a 15 percent planning reserve margin. For example, assuming that the stochastic average simulation results represented the real future outcome, the Company would find it economic to acquire, *when needed*, gas resources or even high-priced emergency power to eliminate the forecasted ENS. In other words, targeted investment to address potential ENS events is cost-effective relative to a portfolio optimized to meet a 15-percent reserve margin on a long-term basis.[17]

In response to the Office's recommendation for the Company to perform another LOLP study to determine the target planning reserve, the Company states it implemented an LOLP analysis method for the 2007 IRP and uses this same method for IRP 2008. Further, the associated LOLP statistics serve as one of the performance measures for portfolio evaluation. While this is not the same type of LOLP study referred to by the Office, it applies the same LOLP concepts and extends them for portfolio comparison. The Company is reluctant to undertake another LOLP study as it had done in the 2004 IRP because it is a time and resource intensive exercise that cannot be done on a regular basis given the current scope of the IRP effort. Further, the Company questions its usefulness given the controversy it generated among stakeholders in 2004, and it does not address the economics of maintaining the target LOLP and planning reserve. The Company's current approach addresses a criticism from some parties that the 2004 LOLP planning reserve study did not account for variations in resource mix, since it used a single resource type, a simple cycle combustion turbine ("SCCT"), as the proxy resource for presenting incremental reserve increases. The Company contends the IRP 2008 LOLP analysis addresses this criticism.

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[17] PacifiCorp's July 9, 2009, Response to Utah Party Comments, page 15.

Guidance on Planning Reserve and Energy Not Served

We accept the Company's tradeoff analysis meets the spirit of our direction for the Company to continue to evaluate an appropriate planning reserve. However, we are persuaded by the Division and Office, the analysis should be more rigorous in the future in order to better understand the potential impacts to reliability of alternative planning reserves. We note the expected cost differences between the two planning reserve assumptions studied, given the limited analysis in the IRP, appear to be small and choice of the most beneficial planning reserve assumption varies depending on CO2 assumptions. However, the differences in ENS are much sharper, i.e., the 15 percent planning reserve results in less ENS in all of the limited number of cases reviewed. The Company's explanation that it will change its plan to acquire resources if expected ENS grows too large is not comforting when loads or market resources can change quickly in unexpected ways, perhaps leaving little opportunity for adjustments and having a detrimental impact on reliability. We note none of the cases examined include the high or low load growth forecasts. Since the planning reserve includes operating reserve requirements, we are concerned a 12 percent planning reserve leaves little room for load forecast error.

We conclude greater attention is required in the Company's next IRP or IRP update to ensure the planning reserve analysis comprehensively evaluates reliability and identifies and balances risks to customers. At a minimum, we direct the Company to perform a sensitivity case in its next IRP or IRP update wherein the ENS cost is flat and based on the Federal Energy Regulatory Commission price cap. Additionally, in an IRP public input meeting, we direct the Company to identify a reasonable number of cases, including high and low load growth cases, to compare the costs and risks to customers, or to identify a reasonable alternative method, e.g., a LOLP study, for evaluating an appropriate planning reserve.

3. Reliance on Annual Wholesale Purchases

The Division is concerned the Company is putting ratepayers at risk by over-relying on wholesale purchases. Although the Company states one of its corporate goals is to reduce such reliance and therefore implies IRP 2008 makes progress toward this goal, the Division questions whether this is the case. The Division compares the 2007 and 2008 IRP preferred portfolios and concludes in both relative and absolute terms, front office transactions and other purchased energy are higher in the 2008 IRP than the 2007 IRP.

The Division discusses the Company's observations regarding the risks and uncertainties of resource ownership and is concerned that if PacifiCorp is unwilling to assume the risks of ownership, then it may be the case third parties are unwilling to assume them as well. Then, perhaps, no one will build and therein lies the Division's concern with the Company's long-term reliance on the wholesale market. The Division observes the Company refers to the negative correlation between risk-adjusted PVRR and the volume of front office transactions, thus noting the benefits of reducing wholesale reliance. Further, the Company states at page 41, "Portfolios with relatively high amounts of ENS rely to a greater degree on front office transactions, and in the out-years, growth resources."

In defense of its market reliance, the Company argues firm market purchases benefit the Preferred Portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. Nonetheless, the Company states it recognizes the risks with market reliance and has in place a price hedging strategy to mitigate these risks. The Division notes reliance on market purchases results in inflexibility to the extent that over short and medium time periods, the Company is locked into the vagaries of the market and cannot choose between market purchases and running its own plants. The Division supports the Company's goal of reducing reliance on front office transactions but is awaiting signs this goal is being accomplished.

The Office explains the termination of 1,011 megawatts of long-term firm purchases by summer 2012, along with reduced hydro generation due to relicensing activities, drives, in part, a rapidly growing deficit position in the Company's system of about 1,936 megawatts by 2012. The Office states the Company plans to cover a significant portion of this deficit with wholesale purchases referred to as front office transactions. Front office transactions are short-term firm purchases made on an annual forward basis.[18] The Office notes the reliance on front office transactions is especially apparent in 2012 and 2013 but the dominance of these transactions encompasses the entire planning horizon. The Office notes the Company provides a description of front office transactions by hub, product type, capacity and availability, but provides no evidence the Company's front office's analysis of near-term market opportunities is corroborated by any credible external source. The Office suggests looking at the Western Electricity Coordinating Council's ("WECC") power supply assessment in the future.

