State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: Public Service Commission of Utah

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Date: May 5, 2006

Subject: Comments of the Committee of Consumer Services regarding PacifiCorp's *Integrated Resource Plan 2004 Update*; Docket No. 05-2035-01

1 SUMMARY AND RECOMMENDATION

The Committee of Consumer Services (Committee) appreciates the opportunity to comment on PacifiCorp's *Integrated Resource Plan 2004 Update* (*Update*) and its connection to the upcoming resource solicitation process and other regulatory proceedings.

The Committee believes that the resource portfolio identified by the *Update* as the least cost, least risk portfolio is an improvement over the portfolio identified by *Integrated Resource Plan 2004* (*IRP 2004*). We commend the Company for its responsiveness to stakeholder input in conducting the *Update*. The new portfolio identifies a coal-fired resource as the next major resource addition, reduces the ratio of gas-fired to coal-fired acquisitions, and adds a transmission upgrade. These changes reduce the gas price risk inherent in the previous action plan and better integrate the PacifiCorp system.

However, the Committee cannot endorse the Update Portfolio as least cost, least risk. The Committee remains alarmed by the unevaluated market risk inherent in the Company's acquisition strategy—a risk that the Company appears no longer willing to share as evidenced by its Power Cost Adjustment Mechanism (PCAM) filing.

Since wind and coal are the only feasible technologies, other than nuclear, that reduce market reliance while not increasing gas price risk, the Committee encourages the Company to make every effort to lockdown such resources as quickly as possible and to proceed expeditiously with what has become its 2012 RFP. We note that *IRP 2003* sited in calendar year 2007 what is now the 2012 proxy coal plant at Hunter.[1] The *IRP 2003 Update* slipped its timing to 2008. *IRP 2004* initially targeted 2010 for this same addition and then slipped the online date to 2011. The current IRP slips this proxy plant by still an additional year—a full five years past its acknowledged in-service date.

While we recognize that the Company may now be unable to build a coal-fired resource prior to the summer of 2012, power with similar characteristics might be available earlier through the solicitation process and, if so, should be considered.

The Committee makes the following recommendations:

(1) We urge the Commission to indicate its concern with the Company's exposed position including the unevaluated risk of the significant volume of shorter-term market transactions embedded in the IRP and to direct the Company to work with stakeholders to model the risk of these transactions in the current IRP process. If the Commission determines that it will "review and provide guidance" to the Company through an acknowledgment order, the Committee recommends that the Commission not acknowledge the IRP unless the order makes clear that the Company will bear the risk for its exposed position or addresses explicitly in what forum this issue will be decided.

(2) The Committee recommends that the Commission direct the Company to use the same assumptions for planning and ratemaking. If planning and ratemaking

[1] For the purpose of these comments all dates are in calendar years. Dates from IRPs that were originally linked to Scottish Power's fiscal year have been converted.

assumptions are consistent, the Commission and stakeholders can have greater confidence that PacifiCorp stands behind its assumptions, since it would bear a share of the cost of being wrong.

(3) We further recommend that the Commission direct PacifiCorp to evaluate a larger upgrade of Path C, include additional transmission alternatives, evaluate the inclusion of non-firm transmission, consider a larger 2014 coal resource, and assess additional wind in its current IRP process.

(4) With regard to process, the Committee recommends that the Commission provide review and guidance within the IRP docket. It could do so in memo form or as an acknowledgement order. Finally, we recommend that comments received on the *Update* should be incorporated into the body of data and information to be considered in the pending RFP docket, 05-2035-47.

2 BACKGROUND

On June 18, 1992, the Commission promulgated Integrated Resource Planning Standards and Guidelines (Standards and Guidelines). These require the Company to file an IRP with the Commission biennially, including an action plan that outlines the specific actions that must be taken in the next two years and those anticipated in the following two years. The Commission solicits input from interested stakeholders. After a full review of the plan and the comments, under the terms of the Standards and Guidelines, the Commission acknowledges or declines to acknowledge the IRP and/or its action plan; cost recovery of new resources is determined during a rate case.

In accordance with the requirements of the Standards and Guidelines, the Company filed *IRP 2004* on January 20, 2005 establishing Docket No. 05-2035-01 (IRP docket).

Nineteen days later, the Utah legislature passed Senate Bill 26 during its 2005 general legislative session. The Governor signed the bill February 25, 2005 enacting the Energy Resource Procurement Act (Procurement Act). This act establishes a legal framework for the competitive acquisition, approval, and cost recovery of significant energy resources (100 MW or larger with a life of 10 years or more).[2] The act addresses the IRP action plan in connection with a formal solicitation process and makes activities in IRP dockets pertinent to other dockets.

On February 20, 2005 the Commission issued a “Request for Comments” in the IRP docket. It requested comments on the appropriateness of the *IRP 2004* report and invited interested parties to make recommendations on whether the Commission should acknowledge the plan. Of the five sets of comments filed April 22 and April 25, only one supported acknowledgement.

[2] It provides for a competitive solicitation process under the oversight of an independent evaluator. It directs the affected utility, PacifiCorp, to file with the Commission any action plan developed as part of the utility’s IRP to enable the Commission to review and provide guidance to the utility. Finally, it assures that resources that result from a competitive solicitation process and are approved by the Commission receive cost recovery. The act directs the development of Commission rules to govern the solicitation and approval processes. This rulemaking is in process; no final rules are expected before the fall of 2006.

On June 27, 2005, the Company began the solicitation process required by the Procurement Act. It filed a “Request for Approval" of its *2009 Request for Proposals for a Flexible Resource* (RFP 2009), a resource consistent with the resource need identified by *IRP 2004*. This filing established Docket No. 05-035-47 (RFP docket).

The Commission issued its order in the IRP docket on July 21, 2005. The Commission acknowledged *IRP 2004* as generally consistent with the Standards and Guidelines. However, the Commission declined to acknowledge its action plan, noting parties’ concerns with the type, timing, and magnitude of the identified resources because of concerns with faulty or outdated assumptions. It requested that parties provide input on these matters through the active RFP approval process. It stated:

> SB 26 gives us a new opportunity to address these concerns in a meaningful and timely way through the RFP approval process. Input assumptions, risk analysis and evaluation methods can be debated and resolved in that process. Therefore, we decline to acknowledge the IRP 2004 Action Plan and request parties provide comments within the context of the RFP approval process to ensure that the concerns raised in this docket are brought forward in that docket (No. 05-035-47).[3]

Comments on the RFP were filed August 23, 2005.

On September 2, 2005, PacifiCorp requested a 30-day delay in the RFP procedural schedule, noting that new assumptions with regard to load curtailment renewals and qualifying facility (QF) contracts appeared to reduce or delay the need for the 2009 resource. The 30-day delay would allow the Company time to evaluate these changes. The Commission issued the Revised Scheduling Order September 12.

