State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: Public Service Commission of Utah

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Date: 25 April 2005

Subject: Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2004; Docket No. 05-2035-01

1 SUMMARY AND KEY RECOMMENDATIONS:

The Committee of Consumer Services (Committee) appreciates the opportunity to comment on PacifiCorp's Integrated Resource Plan (IRP). The Committee understands that the resource decisions PacifiCorp (Company) makes in the immediate future and its development of a long-run resource acquisition vision are vitally important to both its customers and shareholders. Such decisions will influence rates that customers pay for essential electricity services for years to come. In the same manner, regulatory views of how well PacifiCorp meets its obligation to provide least-cost, least-risk service to customers will impact shareholder returns.

The Committee compliments PacifiCorp on its current IRP. We commend PacifiCorp's IRP Team for the conduct of its responsive IRP process, comprehensive report, and fine risk analysis of its chosen portfolios. However, the Committee does not draw the same conclusions from the results of the Company's analyses. The Committee is additionally concerned that the risk of market purchases was not explicitly analyzed. Therefore we can not agree that the portfolio of proposed new resources termed the Preferred Portfolio is the least-cost, least-risk plan.

In particular, the Committee believes the Preferred Portfolio is weighted too heavily toward gas-fired resources. While there will be opportunity in the next IRP cycle to address the viability of later gas-fired additions and potential alternatives, such as a combination of Integrated Gasification Combined Cycle technology (IGCC) and wind resources, the Committee is particularly concerned with the addition of a third Combined Cycle Combustion Turbine (CCCT) on the east side of the system in fiscal year (FY) 2010, which requires commitments within the current Action Plan timeframe.

The Committee has carefully analyzed the information provided by the Company and has discovered at least two supply-side options that were not explicitly evaluated during the IRP process that meet the resource obligation in FY 2010, but do not commit the Company or its ratepayers to the cost of a CCCT. The Committee has requested that the Company analyze these two alternatives. Should either or both options prove superior, we would expect PacifiCorp to modify its Action Plan to reflect such an outcome. The Committee recommends that the Commission withhold acknowledgement until this information is provided and evaluated.

With regards to market additions, the Committee recommends that the Commission direct the Company to provide detailed information on the volume of indexed market purchase contracts and to conduct an explicit stochastic risk analysis on indexed long-term purchases and the 1200 megaWatts (MW) of short and intermediate term front office transactions that are included as existing resources. The Committee recommends that the Commission withhold acknowledgment until it better understands the risks associated with these transactions and determines either who should bear those risks or clarifies in what setting such a determination will be made.

Finally, comments, suggestions and additional recommendations on IRP 2004 are included in the context of addressing specific issues in Section 3 of this memorandum.

2 BACKGROUND

2.1 Procedural

PacifiCorp began the public phase of its eighth planning cycle in December of 2003. In all, PacifiCorp conducted eight public input meetings, four technical workshops and provided ten written responses to concerns raised during Public Input Meetings that PacifiCorp was either unable to answer during the meeting or simply had a difference of opinion with the participant raising the issue.

It filed *Integrated Resource Plan 2004* with the Public Service Commission of Utah (Commission) on 20 January 2005[1]. The comprehensive report consists of 191 pages with a 246 page technical appendix.

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[1] Technically, the integrated resource plans are due every other December. RAMPP 6 was due in December of 2000 although it was not filed until June 2001. Since the IRP is to be filed every other year with an update in the off year, the next IRP was due December of 2002. It was actually filed in January of 2003 and was thus named, IRP 2003, rather than IRP 2002. In this cycle, PacifiCorp has named its IRP with the year in which it was due.

The Commission issued a request for comments on 10 February, 2005. Comments were initially due 24 March 2005. However, three extensions have been requested and granted. Specifically, the Commission invited "parties to make comment on the appropriateness of the *IRP 2004* report and to make recommendations on whether the Commission should acknowledge the plan." These comments are submitted in response.

2.2 History of PacifiCorp's Resource Planning

While this is PacifiCorp's eighth planning cycle, it is only the second planning cycle since its planning function underwent a structural reorganization in late 2001 following the demise of the western market and the high power costs incurred by utilities, including PacifiCorp, that were on balance, buyers. In order to more closely align the formal resource planning process with actual business practice, the lines of authority were changed within the Company in late 2001. The planning process was moved into the Commercial and Trading arm of the Company from the Regulation department, and a new project team was formed. The new team conducted PacifiCorp's seventh IRP cycle, named *IRP 2003*.

PacifiCorp's first IRP was issued in November 1989 in response to the planning requirements of the Washington Utilities and Transportation Commission and the Oregon Public Utilities Commission. It was named "Resource and Market Planning Program 1", or RAMPP 1. On 21 February 1990, the Commission, in Docket 90-2035-01, directed the Company to file RAMPP 1 in Utah. In June 1992, the Commission issued its Order in the Docket, promulgating IRP Standards and Guidelines.