The Office is very concerned the Company's Preferred Portfolio relies heavily on short-term firm market purchases to fill a rapidly increasing resource deficit position. Though

[18] IRP 2008, Chapter 6, page 130.

the Company's Preferred Portfolio has the lowest risk adjusted PVRR (averaged across several carbon tax simulations) and rate impact, it also has the highest upper tail risk and production cost standard deviation among the B series cases examined. Further, the initial resource portfolios with greater reliance on front office transactions have higher amounts of ENS. These data confirm the riskiness of the plan, rather than justify the levels as reasonable. Further, the Office is concerned the Company assumes a firm purchase of 100 megawatts is equivalent to a 112 megawatt generating unit the Company owns, thus increasing the capacity of the firm purchase an additional 12 percent. The Office requests confirmation this is industry practice and consistent with WECC requirements.

UAE contends the Preferred Portfolio relies heavily on front office transactions particularly prior to 2013 before any new base load generation can be installed, which may now be a largely unavoidable consequence of past Company decisions. UAE argues the risk of over-reliance on market purchases is not adequately evaluated. UAE supports increased analysis of the risk that adequate market purchases may not be available and of contingency plans in case a market does not materialize. UAE recommends the Company be required to attempt to mitigate the risks associated with high level of market purchases by accelerating other available cost-effective resource options. UAE argues Guideline 4 (h)[19] was not adequately evaluated with respect to reliance on front office transactions. Further, UAE states inadequate attention is given

[19] Guideline 4 (h) requires "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."

to the cost and risk tradeoffs associated with potential market resource shortages, and therefore to Guideline 4 (j) requiring such analysis.

WRA states the Company's planned "bridging strategy" of relying heavily on front office transactions (7.7 percent of its energy mix by 2018) exposes the Company and its customers to extraordinary risk. WRA contends the bridging strategy wastes time and opportunity to address and mitigate fuel and carbon regulation risks. In failing to aggressively mitigate these risks by procuring substantial and diverse renewable resources and energy efficiency, WRA argues the Company has not provided a plan leading to an "...optimal set of resources given the expected combination of costs, risk and uncertainty."[20]

The Company provides several comments in response to parties' concerns that the Company's Preferred Portfolio relies too heavily on wholesale market purchases without providing adequate evidence the liquidity of the market is sufficient to guarantee supply, and without adequately addressing the risks of this reliance. First, the Company notes the Preferred Portfolio "...is not intended as a rigid resource acquisition strategy where the Company must match when it seeks to acquire the resource, through RFPs or other means, at future points in time."[21] Rather, the Company argues it acquires new information and reassesses market conditions and other factors, which may change the plan. To this end, the Company agrees an annual IRP update is prudent.

[20] Guidelines, page 39.

[21] PacifiCorp's July 9, 2009, Response to Utah Party Comments, page 18.

The Company's confidence is high it will be able to acquire the amounts of power to address near-term short positions resulting from the deferral of the planned CCCT resource. The Company "bases this claim on its familiarity and daily dealings with the market, and its experience in managing its operational planning position."[22] The Company cites the economic recession and the dampening of wholesale market prices as bolstering its confidence that wholesale market purchases will be sufficiently available and economic for meeting resource needs in the near term at this point in time.

However, farther out in the planning horizon, the Company states its confidence in acquiring specific volumes of wholesale market purchases declines, and therefore resource acquisition risk increases. This risk is addressed in part through the stochastic analysis in the IRP process. The Company is interested in augmenting its current risk analysis subject to possibly scaling back lower priority IRP requirements so as to manage the Company's workload and schedule constraints. Nonetheless, the Company argues its IRP is in compliance with the Commission's Guidelines and welcomes any guidance from the Commission for future IRPs.

Guidance on Annual Wholesale Purchase Reliance

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

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[22] Ibid.

docket.[23] 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.

Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office, the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to 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

The Guidelines require an evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis. The Guidelines require this evaluation include an assessment of: 1) All technically feasible generating technologies including renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources; and, 2) all technically feasible and

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[23] Docket No. 09-035-15, "In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism."

cost-effective improvements in the efficient use of electricity, including load management and conservation.

Most parties argue the IRP 2008 does not adequately consider a diversity of renewable resources. The parties argue the Company favors fossil fuel resources and market purchases. The parties argue modeling assumptions, constraints and characterizations combine to limit model selection of geothermal, solar and wind resources, energy efficiency and storage technologies. Further, the Company forces the model to select CCCTs and a 201 megawatt power purchase.

The Company defends its use of “hand-built cases” by explaining the System Optimizer does not account for the reserve and other attributes of a CCCT, which are accounted for in the PaR model. The Company describes this as a model comparability issue which it intends to investigate further so that in the future it could avoid the need to manually include CCCT resources in System Optimizer portfolios. The Company argues it compared the hand-built cases with cases in which the CCCT is not fixed and the results favor the selection of the CCCT as least cost considering risk, and therefore this concern should not be a reason for not acknowledging the IRP.

The Company includes the CCCT as a fixed resource in 2014 because that is now the earliest date in which the plant could be in commercial operation, given the time required for procurement, and given consideration of capacity load and resource balance and the uncertainty in predicting the impact of economic recovery. The Company confirms the 201 megawatt east side power purchase is treated in the portfolio optimization runs as an existing resource in 2012.

In response to the Office's request for how the sensitivity cases were defined and used to support this assumption, the Company asserts it conducted sensitivities with multiple case definitions to support placement of the 201 megawatt resource in 2012. The Company expects adjustments to its near-term resource plan in response to changing planning conditions, and plans to reflect such changes in its 2010 business plan and 2008 IRP update.