On October 20, 2005 the Company filed to suspend its procedural schedule in the RFP docket until the *Update* was completed. The Company expected the type, timing, and magnitude of the expansion plan to change. The Commission therefore issued a “Notice of Suspended Schedule” October 21 in combination with a “Notice of a Scheduling Conference.”

PacifiCorp filed the *IRP 2004 Update* on November 4, 2005. The Company indicated that the *Update* was informational only.

A new schedule for the RFP docket was determined in January 2006. The schedule included a March 6 technical conference on IGCC and an April 3 technical conference on costs/timeline/alternative with additional activities culminating in July hearings, if necessary. The first two technical conferences were held as scheduled. However during the April 3 conference, parties discussed a delay to allow PacifiCorp and its new owner an opportunity to discuss the many issues associated with PacifiCorp’s resource acquisition strategy.

On April 19, 2006, PacifiCorp filed a “Motion to Extend Procedural Schedule.” The proposed schedule includes a May 9 Technical Conference with Pre-Draft Presentations

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[3] Public Service Commission of Utah, Report and Order, *In the Matter of the Acknowledgement of PacifiCorp’s Integrated Resource Plan 2004*, Docket No. 05-2035-01, July 21, 2005, p. 20.

to Bidders and Stakeholders in June. PacifiCorp will file its Draft RFP on July 11, 2006 with additional activities culminating in September hearings, if necessary.

In anticipation of activity in the RFP docket, and to comply with the requirement of the Procurement Act that the Commission "review and provide guidance" to the utility on any action plan developed as part of an IRP, the Commission issued a request for comments in this docket: Docket 05-2035-01 on February 22, 2006. Specifically, the Commission asked parties to comment on "the appropriateness of inputs, assumptions, analysis and conclusions of the 2004 IRP Update report including its updated action plan" and to "recommend an appropriate process for integrating comments on this 2004 IRP Action Plan Update with the pending solicitation for significant energy resources in Docket No. 05-035-47."[4] The Commission requested the comments by March 31 but approved two requests for time extensions. The comments are now due May 5.

These comments are in response to the Commission request.

3 ISSUE AND DISCUSSION

The Committee wishes to begin by expressing appreciation to the Company for its responsiveness to stakeholder concerns which resulted in an improved action plan. We had remarked in our *IRP 2004* comments that a defect of the Company approach in hand-building portfolios was that it left the Company short of time to use the information it had garnered from its analysis to improve upon its portfolio building. In this *Update*, PacifiCorp appears to have used lessons learned from *IRP 2004*. We appreciate the improvements the Company continues to make.

We do not believe, however, that the *Update* has identified a least cost, least risk portfolio. Our first concern with the Update Portfolio is that the current plan does not add enough length nor effectively evaluate the range of expansion options available. Our primary concern with this IRP is its unevaluated market risk which contravenes the Standards and Guidelines and past Commission orders. To address both issues will require evaluation of additional transmission and additional and/or larger wind and thermal resources.

We do not take issue with the 2012 resource selection. We do, however, find it unfortunate that the identified resource will not be coming on line in 2007 as originally targeted by *IRP 2003*, the only IRP and action plan acknowledged by this Commission since January 13, 1997.

3.1 Summary of CCS Comments on IRP 2004

The Committee's *IRP 2004* comments made two main points in addition to raising a number of subsidiary concerns. First, our analysis indicated the results were biased toward gas-fired resources. We were therefore concerned that the portfolio of resources identified as optimal by *IRP 2004*, the Preferred Portfolio, was weighted too heavily toward gas-fired additions. We presented a number of modeling issues in support of this contention. Second, we expressed our continuing alarm with the volume of shorter-term

[4] Public Service Commission of Utah, Request for Comments, *In the Matter of the Acknowledgement of PacifiCorp Integrated Resource Plan 2004*, Docket No. 05-2035-01, February 22, 2006, p. 1.

market transactions included as an existing resource to meet firm obligation. We contended that this risk had not been evaluated. Finally, we noted that the Company had not evaluated transmission options on an equal basis with other supply side options or included transmission upgrades in the *IRP 2004* modeling process as required by the Commission in its *IRP 2003* Order. We concluded by urging the Company to develop a long-run vision linked to wind and coal gasification rather than meeting incremental load with market and gas-fired resources.

As a result of our analysis, we questioned whether the identified portfolio of resources, the Preferred Portfolio, was least cost, least risk. With respect to our concern that the Portfolio was weighted too heavily toward gas-fired resources, we were particularly concerned with the addition of the first Combined Cycle Combustion Turbine (CCCT) addition in 2009 which required immediate action. We had requested further analysis from the Company on the need for the 2009 CCCT, which we had not yet received at the time we submitted our comments.[5] We therefore asked the Commission to withhold acknowledgement until the analysis was submitted and analyzed. We also requested that the Commission direct the Company to evaluate the market risk of the front-office transactions and any indexed purchases, and we requested that the Commission withhold its acknowledgement until it had received that information and made a determination regarding who should bear the risk. The Commission did not wait. It acknowledged the IRP but not the action plan.

3.2 IRP Update Portfolio and Preferred Portfolio Comparison

The expansion plan identified as least cost, least risk in the *Update* differs significantly from the portfolio identified by *IRP 2004* in type, timing, and magnitude. For clarity in communication, we will refer to the portfolio identified by the *Update* as the Update Portfolio; we will continue to refer to the portfolio identified by *IRP 2004* as the Preferred Portfolio.

The Update Portfolio includes the following 2,113 MW in additions over the next ten years:

- 2008: 44 MW DSM added to both east and west sides of the system (total of 88);
- 2010: (300 MW) Path C transmission upgrade;[6]
- 2011: 100 MW west-side seasonal purchase;
- 2012: 575 MW east-side coal plant;
- 2012: 561 MW west-side CCCT;[7]

[5] We recognized a system need arising in 2009. However, we requested an evaluation of two alternatives to bridge the two-year gap until 2011 when the Hunter 4 coal plant should have been able to come on line. At the time we made our request, a PacifiCorp employee indicated that a 2011 on-line date was no longer achievable making our request moot. A description of our alternative portfolios is provided on page 18 of our *IRP 2004* comments.

[6] The upgrade does not increase the generating capacity of the system; it changes the way the system can be operated to meet system peak. Therefore the upgrade is not counted when determining the size of the portfolio capacity addition.

[7] The assumed capacity of the west side CCCT decreased in the *Update* from 586 MW to 561 MW as a result of assuming a higher elevation for the siting of the CCCT than was assumed in *IRP 2004*. Higher altitudes decrease plant efficiency.

- 2013: 100 MW west-side seasonal purchase;
- 2013: 44 (45) MW of DSM added to both east and west sides (89 in total);
- 2014: 100 MW west-side seasonal purchase;
- 2014: 500 MW coal-fired addition in Wyoming (east-side location, west control area).