In response to the Division's concern the Company did not adequately vet the hand-created portfolios excluding the Lake Side 2 plant, nor perform the third step of analysis to evaluate the robustness of the final portfolios relative to alternative future scenarios, the Company argues it did not have time. The Company believes performance of the third step would not alter conclusions of the top performing portfolios and bases this conclusion on the findings of the original risk assessment study.

In response to the Office's concern the Company inappropriately applied its 12 percent planning reserve assumption to wholesale purchases, the Company responds that the Office may have misunderstood the narrative describing reserves and firm purchases. The Company intended this to mean the counter-party would hold the reserves rather than that the purchase would add 12 percent in reserves on top of the avoided reserve requirement.

With respect to parties' concerns that the Company appears to be biased against new technologies, understates or mistreats certain resources or has inappropriately applied constraints on wind, the Company replies it does not have a systematic aversion to new technologies. The Company argues it commissioned an independent analysis, conducted by WorleyParsons in 2008, on solar thermal, geothermal, and biomass generation characteristics to ensure the resource cost assumptions are reasonable. The Company also points to its action plan to investigate and acquire cost-effective solar and emerging technologies within the next 10 years. Nonetheless, the Company believes new technologies present added risks and therefore the Company takes a conservative stance when defining cost values to use for IRP modeling purposes. The Company argues this is prudent utility practice and is consistent with the IRP requirement to consider risk and uncertainty. While others may disagree, the Company argues it does not constitute a failure to meet the Guidelines.

The Company explains it went to considerable effort to develop the resource characterizations for this IRP and argues it faced significant technical and schedule challenges given the number and variety of resources covered. The Company defends its treatment of geothermal plant capacity, 105 megawatts, as reflecting a reasonable assessment of commercially available project opportunities, particularly in the near term. The Company supports its view that commercial opportunities are limited by noting it received no geothermal resource bids in its recent renewable Request for Proposals.

Regarding the Division's concern the model should select fuel cells because this resource is low cost, the Company explains the manual fixing of a CCCT by 2014 is the key factor influencing the selection of fuel cells and other resources early on in the simulation period. The System Optimizer selects fuel cells in six of the eight "B" series portfolios that exclude a fixed CCCT. With the CCCT included as a fixed resource in the model, other resource selection factors come into play. Fuel cells compete not only with utility scale supply side resources but also demand-side management, distributed generation, and market purchases. Interplay between resource size, magnitude of capacity requirement, and resource availability, all help determine if and when resources are selected by the model.

The Company argues the reason for applying a capacity size threshold for distributed resources is to help maintain a manageable model size. To address concerns with this strategy, the Company performs a sensitivity case where size constraints are relaxed for rooftop solar photovoltaic and water heaters and still the model does not select these resources.

In response to the Office's concern about the artificial annual limits on wind resources, the Company states it applied these constraints to ensure an unrealistic amount of wind capacity is not added in any given year – the constraints do not limit the total amount of capacity added. The constraints were developed in consultation with Company employees responsible for wind acquisition and construction and consider wind turbine availability, transmission constraints and procurement requirements. The Company opposes performing additional sensitivity analysis because the overall quantity of wind is not affected and there would be no rationale for selecting an alternative set of constraints given the original values reflect the best judgment of Company wind acquisition experts. Regarding parties' concerns with the manually determined wind resource schedule, the Company decided to keep this type of constraint out of the quantitative modeling but is interested in stakeholder reaction to applying such a constraint.

Guidance on Consistent and Comparable Resource Evaluation

The Company's attempt to characterize and include a greater variety of resource types is a positive step toward addressing the Guidelines' requirement for the Company to evaluate all known resources on a consistent and comparable basis. We understand some resources may be relatively small and present modeling challenges, however, we expect the evaluation of these non-traditional resources to evolve and improve in each IRP.

We direct the Company to 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 which provide opportunities for customer participation, i.e., a solar rooftop customer buy-down program, and options for improving the evaluation of storage technologies designed to enhance the value and performance of intermittent renewable resources.

We also concur with the Division and Office regarding the need for review of geothermal resources and direct the Company to file a geothermal resource study as described by the Division within 60 days of the date of this order. We will initiate a comment period upon its filing and this information can be included in the next IRP or IRP update.

We also note a complication in this IRP was the Company's decision to include a planned resource as an existing resource, i.e., the Lake Side 2 power plant. In the future, the Company is directed to omit from its core cases any resource for which it does not already have a signed final procurement contract or certificate of public convenience and necessity. However, this does not preclude the Company from including such resources in sensitivity cases. This will assist with the consistent and comparable treatment of resources going forward.

B. Load and Resource Balance

The Division and Office raise issues affecting the Company's calculation of load and resource balance and therefore the timing and amount of resource deficit. Both cite concerns with the planning reserve assumptions which are discussed above. The Office additionally raises issues regarding the Company's load forecasts and about hydro generation capacity contribution in the analysis of load and resource balance.

1. Load Forecasts

Our Guidelines require the Company to include a range of energy and capacity load growth forecasts. In IRP 2007, the Company had changed its base load forecast at the end of the public process and we found this change to be inadequately supported. We questioned the need for the Company to make such a change given it could evaluate resource requirements under a range of load growth forecasts and given it takes into account historic load variability in its stochastic analysis. Therefore we directed the Company to examine the range of load forecasts in its scenario and stochastic analyses and to address load forecast error risk, especially with respect to its one-hour peak demand forecast based on a 30 year normal temperature, and also to evaluate the role of planning reserve assumptions.