The Preferred Portfolio identified by *IRP 2004* included the following 2,806 MW of additions over the next 10 years:

- 2008: 44 MW DSM added to both east and west sides of the system (total of 88);
- 2009: 525 MW east-side CCCT;
- 2011: 575 MW east-side coal unit;
- 2012: 586 MW west-side CCCT;
- 2013: 560 MW CCCT located in Utah;
- 2014: 383 MW coal unit located in Wyoming (east-side location, west control area);
- 2013: 44 (45) MW of DSM added to both east and west sides (89 in total).

The Update Portfolio modifies the Preferred Portfolio in the following way. It completely removes two gas units that were to be located on the east side. It defers the first east-side coal unit by one year, and it increases the size of the later coal addition by 117 MW. It adds a 300 MW transmission upgrade which allows additional power from the Bridger Wyoming plant to meet Utah load. Finally, it adds 300 MW of peaking seasonal purchases on the west side to compensate for the change in system operation. DSM and planned resources remain unaltered: 177 MW DSM; 1200 MW of front office transactions; 100 MW of new QF contracts; and 1400 MW of renewables, primarily wind.

The effects of the changes are summarized below:

- Portfolio size reduced by 693 MW (2,113 MW vs. 2,806 MW);
- Gas fired resource capacity reduced by 1,110 MW (561 MW vs. 1671 MW);
- Coal fired resource capacity increased by 117 MW (1075 MW vs. 958 MW);
- Seasonal purchases increased by 300 MW (300 MW vs. 0 MW);
- Transmission upgrade added, allowing an increase in control-area transfers of 300 MW beginning in 2010.

Thus, the Update Portfolio significantly slashes gas-fired additions while slightly increasing coal-fired additions thereby reducing gas price risk. It adds a transmission upgrade which provides PacifiCorp greater operational flexibility. However, it increases market risk by reducing the overall portfolio size and adding an additional market component.

3.3 Impact and Evaluation of Modeling Assumptions

Revised assumptions in four areas provide the rationale for the significant change in the expansion plan as outlined above: a revised load and resource balance resulting from altered resource assumptions (load assumptions remain unchanged); the MidAmerican Energy Holding Company (MEHC) commitment to upgrade Path C; updated price and cost assumptions; and a changed method for treating depreciated plant. All other planning assumptions used in *IRP 2004* remain the same. In this section we will address the impact and reasonableness of these changes.

3.3.1 Resource Assumptions and the Load and Resource Balance

The load and resource balance is critical to determining the size and timing of the resource need. The Company's resource position changed significantly between *IRP 2004* and its update as a result of newly signed procurement contracts and changed resource assumptions. The load forecast was unaltered.

PacifiCorp's updated analysis indicates it now has adequate resources until 2011 when it is short of meeting a 15% planning margin by 175 MW. This shortage climbs sharply to 1,096 MW in 2012, to 2,024 MW in 2014, and to 2,352 MW in 2015. See CCS Exhibit A.[8]

In *IRP 2004*, PacifiCorp first failed to meet its 15% planning margin in 2008 when a shortage of 73 MW appeared. The size of the shortage grew steadily thereafter, increasing to 942 MW in 2011, to 1,753 MW in 2012, and to 2,777 MW in 2014. See CCS Exhibit B.[9]

Procurements completed between the filing of *IRP 2004* and the *Update* add 354 MW of power. Approximately 245 MW contribute to peak capacity. Procurements include:

- 164 MW of QF power. Of that 107 MW is firm;
- 65 MW of renewables from procuring Wolverine Creek in southeast Idaho. 13 MW of this contributes to meeting peak requirements;
- 125 MW of other firm characteristics.[10]

Changed resource assumptions add approximately 679 MW of capacity. The bulk of the increase is nearly equally split between an altered method for counting hydro and an assumption extending certain contracts past their current expiration dates.

- Hydro: Two changes affect hydro. Hydro flows are assumed to be 7% lower over the next 20 years due to changes in river operation. The magnitude of this effect is not quantified in the *Update* report.

  How hydro is counted is also changed. Previously the capacity contribution of hydro had been based on expected flows. However, for the update, hydro resource capacities are counted "by the maximum capacity that is operationally sustainable for one hour before reserves." This approach is consistent with how WECC is requesting its control areas to report hydro capacity. The effect of this counting change contributes an average of 329 MW to the system position.

- DSM increased by an average of 28 MW due to the addition of the Utah Load Lightener program.

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[8] CCS Exhibit A reproduces the load and resource balance table, Table B.2, from page 66 of the Update. PacifiCorp, *Integrated Resource Plan 2004 Update,* November 11, 2005, p 66.

[9] CCS Exhibit B reproduces the load and resource balance table, Table F.1, from page 81 of the *IRP 2004 Appendix*. PacifiCorp, *Integrated Resource Plan 2004 Appendix*, January 20, 2005, p 81.

[10] Page 9 of the *Update* states that new procurements total 354 MW of capacity. Since 164 MW are QFs and 65 MW are renewables, the Committee identified 125 MW as "other." In stating that 245 MW contribute to peak capacity, we are assuming that the 125 MW of "other" are firm transactions.

- QF contracts are assumed to continue past their expiration date. This adds an average of 137 MW to the system position.[11]
- Interruptible contracts are also assumed to continue past their expiration date. This adds an average of 185 MW.[12]

When completed procurements and the additions resulting from changes in resource assumptions are added together, the increase in resources available to meet the system peak approaches an average of 924 MW. Offsetting these increases were decreases in planned front office transactions. As a result of the above changes, and reconciliation with the Grid Model, the improvement in the system position ranged from 383 MW in 2007 to 753 MW in 2014. The year-by-year change is displayed in the bottom row of CCS Exhibit C.[13]

Since procurement is an ongoing process and the new DSM program is relatively small, the two significant drivers of the changed resource position are the changed manner in which hydro is counted and the decision to assume that QF and interruptible contracts are extended which together accounts for an average increase of 651 MW.

In assessing whether these changes are reasonable, we would like to make a distinction between power availability/reliability and economically priced power. If the only criterion in assessing a load and resource balance is whether the power could be available at the any price, then the Committee believes these assumptions are reasonable. We expect that enough hydro will be available in the peak hour to keep the lights on, that interruptible customers will continue to have the ability to curtail load, and that the QF facilities will continue to have the ability to provide power that they could sell to PacifiCorp (assuming they have adequate natural gas resources).

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[11] Assumption change suggested by UAE.

[12] Assumption change suggested by UAE.

[13] CCS Exhibit C displays the change in the system position between *IRP 2004* and its *Update*. It was created from the load and resource balance tables provided in the two reports. CCS Exhibit B reproduces Table F.1, the load and resource balance table from page 81 of the *IRP 2004 Appendix*. CCS Exhibit A reproduces Table B.2, the load and resource balance table from page 66 of the *Update*. Exhibit C is the result of subtracting Exhibit B from Exhibit A. The Committee followed the approach of the Company in adjusting the fiscal years displayed in Table F.1 to calendar years by moving the fiscal year back. Thus, as an example, fiscal year 2009 becomes calendar year 2008.

While the line by line changes displayed in Exhibit C do not always match the text or the values provided in Table A.3 (Annual Maximum Megawatts Per Contract Per Year) from pages 54-55 of the *Update*, through extensive communication with the Company, including three telephone conference calls and responses to data requests, the Committee has determined that the year-by-year system position displayed in Exhibit C closely portrays the effect of changed assumptions. A question remains regarding the size of a sale that would reduce the system position by 70 MW.

As an example of the reason the Committee conducted an extensive reconciliation, the text states that there was no change in thermal resources between the two IRPs while Exhibit C shows an east side thermal resource decline of 113 MW. The explanation is the reclassification of the Desert Power contract (90 MW) from the thermal category to the QF category and a reclassification of the Blundell geothermal plant (23 MW) from the thermal category to the renewables category. On the west side, part of the large increase in hydro and the decrease in purchases results from moving the Mid-C contracts from purchases to hydro.

However, if the criteria include meeting the load in an economical fashion, then the Committee is concerned by the increased cost exposure should a low hydro year result in increased spot market purchases in hours other than the peak, interruptible customers exercise market power in contract negotiations, or qualifying facilities discontinue providing power to PacifiCorp for any of a number of reasons. Under these circumstances while the power might be available at the “right price,” the Committee is concerned by the possible price tag of maintaining reliability.

Finally, if the Company met its load obligations without relying on significant shorter-term purchases, the Committee would feel more comfortable in the Company’s ability to balance load in an economical manner should these assumptions prove to have been ill advised.[14]

3.3.2 Thermal Plant Retirement

For the *Update*, PacifiCorp changed how it models thermal retirements. Instead of retiring plants at the end of their depreciable lives, PacifiCorp used life extension as a proxy for a new resource. This assumption did not change the load and resource balance over the planning period; it did reduce the number of market purchases and the volume of energy not served in the outer years.[15]

The Committee approves of this modeling improvement and commends PacifiCorp for its responsiveness to stakeholder input. While the modeling assumption does not directly comply with a Commission directive issued in its Resource and Market Planning Process (RAMPP)-5 Order to retire plants at the end of their depreciable life, the Committee believes the Company’s new modeling practice is in alignment with the Commission’s intent to assure that the load and resource balance is correctly calculated and that new resource additions are properly evaluated.[16]

In our *IRP 2004* comments, the Committee questioned whether resources should be assumed to be retired at the end of their depreciable lives. We suggested that life extension should be an IRP determination. The IRP should include the cost of life extension as a resource to be chosen on an equal basis with other resource options. It appears to us that this best assures that IRP modeling reflects least cost, least risk planning and is consistent with actual practice.[17]

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[14] RAMPP-5, issued December 1997, demonstrates the criticality of the load and resource balance assumptions. Given the assumptions then used, the IRP indicated no need for additional capacity or energy until 2012. Since then nearly 1200 MW of thermal resources have been acquired: Gadsby, Current Creek and Lakeside, and this IRP indicates an additional need of nearly 1100 MW by 2012. Thus, the assessed need in RAMPP-5 was off by nearly 2300 MW.

[15] The life of Little Mountain was extended from 2006 until 2012 increasing the load and resource balance by 14 MW. However this decision was not directly related to the general modeling change.

[16] A major issue in RAMPP-5 (and RAMPP-6) was underforecasting system need which then led the deferral of resource additions. Requiring PacifiCorp to retire plants in a manner that was consistent with its depreciation studies was a step toward better load and resource balance forecasting and provided consistency with other regulatory dockets. PacifiCorp followed the Commission directive to retire plants at the end of their depreciable lives in RAMPP-6, *IRP 2003* and *IRP 2004*.

[17] In reviewing past IRP Orders as part of the comment process, the Committee recently noticed that a similar point had been made over a decade ago in comments to the Commission regarding RAMPP 2.

As we understand it, the Company's modeling approach in the *Update* is responsive to our suggestion. The following language is taken from a response to OCA 1st Data Request 1.9 which the Committee received in response to an informal request for information.

> The Company's 2004 IRP Update was used to develop a planned resource portfolio for the years 2006-2015. Since no thermal plant retirements are expected to occur during this 10-year planning horizon (with the exception of the Little Mountain gas turbine plant), no economic evaluations had to be made to determine whether life extensions were more or less efficient or cost effective as resource replacement.
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> As part of the economic valuation of different portfolios in the 2004 IRP Update, the Company computed a Present Value Revenue Requirement (PVRR) over a 20-year period for each portfolio. This required assumptions to be made through 2025. Since most of the Company's thermal plants retire prior to 2025, the Company had to make a modeling assumption as to what would happen post-retirement. The choices were: 1) do nothing, which would result in the production cost model buying all future requirements from the market and when the market was exhausted, not serving load; 2) assume that new plants or market stations are added in some manner throughout the system to replace lost plants; or 3) assume plant extensions as a proxy for resource replacement. The Company chose to assume the latter in the 2004 IRP update, with the disclaimer:
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>> *"Note this new assumption is not meant to presume a particular replacement strategy based on economics or regulatory factors, or to establish different extension dates from what was reported in PacifiCorp's 2002 Depreciation Study." (2004 IRP Update, page 10)*[18]

The modeling change has an interesting effect on the PVRR of all portfolios evaluated in the *Update*. Because the modified modeling approach meets loads in the later years with "retired" coal resources instead of through spot market purchases, forecast emissions levels for all portfolios were in excess of year 2000 actuals, so no portfolio benefited from emissions credits. This is a major change from the results in *IRP 2004* when all but one portfolio was forecast to emit fewer pollutants than did PacifiCorp's fleet in the year 2000.

It does not appear to the Committee that either IRP accurately portrays future emission levels. *IRP 2004* underestimates emissions, since it is unlikely that PacifiCorp will meet its obligations strictly through market purchases, while the *Update* overestimates emissions, since the addition of environmental control technology would be necessary to extend the lives of these coal plants, reducing emissions from current levels.

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[18] PacifiCorp response to OCA 1st Data Request 1.9, Oregon Docket 20000-220-EA-05, February 14, 2006.

3.3.3 Path C Upgrade

The Committee applauds PacifiCorp's inclusion of a transmission upgrade as a resource option in the portfolio building and evaluation process and its selection as part of the Update Portfolio. PacifiCorp's analysis demonstrates that the Path C upgrade is cost effective. The upgrade better integrates PacifiCorp's two control areas, increasing operational flexibility and presumably reliability.