Once again, in IRP 2008, the Company changed its base forecast at the end of the process, causing delay and the development of final portfolios that were, arguably, not directly comparable with its widely reviewed initial set of alternative portfolios and sensitivity cases.

Parties' comments state the Company convened a public input meeting to provide an overview of its new forecast methods. Specifically, the Company elected to move from its in-house load forecasting methods to industry software by ITRON.

The Office hired a consulting firm, GDS Associates, Inc., ("GDS") to examine the load forecast prepared by the Company and used in its 2008 IRP. This included a review of both the November 2008 forecast used for 48 portfolios and the February 2009 forecast used in the 10 final portfolios. GDS notes the energy sales from 2009 to 2018 in the November 2008 forecast are about 1.1 percent to 2.2 percent higher than the February 2009 forecast. Peak demands over the same period are about 1.4 percent to 3.4 percent higher in the November 2008 forecast.

GDS concludes the Company's forecast methodology and models meet or exceed industry standards. However, GDS argues the Company's range or scenario forecasts are inadequate for resource planning purposes.

GDS states the demands provided in the 2008 IRP are base case projections, meaning there is a 50 percent probability the actual load will come in either above or below the projected demand. The high and low peak demand sensitivities used in IRP 2008 change the average growth rate of the base forecast by +/- 1 percent. This results in a 2018 peak ranging from about +/- 9 percent. GDS argues "it is not out of the ordinary for extreme weather conditions to cause demand to change by more than +/- 10 percent and depending on several system-specific factors could be as much as +/- 15 percent."[24] Therefore, GDS recommends the

[24] Office Comments, June 18, 2009, Attachment 3, GDS Evaluation of PacifiCorp's Load Forecast, page 14.

Company consider multiple scenarios for its peak forecast. Industry standard would be to include scenarios - such as optimistic and pessimistic economic conditions and high and low weather scenarios. GDS notes certain software files contain simulations that could be used to develop range forecasts. Scenarios should, at a minimum, include optimistic and pessimistic economic scenarios and extreme and mild weather scenarios. At the very least, the weather scenarios should account for a 5 percent probability of occurrence (the most extreme or mild weather scenario in a twenty year horizon).

In response to the Office's recommendations, the Company essentially argues it is compliant with the Guidelines because it used the same method for establishing a range of forecasts, i.e., scenario and stochastic analysis, it used in IRP 2007.

Guidance on Load Forecasts

We remind the Company we found its approach questionable in IRP 2007. Indeed we stated, "Either the stochastic and scenario analyses with respect to load growth are adequate and reasonable for planning purposes or not." Specifically, we had directed the Company, in its next IRP process, to convene a public input meeting or technical workgroup session to review its approach to load forecast variation and to address the issue of load forecast error risk. We noted this discussion must include the Office's concerns regarding use of 30-year normal temperatures for estimating peak demand, the number of years relied upon for developing stochastic parameters, and the role of planning reserve in managing the risks of forecast error. It is our understanding the Company now uses a 20-year normal temperatures but the other two issues are not addressed in the IRP. Therefore, we again direct the Company to address these issues in the next IRP or IRP update.

We appreciate the Office providing us with the GDS report, addressing, in part, the issues raised in our last order on IRP. We recognize the GDS report was not available for consideration in the formation of IRP 2008 and therefore direct the Company and interested parties to examine and consider all of the suggestions contained in this report. At a minimum, the Company is directed to provide a range of load forecasts that comport with industry standards as recommended by GDS. Further, as recommended by GDS, we direct the Company to provide the Commission with a comprehensive stand-alone load forecast report when the forecast is updated. The GDS suggestions could reduce last minute revisions due to load forecast changes and thereby assist in the timely completion of future IRPs.

2. Hydro Capacity Accounting

The Office restates the concerns it raised in the 2007 IRP wherein: 1) The method for calculating hydro capacity appears to overstate the Company’s load and resource position and exposes customers to further market risk; and 2) the WECC is considering adopting an alternative method referred to as the “sustained peaking capacity” concept. This method involves the average hydro capacity available during the six highest load hours for three consecutive days of highest demand. The Office recounts that the Commission directed the Company to address this issue in its next IRP and notes the Company did not. The Office states the Company conducted a “cursory” analysis of hydro capacity using the two methods and concluded the differences in results are immaterial.

The Office recommends the Commission should again direct the Company to provide a thorough analysis of the impacts associated with moving from a one-hour sustained period to an 18-hour period for determining hydro capacity to meet peak hour requirements in its next IRP. The Division contends the Company has met this requirement, but notes the Company did not provide its analysis for review. The Division recommends the Company provide an in-depth analysis of the Northwest Power and Conservation Council method and continue to evaluate how to implement this method in its next IRP. The Company does not address this issue in its response to parties comments.

Guidance on Hydro Capacity Accounting

We again direct the Company to address this issue in its next IRP or IRP update and provide the results of its analysis. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of the current methodology.

C. Wind Integration Costs

The Division is unable to determine the reliability of the Company's estimate of wind integration costs. The Division recommends the Commission require the Company to complete its own wind integration cost study and file it with the Commission as soon as it is completed. The Division provides a detailed analysis of the Company's proxy wind integration costs and requests the Company consider its findings and methodological concerns as it works on its own wind integration study. The Division also recommends parties have the opportunity to comment on the study prior to its use in the next IRP. Should the study be completed prior to the Company's IRP Update, the Division recommends the Company perform a sensitivity study using the System Optimizer and the 2008 IRP Preferred Portfolio modeling assumptions, including the proxy value of $11.75 per megawatt hour from the Portland General Electric study.

The Division, Office and Interwest note the 2008 IRP wind integration costs range from $9.96 to 11.85 per megawatt hour depending on CO_2 tax level and argue these values are more than twice the assumed wind integration cost in 2007 IRP and much higher than many other wind integration cost studies.

Guidance on Wind Integration Cost

We concur with the Division and direct the Company to complete its own wind integration study. We understand this process is underway and that the Company is circulating the study for review. We direct the Company to address the Division's concerns and include this study in the next IRP or IRP update.

D. Resource Acquisition Paths and Decision Mechanism

The Guidelines require 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. The purpose of this guideline is to provide resource acquisition path contingencies for big picture changes affecting the type, amount and timing of resources to produce a least cost expansion plan considering risk and uncertainty.

The Company reviews four risk areas for the acquisition path analysis in IRP 2008. The four risk areas are 1) regulatory events; 2) load growth; 3) natural gas prices; and, 4) procurement delays. The Company presents high-level contingency resource strategies for it to consider when faced with significant changes in resource planning relative to these four areas. The acquisition paths reflect resource types rather than quantities and timing. The Company's proposed decision mechanism for pursuing resource strategies is "the outcome of the business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions."[25]

The Division commends the Company for implementing acquisition plan analysis but argues the decision mechanism needs more specificity for path changes under different circumstances. Therefore, the Division concludes this Guideline is not met. Full compliance with this Guideline requires more specific actions. "For example, the optimum base portfolio (presumably the preferred portfolio) would be based upon the Company's "most likely" future scenario. Then several optimum portfolios could be derived for significant departures from the most likely scenario. Had this decision mechanism been performed the way the Division envisioned it, there would have been an alternate path mechanism when load growth declined and Lake Side 2 was taken out of the resource mix. This would have obviated the delay in the IRP filing itself." Further, the Division believes the path analysis related to transmission projects is weak.

Guidance on Resource Acquisition Paths and Decision Mechanism

We commend the Company on addressing this requirement in IRP 2008. While we concur with the Division the specificity of the decision mechanism is lacking, we believe the matrices provided in the action plan are a step in the right direction of complying with this

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[25] IRP 2008, Chapter 9, page 267.

Guideline. Therefore, we direct the Company to solicit and discuss further improvements to its resource acquisition path analysis and decision mechanism and address the Division's concerns in it next IRP or IRP update.

E. Business Plan Link

Commission Guidelines require the Company's strategic business plan to be directly related to the IRP to ensure ratepayers receive the benefits from IRP. This requirement is expected to be met through Guidelines 4 (e) and 4 (h). Guideline 4 (e) requires "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." Guideline 4 (h) requires, "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."

In the IRP 2008 action plan, the Company describes the linkage of the action plan to the Company's business planning. The Company states the IRP is a primary tool in business planning and that it made a concerted effort to align these two processes in the development of the 2008 IRP. The Company states the business planning process addresses the impacts of resources on the Company's financial health, electricity rates, and the prospects for successful recovery of shareholder investments. The Company considers resource affordability and financeability as checks that the IRP's long-term planning perspective comports with prudent utility business practices in today's commercial and regulatory environments.

To align the two processes, PacifiCorp Energy's finance department analyzed the major resource differences between the 2008 Preferred Portfolio and the 2009 business plan approved by the MEHC board of directors in December 2009 for rate and financial impacts. This analysis also supported credit rating agency review of the business plan. The Company describes the major resource changes as the deferral of the CCCT to 2014 from 2012, deferral of the SCCT to 2016 from 2013, and a modified wind acquisition schedule wherein the Preferred Portfolio includes an additional 450 megawatts from 2009 to 2018.

The Division reviewed the Company's Business Plan and believes the primary assumptions in the Business Plan and IRP are generally aligned with two exceptions. First, modeling was not performed on time on the reference cases to meet this procedural requirement. The Division fails to understand how the IRP can inform the Business Plan if IRP analysis is conducted months after the Business Plan is approved. Second, the Company included the Lake Side 2 plant in the Business Plan but not the IRP.

The Division and Office note two of the Company's planned alignment strategy objectives were not met. First, it did not conduct alternative portfolio development for the Business Plan using different input assumptions and did not compare portfolio stochastic costs and risks. Second, it did not report on the progress of the Business Plan preparation. The Company stated, "...as a consequence of the IRP modeling delay, the business plan was approved by the MEHC board of directors in December 2008 - prior to the completion of IRP modeling and selection of the 2008 IRP Preferred Portfolio.”[26]

The Division was unable initially to obtain a copy of the 10-year business plan but the Company reported that the assumptions in the business plan for load forecast, forward price curves, resource cost and performance attributes mostly align with the IRP. However, with respect to the three planning scenarios newly created in the IRP to align the business plan with the IRP, the Company replied that documenting such assumptions would be an onerous task.

The Division recommends the Commission clarify the directional link of the Company’s 10-year business plan to its IRP. The Division believes if they are to inform each other, then they need to be developed in some manner of synchronization. The Division requests the Commission clarify the Guidelines to say, “The Company’s 10-Year Business Plan must be directly related to its Integrated Resource Plan.” The Division recommends the Company hold an in-person, all-day stakeholder meeting in January of each year devoted to reviewing the Company’s 10-year Business Plan.