However, because no alternatively sized upgrades were evaluated, the Committee cannot validate that 300 MW is the optimal size. As we discuss below, it appears to us that a larger upgrade may be necessary to better integrate the system and access additional Wyoming wind and coal resources which are needed as soon as possible, given what we perceive to be the market risk of the current position, and we urge evaluation of a larger upgrade and additional transmission additions in the current IRP process.

3.3.4 Price and Cost updates

In our *IRP 2004* comments, the Committee took issue with the low gas and market price forecasts and with certain cost assumptions included in the Company's *IRP 2004* analysis, all of which we thought biased the results toward gas-fired and market resources.

The Committee is generally satisfied with the price forecasts and cost estimates used in the *Update*. However, we note that the bias in favor of smaller gas-fired additions over base load plants has not been fully removed.[19]

3.3.5 Modeling Assumption Conclusion

The Committee generally supports the approach taken by the Company in conducting the *Update*. The natural gas price and market price forecasts better reflect current knowledge, and the transmission upgrade is demonstrated to be cost effective. Our main hesitation is in evaluating the changed resource assumptions that significantly alter the load and resource balance. While each assumption considered alone does not appear unreasonable, we are disturbed by the increased unevaluated market risk.

In addition, the Committee is uncomfortable realizing that the Company does not necessarily use the same assumptions for ratemaking as it does for planning. For example, PacifiCorp assumes in the current rate case that no further energy will be purchased from certain QFs following the expiration of their current contracts. In reply to a Division of Public Utilities (Division) data request inquiring why they made such an assumption, PacifiCorp says:

> Regardless of the company's obligation under PURPA, the QF does not have the obligation to sell the generation to the Company. The QF's options include 1) selling to the company, 2) taking their generation to market (excluding Kennecott), 3) using the generation to serve its load, or 4) not generating. Given the QF's preference for a one year contract, it is

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[19] See Committee of Consumer Services, *Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2004*, Docket No. 05-2035-01, April 25, pp. 13-16.

> reasonable to assume that the company does not have a call upon their generation. [20]

The Committee is concerned by the use of different assumptions in different forums, particularly planning and ratemaking. It appears to us that planning and ratemaking assumptions should be consistent, increasing confidence that PacifiCorp stands behind its assumptions, since it would bear a share of the cost of being wrong. Furthermore, maintaining consistency reduces the temptation to choose end-driven assumptions rather than assumptions that most effectively model actual operation and risk.

Therefore, the Committee recommends that the Commission direct the Company to use the same assumptions for ratemaking that it does for planning. If different assumptions are used in the ratemaking process, they should be justified. By requiring consistency between planning and ratemaking, the Committee believes the Commission and stakeholders can have greater confidence in the Company's planning assumptions and IRP modeling.

The Update Portfolio appears to be superior to the Preferred Portfolio. It identifies a coal-fired resource as the next major resource addition, reduces the ratio of gas-fired to coal-fired acquisitions, and adds a transmission upgrade. These changes reduce the gas price risk inherent in the previous action plan and better integrate the PacifiCorp system. However, the *Update* achieves these benefits by reducing the overall portfolio size and adding a seasonal purchase, thereby increasing market price risk. As we show below, the seasonal purchase is modeled as riskless, and the potential cost of spot market purchases has not been fully assessed.

Therefore, stating that the Update Portfolio appears superior to the Preferred Portfolio is not synonymous with determining that it is least cost, least risk. We address additional issues below.

3.4 Evaluation of Update Portfolio as Least Cost, Least Risk

The Committee notes that an IRP update is not necessarily intended to identify an optimal portfolio but rather to signal the Commission of changed circumstances. However, the unique circumstances surrounding the *IRP 2004 Update* require that it be evaluated in a rigorous manner.

3.4.1 Load and Resource Balance with Update Portfolio

CCS Exhibit D displays PacifiCorp's load and resource balance with the inclusion of the Update Portfolio resources. As one can see, the new portfolio does not fully meet the need identified by the *Update*. Exhibit D demonstrates that the system remains 239 MW short in 2015 even after the addition of the Update Portfolio.

The system shortage results from an eastern shortage that overwhelms the added resources in the west. The planning reserve margin in the western control area exceeds 27% in the last two years of the planning horizon as a result of the addition of a 561 MW CCCT in 2012 and the 500 MW unit at Bridger in 2014 while the eastern control area's planning reserve margin falls as low as 6.6% in 2015.

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[20] Response to DPU Data Request 4.5, Docket No. 06-035-21, April 17, 2006.

The eastern control area is 361 MW short in 2014 while the west control area is 450 MW long. In 2015, the eastern shortage grows to 709 MW while the western surplus is but 470 MW leaving the system short. We also note that the eastern control area is 160 MW short of a 15% planning reserve margin in 2011 prior to the addition of the 2012 resource while the west control area is 173 MW long.

To address the east/west imbalance, the Committee recommends that a larger Path C expansion and other transmission upgrades better integrating the PacifiCorp system be considered.

To address the insufficiency in the later years, the Committee recommends that a larger 2014 addition at Bridger, more wind and additional transmission be considered.

3.4.2 Unevaluated Portfolio Options

Portfolio Q, considered as part of *IRP 2004,* included two units at the Bridger site. The Committee suggests that this option be evaluated.

The 1400 MW of wind included as a planned resource was determined during *IRP 2003*. Since then, gas prices, market prices, and turbine costs have all changed significantly. The Committee recommends that PacifiCorp revisit the optimal size of wind. The correct amount of wind could be greater or smaller depending on whether the free fuel aspect of wind which mitigates high gas prices outweighs the higher capital cost of wind turbines. We expect that more rather than less wind would be shown to be cost effective.

An IC Aero should be considered as an alternative to seasonal purchases.

In our past two sets of comments, the Committee has urged consideration of realistic transmission alternatives, including analysis of incremental additions and upgrades that are modeled in a comparable manner with generation additions.[21]

In its Order acknowledging *IRP 2003*, the Commission directed the Company to "evaluate transmission alternatives on a consistent and comparable basis with generation alternatives, include analysis of transmission upgrades and improve transmission analysis…"[22]

IRP 2004 took the first step by adding additional transmission to access Bridger power. The *Update* has taken a second step by evaluating the Path C Upgrade. The Committee urges the Company to take the plunge and model transmission "on a consistent and comparable basis with generation alternatives" as directed by the Commission.

As part of the MEHC acquisition proceedings, the Committee reviewed a number of transmission upgrades and additions identified by PacifiCorp's Transmission Group. The

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[21] See: Committee of Consumer Services, *Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2003*, Docket No. 03-2035-01, March 31, p. 20-21; and Committee of Consumer Services, *Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2004*, Docket No. 05-2035-01, April 25, p. 20.

[22] Public Service Commission of Utah, Report and Order, *In the Matter of the Acknowledgement of PacifiCorp's Integrated Resource Plan 2003*, Docket No. 03-2035-01, May 30, 2003, p. 13.

Committee recommends that these options be included in the current IRP modeling process.