The Office also concludes the Company has failed to comply with the intent of this Guideline. The Office notes the 2009 business plan was completed months before IRP modeling was completed. The key reason for extending IRP modeling, the Office states, stems from the Company’s business decision to cancel the Lake Side 2 contract in February 2009. Following this decision, the Company removed Lake Side 2 as an existing resource in 2012, used a new load forecast and added five new assumptions relating to additional transmission access

[26] IRP 2008, Chapter 2, page 22.

and greater wholesale market depth at certain western market hubs. This resulted in a new preferred portfolio matching the Company's prior decision to terminate the Lake Side 2 contract. This sequence of events, the Office argues, demonstrates the business planning process shaped the 2008 IRP process and directly influenced the Company's choice of preferred portfolio.

The Office argues alignment of the two processes cannot be judged simply on whether the assumptions and results are the same. Rather, the Office argues, the Company should be required to fully support all of the assumptions used in the IRP and demonstrate their appropriateness.

WRA argues the Company's treatment of CO_2 risk in the IRP and business plan is inconsistent. The Company's business plan CO_2 price starts at $8.79 per ton in 2013 and grows to only $11.68 by 2028. WRA believes the IRP uses more realistic prices of $45 per ton and higher.

The Company disagrees with the Division and Office and contends it did in fact link the business plan with the Lake Side 2 decision and the IRP which it described in the action plan section of the IRP. The Company argues the Division and Office focus too much on the last several months of IRP analysis in 2009 and ignore the Company's use of the System Optimizer model to develop resource portfolios for business planning throughout 2008. Further, the Division and Office ignore the consulting role the IRP department played in supporting the business plan.

With respect to the timing of the business plan and IRP, the Company argues it is unreasonable to expect the two to be in lock step. The Company concurs with the Office's conclusion that the business planning process shaped the 2008 process; the Company argues it's alignment strategy was not intended to be a one-way flow of information and influence. In response to WRA's comment regarding the different CO2 tax assumptions, the Company states the business plan requires a point estimate rather than a range. The Company argues its CO2 price assumptions are reasonable given none of the potential CO2 regulatory policies under consideration in 2008 were developed with sufficient detail to provide more accurate costs for the business planning horizon.

Guidance on IRP and Business Plan Link

We wish to address two issues with respect to this Guideline. First, we recognize the IRP and the business plan are not one and the same. While the planning processes will inform each other, they are separate processes with distinct purposes, different participants and potentially different considerations.

The IRP is designed to identify the optimal plan to serve the long-run public interest and invite interaction and information exchange between the Company, regulators and other interested parties. It is also one way in which we can engage in long-range planning as required in UCA § 54-1-10.

The business plan is directed by Company management and reflects the Company's financial interests to a greater extent than the IRP. The Company states "...the business plan focuses on maintaining a strong financial position while ensuring a customer's generation needs are met economically given the expected operating environment."[27] Further,

[27] IRP 2008, Chapter 2, page 20.

the Company explains the business plan is an annual process involving frequent input assumption updates and the preparation of multiple versions of the plan for internal prudence reviews. Company investment decisions and actions are not judged in the IRP acknowledgment proceeding. Indeed, Guideline 7 states, “Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.”

However, Guideline 8 states, “The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost determinations.” The IRP must have sufficient detail and documentation, and be relatively timely, to enable regulators to evaluate Company resource decisions given information available at a point in time.

While we concur with the Company the planning processes should inform each other, we also concur with the Office, the Company must fully support all of the assumptions used in the IRP and demonstrate their appropriateness for serving the public interest, including the use of any business planning assumptions.

The objective of the guidelines addressing the link between the Company’s strategic business plan and the IRP is to ensure transparency between the two plans such that any differences are easily understood and the benefits of IRP are brought to customers; it is not to make sure the plans match exactly at any given moment. Because changes affecting planning can occur any time, it is expected the IRP and business plans may diverge as assumptions are updated in one or the other plan. In our order on Guidelines, and per R746-430-1, we directed the Company to identify in its IRP action plan, how its actions for implementing the IRP are consistent with its strategic business plan. We do not dictate how this is to be done. Planning processes should be flexible enough to incorporate improvements over time.

This brings us to our second issue. We are concerned by the actual and potential delays and complications presented in the IRP process due to the Company's alignment strategy. By this we mean the development late in the process of additional portfolios not directly related to the fully vetted assumptions in the IRP or the resulting lack of time to fully complete the portfolio evaluation process. The IRP is intended to be a long-run evaluation of serving the public interest. Use of a broader range of loads, for example, should assist in avoiding last minute changes to the IRP without compromising the process or rendering the IRP obsolete. The business plan by its nature may require more frequent updating due to changes in the short run. We expect the Company to update its IRP as necessary, through either annual updates as in the past or through updated action plans submitted per R746-430-1.

It appears the Company's proposed linkage process may have curtailed the time for public review and information exchange with the Company. This has caused some parties to conclude the IRP is inconsistent with our Guidelines and therefore should not be acknowledged. While we conclude the information flow between the two processes should be bidirectional, the attempt at alignment must not compromise the IRP process. For example, initial cases or optimized portfolios should not be dropped from the evaluation process solely on the basis of business plan considerations. The IRP process and schedule must be maintained and adequate time and sufficient documentation provided for regulatory and public input and review. We support the approach used by the Company in IRP 2008 wherein the Company included business plan reference cases and evaluated these cases in comparison to the other broadly defined cases. This approach provides transparency between the two planning processes and allows cost-risk tradeoff analysis of the business plan and other alternative portfolios, but can be done within the integrated resource planning process analytical time frame.

F. Public Process

The Guidelines require an open public process and biennial filing of the IRP. As part of the 2008 IRP process, the Company hosted five full-day public input meetings, two half-day meetings, one conference call and six state-specific meetings between February 2008 and March 2009. Presentations and discussions during the meetings addressed inputs and assumptions, risks, modeling techniques, and analytical results. These meetings coupled with use of video-conferencing and telephone access allow ample access for participation from Utah stakeholders.

Several issues are raised in comments. First, parties recommend improvements for the process going forward. Second, the Company proposes a schedule for the filing of the IRP that it contends will better align its business planning process with its IRP process. This schedule consists of a filing deadline of March 31 of each odd year. Parties provide recommendations regarding this schedule.

1. Procedural Issues

The Division argues the Company has not adequately complied with the Guideline 3 which requires the Company to provide ample opportunity for public input and information exchange during the development of the plan. For a period of approximately seven months, there were no in-person general meetings. During this period, the process was not transparent and there was little opportunity for information exchange. The Company subsequently developed another 10 portfolios without public input to account for the removal of Lake Side 2. The cases were developed using the original top performing portfolios and the Division questions which portfolios would have resulted in the top-ten performing portfolios had the analysis been conducted consistently and without the Company assuming from the start Lake Side 2 would be an existing plant.

The Division recommends three changes to the IRP public process. First, it recommends a more formal process for information exchange, public meetings, and filing dates. The Division argues greater formality in the beginning of an IRP cycle would improve the transparency of the IRP process and allow better information sharing. To this end, the Division recommends the Company file a notice with the Commission that it is beginning a new IRP public process, thus initiating a docket at that time. The Division recommends all materials, data responses, etc., be filed in the docket rather than at the end of the year-long process when the Company files its draft IRP.

Second, the Division recommends the following improvements to the public meetings: Materials need to be distributed one week prior to the meeting; a written report of the material to be covered should be provided prior to each meeting; and a summary report should be provided after each meeting to provide a follow-up to issues or questions raised in the meeting. Third, the Division recommends the Company provide hands-on training for the System Optimizer and PaR models and provide parties access to any data or other models used by the Company in its planning process. The Division recommends regulators have the opportunity to evaluate each model and its assumptions, or to validate the results, which will require more than a brief power point presentation of a model.

The Division argues these changes could address the Commission's directive in its order on IRP 2005 for the Company to "structure the public input process to allow sufficient time for discussion of issues raised by parties and to address relevant issues raised in this IRP" and also to "investigate improving the transparency of the IRP modeling to increase confidence in the results."[28]

UAE recommends the Company use less cumbersome, more transparent, available IRP models which are better adapted to a fast changing environment. UAE recommends the Company review its modeling execution to better manage the tradeoffs between updating information and having adequate time both to run the models and to provide for stakeholders to review and perform analysis. UAE recommends the Commission schedule a hearing to receive comments from interested parties regarding the IRP process and then provide specific guidance and input to the Company regarding the action plan and the Commission's expectations for future IRPs.

The Company states it expects to integrate the System Optimizer and Planning and Risk models into the same platform in 2010. This, the Company argues, will help with model execution and management. Regarding the recommendation to adopt different models,

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[28] July 21, 2005, Report and Order, Docket No. 05-2035-01, "In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan 2004," page 21.

the Company states it periodically assesses other model packages for better capabilities, user friendliness, portability, and life-cycle costs. But converting to another modeling system would likely be a major undertaking.

Interwest states PacifiCorp has produced a well-founded and thorough plan document. It argues IRP 2008 includes a detailed analysis of relevant information and is relatively easy to understand. However, Interwest argues the IRP 2008 fails to incorporate the logical results of the modeling techniques as reported in the document.

WRA concludes that much of the 2008 IRP's deficiency stems from the Company's reluctance to aggressively confront and mitigate the risks and uncertainties it faces and this presents undue and unnecessary risk to the Company and its customers. Therefore, WRA requests the Commission exercise its prerogative within Procedural Issue 4 to "pursue a more active-directive role" in the Company's planning. At a minimum, PacifiCorp should be directed to pursue the renewable generation and energy efficiency called for in Portfolio 8. Further, the Company should be directed to model a diversity of renewable generation resources and their different operating characteristics, pursue storage technologies to complement its renewable energy development, enhance the development of distributed generation, and deploy substantial demand side resources that are modeled as unreliable.

The Company objects to the Division's process recommendations and argues the added requirements will increase the administrative burden and complexity of the IRP process rather than improve it. The Company argues it must comply with over 160 individual state IRP requirements and expects more at the conclusion of the 2008 IRP acknowledgment process. The

Company contends these added requirements would increase the IRP department's workload to an unsupportable level. The Company states the IRP department consists of five employees that develop the IRP and support the business planning and procurement processes. Likely, the additional requirements would require the Company to reduce the number of meetings and reduce other support activities to the overall detriment of the IRP process. Further, the greater process formality appears to lead in the wrong direction, i.e., towards the formality of a rate case proceeding and may hinder a more collaborative planning process approach.

However, the Company believes the recommendation to provide an IRP model workshop with simulation demonstrations has merit and provides suggestions for how this could be accomplished.

Guidance on Procedural Issues

In order to ensure timely and meaningful information exchange, we direct the Company to adopt two of the Division's recommendations on improving public input meetings. First, materials should be distributed one week prior to the public input meeting. Secondly, a written report should be provided after each meeting to provide follow-up to issues or questions raised in the meeting. We will not at this time adopt the Division's recommendations to open a docket early in the process. We believe the Company has a website it can use to post all information, including inquiries and responses from all states that are not confidential. If this approach does not address the Division's concerns, we will consider the Division's recommendations at a later time.