3.4.3 Evaluation of Nonfirm Transmission

The east control area shortages noted above in the section titled "Load and Resource Balance with Update Portfolio" raise the question of whether PacifiCorp faces a reliability or cost risk in 2011, 2014 and 2015 in its east control area since the IRP modeling already takes into account firm transmission capability. We believe the answer must lie in the availability of nonfirm transmission to use western surplus to meet eastern load.

The Committee requested 48 months of historical nonfirm transmission activity in the format ordered by the Commission in the Avoided Cost Docket No. 03-035-14.[23] In response, the Company provided data for 2004 and 2005. It explained that prior to those years it was not required by FERC to track such data. We can not tell from our review of the response whether there is adequate nonfirm transmission available or not.

However, if PacifiCorp does use nonfirm transmission on a regular basis and is planning to meet the east control area need in this manner, this does call into question whether the control area transfer assumptions are modeled correctly for determining control area load and resource balance and system dispatch.

The Committee recommends that the Commission direct PacifiCorp to work with its stakeholders to explore the costs, risks, and benefits of modeling some quantity of nonfirm transmission as available for IRP modeling. The Commission may want to create a Utah specific taskforce to evaluate this issue for broader application.

We further note that including some non-firm transmission would reduce the modeling bias against baseload plants and resource length by better accounting for the benefits of off-system sales.

If nonfirm transmission from west to east is not available on a regular basis, then the east control area is quite short, particularly in 2014 and 2015.

3.4.4 Planned Resources

Beginning with *IRP 2004* and continuing with the *Update*, PacifiCorp initiated a new method for determining its load and resource balance. It began counting resources that it plans to acquire as part of its ongoing procurement activities, as well as resources that it currently owns or for which it has signed long-term contracts, as firm resources available to meet projected load obligations.

Resources that the Company already owns, is in the process of building, or for which it holds signed contracts are termed "existing resources." Resources that the Company has not yet acquired but plans to acquire through shorter-term procurement are termed "planned resources." The Company includes both existing and planned resources as firm in assessing the load and resource balance which indicates the size and timing of resource need. Both categories of resources are modeled as existing when evaluating the costs and risks of alternative portfolios.

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[23] CCS Data Request 5.2, Docket No. 05-2035-01, April 7, 2006

3.4.4.1 Description of Planned Resources

Planned resources include three categories: (1) renewables; (2) QF contracts; and (3) front office transactions.

The renewable category is comprised of wind resources identified by *IRP 2003*. Its size was not reevaluated in *IRP 2004* or the *Update*.

Qualifying facilities are renewable or cogeneration facilities that meet certain federal guidelines. The utility is obligated to purchase the output of QFs at the Company's avoided cost. The size and availability of the purchase are determined by the seller.

Front office transactions are layered shorter-term standard products. The Company used historical availability to determine the size of this resource. Front office transactions are "intended to bridge the gap between reliance on spot market activity and long-term build or buy commitments in order to balance the system."[24] *IRP 2004* describes them this way:

> Front Office Transactions are usually standard products, such as Heavy Load Hour (HLH), Light Load Hour (LLH), and/or daily HLH call options (the right to buy or 'call' energy at a 'strike' price) and typically rely on standard enabling agreements as a contracting vehicle…The prices of Front Office Transactions are determined at the time of the transaction….An optimal mix of these purchases would include a range in terms for these transactions.
>
> Solicitations for Front Office Transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.[25]

Thus, the 1200 MW of front office transactions consist of two products: a flat annual product and a summer peak seasonal product. *IRP 2004* and its *Update* include 500 MW of an annual 7 x 24 product on the west side of the system and 700 MW of summer (third quarter) HLH products on the east side. Two-hundred MW are purchased at Mona and 500 MW at 4-Corners.

The *Update* includes:
- 1300 MW of renewables,
- 100 MW of new QF contracts, and
- 1200 MW of front office transactions.

IRP 2004 included:
- 1400 MW of renewables,
- 100 MW of QF contracts, and
- 1200 MW of front office transactions.

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[24] PacifiCorp, *Integrated Resource Plan 2004*, January 20, p. 52.

[25] Ibid.

The 100 MW reduction in the size of the wind resource from *IRP 2004* to the *Update* reflects PacifiCorp's procurement of the Wolverine Creek wind project in Southeast Idaho.[26] As planned resources are firmed and contracts signed, they cease to be "planned" and are categorized as "existing." Thus, one generally expects an indirect relationship between planned resources and existing resources as is seen in the case of wind. However, this relationship is not apparent with the QF contracts.

PacifiCorp recently procured more than 100 MW of QF power in its eastern control area; however, it continues to include 100 MW of additional QF contracts as a planned resource rather than reducing planned resources by an equivalent amount. In response to a CCS data request asking why planned QF resources did not decline on the east side when existing QF power had increased significantly, PacifiCorp responded "it was assumed that there are 100 MW of additional QF resources in Utah beyond what had been signed at the time of the 2004 IRP Update."[27] The Committee has not validated this assumption. Whether this power will be firmed or the need met some other way is yet to be seen.

3.4.4.2 Issues associated with the inclusion of planned resources as firm in determining load and resource balance:

The Committee notes several significant issues associated with the inclusion of planned resources as firm in determining the load and resource balance. The first arises if resources are not procured as expected.

For example, *IRP 2003*, filed in January of 2003, identified 1400 MW of wind resource that is included in *IRP 2004* and the *Update* as a planned resource that the Company is counting on to meet its firm load obligation.[28] At this point in time, the Company has not been as successful as anticipated in procuring sufficient wind. It has procured but 65 MW of the 1400 MW target.

When resources are not procured as expected, the load and resource balance projection will understate the resource need, and obligations will have to be met some other way, presumably through spot market transactions, increasing market exposure. However, front office transactions are directly related to spot transactions. So if hedging opportunities or seasonal products lose liquidity, extraordinary prices and reliability concerns may result.

As an example of how the load and resource balance is affected by planned resources, CCS Exhibit E displays PacifiCorp's load and resource balance with the front office transactions removed. System need first appears in 2008 when the system is short of meeting a 15% planning reserve margin by 309 MW. The shortage grows to 602 MW in 2009, 1000 MW in 2010, and 1,375 MW in 2011. Most of this shortage appears on the east side of the system. In 2012 with the expiration of the BPA peaking contract, the west side becomes significantly deficit by 908 MW while the system deficit grows to

[26] The 65 MW addition is modeled as a 100 MW block.
[27] PacifiCorp, Response to CCS Data Request 4.8.b.iii, Docket No. 05-2035-01, March 31, 2006.

[28] 280 MW of the 1400 MW are counted as capacity to meet peak.

2,296 MW. The system shortage increases to more than 3,500 MW in 2015, the last year in the planning horizon.

CCS Exhibit F shows PacifiCorp's load and resource balance with the addition of the Update Portfolio but without the front office transactions. System shortages appear in 2008 and grow to 1,439 MW by 2015.