We concur with the Division and UAE, training on the Company's models in order for parties to validate the models and to gain confidence in the modeling results is worthwhile. We direct the Company to convene at least a full-day meeting to this end.

2. IRP Filing Schedule

The Company proposes to file its biennial IRP on March 31 of each odd-numbered year, commencing with the next IRP to be filed by March 31, 2011. The Company states this will ensure the IRP is aligned with the Company's 10-year business planning process and address the Commission's IRP Guideline 4 (e), which requires the IRP action plan to "outlin[e] the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan."

The Company states "The selection of the March 31 filing date is intended to provide sufficient time to align the final business plan as approved by the MEHC board of directors in December with the IRP preferred portfolio and action plan." The Company states it needs one full year to complete the IRP. It uses the IRP models to develop resource portfolios in October and November to support resource decisions made for the final version of the business plan. Following resource plan approval by the MEHC board of directors in December, the Company then develops the IRP action plan and prepares the IRP draft report for public comment in January and February. The action plan is then used to determine the request for proposals to be issued and identify other resource procurement activities. About two or three additional weeks are then needed to conduct the acquisition plan analysis as required by the Guidelines.

The Division questions the Company's rationale for its proposed schedule change. Although the Company argues the point of the schedule change is to align the Company's business plan and IRP processes, the Division states the schedule produces an IRP after the business plan is approved, making it impossible for the IRP to inform the business plan.

To ensure it is the IRP that informs the business plan, the Division recommends the following changes to the Company's proposed schedule: 1) Establish an IRP schedule such that the IRP analysis, including path analysis and the development of the preferred portfolio and action plan, is substantially complete by December when the Company presents the plan to the MEHC board for approval; 2) at the time the Company presents the plan to the Board, it also files a draft of the IRP, preferred portfolio and action plan with the Commission; 3) the filing with the Commission begins a 60-day comment period wherein interested parties submit comments to the Company; 4) within 30 days of MEHC approval of the business plan, the Company files a report detailing the changes to the preferred portfolio made by the MEHC board, the reasons for the changes, and the approved business plan; 5) the Company files its final IRP with the Commission by March 31 and identifies any changes from the draft to the final IRP; 6) parties file comments with the Commission on acknowledgment of the final IRP; and 7) if the IRP is not acknowledged, the Company would respond to the issues raised in the Commission's order and resubmit the IRP for final acknowledgment.

The Office does not conceptually oppose the Company's proposed March 31 filing date. However, the Office believes the Company must be held to the filing deadline in the future. Further, the Office argues the Company should be required to align the business plan with the IRP rather than the business plan shaping the IRP. For example, IRP assumptions must not only be aligned with the business plan but must also be identified, explained and supported with verifiable evidence.

The Company argues the Division's recommended filing schedule will prevent it from maintaining a direct link between the IRP and business plan and will undo the Company's progress in aligning the two processes. The Company argues October and November are devoted to developing resource portfolios to support resource decisions made for the final version of the business plan. The Company contends the Division's schedule disregards this stage of IRP analysis by forcing the Company to divert IRP staff from business planning support activities and to the preparation and filing of the draft IRP. The Company asserts this will cause the IRP and business plan to diverge. Further, the time spent preparing a report describing differences between the IRP and business plan can be avoided by not requiring substantial completion of the IRP by December.

Guidance on Schedule

No party opposes the Company's proposed IRP filing date of March 31 of each odd year. We find it reasonable to have a firm date to enable better scheduling of the process and to ensure timely completion of future IRPs and therefore accept this filing date.

In order to address some of the Division's concerns but also account for Company resource issues, we direct the Company to make the IRP information which is provided to the board in the December time frame available to parties upon request. As stated earlier in our guidance regarding the link between the IRP and the Company's business plan, the Company must fully support all of the assumptions used in the IRP and demonstrate their appropriateness for serving the public interest, including the use of any business planning assumptions. Further, the alignment process must not compromise the IRP process. The IRP process and schedule must be maintained and allow adequate time for public input and review.

III. CONCLUSIONS

We commend the Company for producing a more transparent plan than in the past. We, like Interwest, found the document fairly easy to navigate and the Company has provided comprehensive documentation and explanation throughout the two volumes on most issues. We also appreciate the hard work and thoughtful comments provided by regulators and interested parties. These comments will serve to ensure continued improvement and usefulness of the IRP process. We recognize that each IRP is measured by the next level of expectations and parties have identified issues that require additional work as discussed herein.

Given our view the IRP is an evolving process, we find the Company has generally complied with our Guidelines, subject to the guidance we have provided herein, and therefore acknowledge this plan. We note, once again, acknowledgment does not guarantee favorable ratemaking treatment of future resource acquisition decisions. Indeed, we are not convinced the Preferred Portfolio is the optimal portfolio. For example, more comprehensive support than is provided in IRP 2008 is necessary to conclude it is in the public interest to rely on annual market purchases to the extent included in the Preferred Portfolio or to plan to a 12 percent planning reserve. We also conclude the Company must provide better support for its range of load forecasts and as discussed herein, we direct further work in this area to be included in the next IRP or IRP update. Per R746-430-1, we will provide notice of a scheduling conference each time the Company submits an action plan related to an IRP in order to set a schedule for discovery and comments.

IV. ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that

1. The IRP 2008 is acknowledged subject to the guidance provided herein.

DATED at Salt Lake City, Utah, this 1st day of April, 2010.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#65978