A second issue with the inclusion of planned resources as firm has to do with whether the size and timing of resources identified by past IRPs should be reevaluated to reflect current conditions. For example, as previously discussed wind turbine costs and market and gas prices have changed significantly since *IRP 2003*, calling into question whether the quantity of wind identified by *IRP 2003* is still applicable.

Finally, by modeling planned resources as existing, the risk of these resources is never evaluated in the current planning process. Their projected invariant costs are simply included in every modeling run, including the stochastic analysis as discussed below.

This is less of a concern for QF contracts whose costs are determined through a Commission determined formula and for wind resources which were originally chosen as part of an IRP that considered risk; however, for front office transactions this is particularly problematic.

The decision to include 1200 MW of front office transactions as a firm resource has never been subjected to analysis to determine its optimal size, and its risk has never been quantitatively evaluated.

The inclusion of these resources as firm without detailed risk analysis is a continuation of a business strategy that the Company undertook in the mid 1990s over considerable objection from most Utah stakeholders and in violation of this Commission's directives, and it continues today.

3.4.5 Risk Analysis

The Company introduced stochastic modeling in *IRP 2003*. Stochastic modeling assesses the risk that actual experience differs from basecase forecasts. The Company uses stochastic modeling to evaluate the performance of alternative portfolios in reducing these risks.

To understand the expected risk of a given portfolio, the Company makes 100 model runs in which critical components of the cost of a portfolio are allowed to vary from the base case assumptions. The variances allowed from the forecasts are based on historical deviations. Assumptions that are allowed to deviate include hydro availability, loads, fuel prices, market prices, and outages. The results of the 100 runs provide information that help asses the risk posed by a particular portfolio.

As with all modeling, stochastic analysis is only as good as its assumptions. The Committee contends that the stochastic analysis fails to fully capture the risk posed by spot market purchases and completely fails to address the risk posed by front office transactions, both seasonal and annual products, as a result of the modeling assumptions used.

3.4.5.1 Spot Market:

Stochastic modeling requires the inclusion of parameters that determine the extent of variation allowed from the basecase forecasts. PacifiCorp uses historical time periods to determine these parameters. Presumably, each parameter is determined using a time period that PacifiCorp believes appropriately captures the expected variation. For the gas and market price volatility parameters, the IRP used June 1, 2001 through May 31 2004.[29] While this period appears appropriate to capture volatility in the gas market, it entirely misses a period of significant volatility in the wholesale market that began May 28, 2000 and ended May 25, 2001.

As a result, the stochastic analysis under-assesses the risk of spot market activity. Therefore, the stochastic analysis will under appraise the expected cost of smaller portfolios that rely more heavily on this market.

3.4.5.2 Front Office Transactions:

As currently modeled, the front office transactions are without risk.

The seasonal purchases are modeled as must-run with an invariant price reflecting the forward price curve. So, the cost of 700 MW of resource is capped at the 20-year forward price curve over the entire 20-year planning horizon.

The annual 7x24 product is modeled as a call option with a strike price of $70/MWh. So the cost of up to 500 MW of resource is capped at $70/MWh over the entire 20-year planning period. The only decision the model makes is how much of this capped power to dispatch.

Based on discussions with Company personnel, we understand that he model first evaluates purchases from the spot market before considering purchases using the annual 7x24 call option product. As long as the spot market price is below $70/MWh, the model dispatches spot market power. When the spot market hits the strike price of $70/MWh, the model then dispatches up to 500 MW of power capped at $70/MWh. When the full 500 MW of the annual product has been used, the model then returns to the spot market. If insufficient power is available then unserved energy is recorded.

3.4.5.3 Update Portfolio

The Update Portfolio adds 300 MW of seasonal purchases on the west side beginning in 2011 to compensate for the change in operation resulting from the Path C upgrade. The seasonal purchases included in the Update Portfolio are no different from other seasonal purchases. They are a layered shorter-term market transaction modeled as a must run and priced at the forward price curve.

In effect, the Update Portfolio increases the size of the front office transactions to 1500 MW. Thus, as modeled, this portfolio resource, like all other front office transactions will be modeled with no risk.

As a result of how these products are modeled, the measured risk of a portfolio can be reduced by replacing thermal resources with purchases. However, while the measured

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[29] PacifiCorp, *Integrated Resource Plan 2004*, January 20, p. 52.

risk will decline, the actual risk may not. The Committee believes it is imperative that the risk of these transactions be properly evaluated.

3.4.6 Compliance with Utah Commission Directives Regarding Risk Analysis

As the above discussion demonstrates, the stochastic risk analysis does not capture the risk of the Company's market activity. The cost of hedging is capped throughout the 20-year planning horizon. The cost of seasonal purchases never varies from the forward price curve, and the cost of spot market activity is artificially limited by unrealistically small volatility parameters. The Committee does not believe that the assumptions that annual call options will be capped at $70 MWh, seasonal purchases will be capped at the current forward price curve, or spot market volatility will be limited to the volatility reflected in the June 1, 2001 to May 31, 2004 time period over the 20-year planning horizon constitute risk analysis.

It appears to the Committee that time has well demonstrated that the strategy of relying on the market to meet firm load obligations without evaluating its risk is mistaken. The market is not only volatile but increasingly expensive. And, as evidenced by its PCAM filing in Utah and similar filings in other states, the Company is aware of the growing risk and desires to free itself of the consequences of its decade-long strategy.

A common thread in the Committee's last four sets of comments to the Commission regarding PacifiCorp's IRP is our alarm over the magnitude of market risk inherent in the Company's acquisition strategy. We raised this concern in our RAMPP-6 comments, *IRP 2003* comments, *IRP 2004* comments, and we raise it here.

Beginning with RAMPP 5, Utah participants raised considerable concern with the Company's decision to rely on the spot market to meet its growing load obligation and its lack of risk analysis for this decision.[30] RAMPP-5 minutes indicate that Ken Powell of the Division, stated that if a majority of the utilities in the west pursued PacifiCorp's strategy of relying on the wholesale market to meet total load obligations rather than building, the surplus could disappear rapidly. Short-term prices could skyrocket. In response to the expressed concern, a company representative assured stakeholder participants that the Company would bear the risk of this business decision.[31] The Division recommended against acknowledgement of RAMPP-5 in part because of the Company's decision to meet long-term obligations with short-term purchases.[32]

In the RAMPP-6 process, Utah parties expressed increasing levels of frustration as the Company continued to under-forecast need and refused to evaluate what Utah

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[30] See: (1) Division of Public Utilities (DPU), *Recommendation of the Division of Public Utilities*, Into the Matter of the Acknowledgment of PacifiCorp Integrated Resource Plan (RAMPP-5), Docket No 97-035-11, June 18, 1998; (2) Committee of Consumer Services, *PacifiCorp's Integrated Resource plan, RAMPP-6*, Docket No. 98-2035-05, December 21, 2001; and (3) Division of Public Utilities, *In the matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan (RAMPP-6)*, Docket No. 98-2035, December 21, 2001. See also the LAW Fund Comments in these same dockets.

[31] See RAMPP-5 minutes.

[32] Division of Public Utilities (DPU), *Recommendation of the Division of Public Utilities*, Into the Matter of the Acknowledgment of PacifiCorp Integrated Resource Plan (RAMPP-5), Docket No 97-035-11, June 18, 1998, pp 7-8.

stakeholders considered to be the real risks. When the market strategy unraveled in the 2000-2001 timeframe and the risk turned into real dollars, the Company turned to customers to pay the bill.[33] And, the Company is now requesting a PCAM to shift this ongoing risk to customers.

The manner in which PacifiCorp models its decision to rely on the shorter term market to meet a significant portion of its load obligation has changed since RAMPPs 5 and 6, but the underlying business strategy remains unchanged. And, despite the sophisticated stochastic modeling introduced in *IRP 2003*, no IRP has evaluated this market risk.

The Standards and Guidelines and previous Commission orders clearly outline the requirement that the Company analyze the risk of various business strategies in its IRP.[34] As the Commission notes in one of its IRP orders, the purpose of these requirements is to protect customers from risky management decisions. The Company has repeatedly fallen short of meeting this directive.[35]

Despite Standards, Guidelines, Commission Orders, and stakeholders comments, the Company appears to have been unwilling to analyze the optimal size or evaluate the risk of short-term market transactions as part of its IRP, preferring to rely on it for a full 1500 MW of capacity to meet firm load.

The Committee once again recommends that the Commission direct the Company to explicitly analyze the optimal size of front office transactions given the risk/benefit tradeoff.

4 CONCLUSION

While the Update Portfolio improves upon the Preferred Portfolio, it is by no means optimal. The Update Portfolio is far too exposed to the market, the risk of which has not been evaluated, contravening the Standards and Guidelines and numerous Commission Orders.

For this reason, if the Commission determines to provide review and guidance to the Company through an acknowledgment order rather than through a memorandum, the Committee recommends that it not acknowledge the *Update* unless the order makes

[33] See the proceedings in Docket No. 01-035-01.

[34] For example, the Standards and Guidelines state on page 44 that the Company should include: “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.” On page 29 of its RAMPP-3 Order the Commission states “we direct the Company to provide a suitable risk analysis…” In its RAMPP-4 Order the Commission devotes all of page 13 to the issue. It states: “The Commission orders a more comprehensive risk analysis for future IRPs. Failure to do so will jeopardize acknowledgment. On page 10 of its RAMPP-5 Order the Commission “find[s] that a quantitative risk analysis must be performed in RAMPP-6 if that IRP is to qualify for Commission acknowledgement.”

[35] While we do not have the opportunity to fully develop this history at this time, we did detail some of this in our RAMPP-6 comments. See Committee of Consumer Services, *PacifiCorp’s Integrated Resource plan, RAMPP-6*, Docket No. 98-2035-05, December 21, 2001, pp. 5-7. See also DPU RAMPP 5 comments. Finally see Commission Orders in RAMPP-2, RAMPP-3, RAMPP-4, RAMPP-5, RAMPP-6, and *IRP 2003*. Docket No.: 90-2035-01, 94-2035-05, 96-2035-01, 97-2035-06, 98-2035-05, 03-2035-01.

clear that the Company will bear the risk of its exposed position or addresses outright in what forum this issue will be decided.

5 ASSESSMENT OF 2012 RESOURCE

The Committee's analysis supports the addition of the 2012 proxy coal plant at Hunter Utah. The Committee's analysis demonstrates that PacifiCorp requires additional firm stably priced power by as early as 2008. The Committee therefore believes the Company should move expeditiously to acquire this resource as quickly as possible and should consider a larger addition, earlier, if it is available through the solicitation process.

IRP 2003 sited in calendar year 2007 what is now the 2012 proxy coal plant at Hunter. The *IRP 2003 Update* slipped its timing to 2008. *IRP 2004* initially targeted 2010 for this same addition and then slipped the online date to 2011. The current IRP slips this proxy plant by still an additional year—a full five years past its acknowledged in-service date.

While we recognize that the Company may now be unable to build a coal-fired resource prior to the summer of 2012, power with similar characteristics might be available earlier through the solicitation process and, if so, should be considered.

To verify the cost effectiveness of an earlier and larger addition (should it be available), the Company could use its IRP tools to evaluate the size and timing of a coal-fired resource addition with the self-build lead-time constraint removed.

In IRP modeling, the IRP correctly limits consideration of resource alternatives to those alternatives that the Company can self-build. Therefore certain resource additions are constrained by lead time and site considerations. However, the solicitation process allows existing resources to compete with potential resources and resources in various stages of development, so such artificial constraints can be removed. To the extent that the timing of portfolio additions within an action plan results from self-build limitations rather than from economic/risk considerations, such constraints should be removed from the RFP modeling.

6 PROCESS RECOMENDATION

In its request for comments the Commission requested that parties "recommend an appropriate process for integrating comments on this 2004 IRP Action Plan Update with the pending solicitation for significant energy resources in Docket No. 05-035-47." The Commission made this request because the rulemaking that will govern the interaction between the IRP, its action plan, and the RFP process is not yet completed. Thus the Commission requests input as a onetime measure to address the unique situation engendered by the need to evaluate the *IRP 2004 Update* and integrate the conclusions from this evaluation with the pending RFP.

The Committee recommends that the Commission provide its review and guidance to the Company on the current action plan in the IRP docket as it always has done. It could do so in the form of a memorandum or as an acknowledgment order.[36]

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[36] Acknowledgment orders have generally provided review and guidance whether the IRP was acknowledged or not. Acknowledgment orders have been detailed and have provided specific feedback to the Company with compliments for what is being done well as well as numerous directives for

Since not all issues addressed in the IRP are germane to a given RFP, the Committee believes it is important to keep an active IRP docket, separate from the RFP docket and subject to the Commission promulgated Standards and Guidelines. For example, while our analysis of the *Update* supports the Company procuring the 2012 resource through the RFP docket, we have concerns with other aspects of the IRP that we will want addressed in the appropriate forum.

However, the IRP and the RFP dockets must be related in some manner so that information garnered in the IRP can be fed into the RFP. As an example of this need, our analysis of *IRP 2004* indicated that the 2009 resource identified as the next build option may not have been the right resource. This analysis then was directly applicable to the 2009 RFP.

For the pending RFP, Docket No. 05-035-47, the Committee recommends that comments received on the *Update* should be incorporated into the body of data and information to be considered in the solicitation and resource approval process.

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improvement. When an IRP has not been acknowledged the Company has been provided with well reasoned explanations.