Since 1990, PacifiCorp has filed a total of eight IRPs with the Commission. While the Commission found the general approach of RAMPP 1 reasonable and acknowledged RAMPPs 2, 4, and the RAMPP 3 process, it withheld acknowledgment of the RAMPP 3 Action Plan and did not acknowledge either RAMPP 5 or RAMPP 6, filed in December 1997 and June 2001 respectively[2]. RAMPPs 5 and 6 were not acknowledged, at least in part, because of two deficiencies. First, the Company's strategic business plan appeared to be driving the assumptions and outputs of the IRP, rather than the IRP informing the business plan. Second, the Company had shifted its business strategy, from providing surplus power to the market to reliance on the market, without adequate market or risk analysis.

PacifiCorp entered the dysfunctional market period of early 2000 and 2001 vulnerable due to its past decisions to rely on the market and to sell its Centralia coal plant and mine. As a consequence of PacifiCorp's exposed position, and an outage at its Hunter plant, net power costs exploded, and this Commission, like other Commissions, did not pass on the full cost of power purchased during this timeframe to ratepayers. It was within this context of unacknowledged past IRPs, resource deficits, dysfunctional markets, and cost disallowances that the Company reorganized its planning process and conducted its seventh IRP cycle, termed *IRP 2003*.

[2] The Commission did not have an acknowledgement mechanism in place prior to its 1992 Order in Docket 90-2035-01, and so could not acknowledge RAMPP 1.

That IRP cycle differed from the Company's previous planning processes in name, corporate organization, modeling approach, and quality of the public process. It broke with the immediate past two RAMPP cycles in its apparent intent to acquire firm resources for customers. However, it did not fully break from the Committee's fundamental concern that the Company's business plan drove the IRP rather than the IRP informing the Company's business plan

In its 2004 comments to the Commission, the Committee recommended that the Commission acknowledge *IRP 2003* because of the Company's "apparent commitment" to acquire firm resources to meet customers' needs. However, the Committee informed the Commission that it appeared that strategic business concerns, particularly concerns for shareholder recovery, continued to influence the resource plan in ways that may not be in the public interest. The Committee's comments cited various examples including the treatment of transmission in the IRP which led it to its conclusion. The comments went on to say: "as a result, whether the current Action Plan meets the Utah IRP Standards and Guidelines for least-cost is not clear".

The Commission Order issued 30 May 2003 acknowledged *IRP 2003*, the predecessor to this IRP, but warned PacifiCorp to take heed of the filed comments and gave specific directives for the Company to follow. The Order stated:

> Specifically, with respect to the next IRP we direct the Company to develop a base case for analytical purposes,[3] use automatic resource addition logic unless evaluation proves it to be unreasonable, evaluate transmission alternative on a consistent and comparable basis with generation alternatives, include analysis of transmission upgrades and improve transmission analysis especially with respect to the RTO West paradigm, evaluate in greater detail the risk burden of alternative portfolios upon customers and shareholders. Finally, customer rate impact analysis should be included, greater detail on rate impact provided and impact on demand from rate change and rate design studied.

It is within this context that the Committee discusses the current IRP, *IRP 2004*.

3 DISCUSSION AND ISSUES

The Committee wishes to begin by complimenting PacifiCorp for producing a readable, understandable, and thorough report with clear explanations of the results of its analysis. While the Committee does not reach the same conclusions as PacifiCorp, the Committee appreciates the information provided. The stochastic risk analysis, in particular, is well done and especially helpful. The Committee also wishes to commend PacifiCorp on the

[3] The implication here is that the base case should include only known and measurable changes in the assumptions. The UAE comments to which this directive appears to have been responsive had stated that speculative assumptions such as planning margin, carbon taxes, and non-firm transmission availability should be modeled as sensitivities, not be included in the base case. And previous Commission orders had directed the Company to not use speculative assumptions such as load loss due to deregulation. This directive is in that same spirit.

conduct of its public process and its generally responsive approach to stakeholder requests.

IRP 2004 identifies a deficiency between existing resources and peak load requirements plus a 15% planning margin of 1 MW in FY 2006. The shortage grows to 2,777 MW by FY 2015. PacifiCorp identified Supply Side Portfolio E modified with Demand Side Management (DSM), which it calls the Preferred Portfolio, as its least cost plan to meet this gap.

The Preferred Portfolio adds a total of 2806 MW: 177 MW of DSM, 1,671 MW of CCCT, and 958 MW of pulverized coal. Seven hundred MW of shaped seasonal products and 500 MW of flat annual products are included in existing resources. In addition, 1400 MW of wind, 100 MW of Qualifying Facility (QF) production, and 131 MW of DSM identified by *IRP 2003* but not yet in service are included as existing resources. Exhibit One portrays PacifiCorp's load and resource balance with the planning assumptions that PacifiCorp included in its existing resources separately displayed.

For a number of analytical and methodological reasons developed below, the Committee does not believe the Company has produced the least-cost, least-risk plan.

3.1 Description of PacifiCorp's Analytical Approach used to conduct *IRP 2004*

In preparing *IRP 2004*, PacifiCorp continued to use, with some refinement, the basic analytical approach it developed in *IRP 2003*.

The Company did not complete the development of the Capacity Expansion Model (CEM), PacifiCorp's modeling tool with resource addition logic as directed by the Commission, in time for use in this IRP cycle.[4] While the Committee believes that the Company produced a viable body of analysis with the tools that it used, the Company was not able to conduct important sensitivity analysis easily or to provide a meaningful path analysis as required by the Standards and Guidelines. The Committee has been told by PacifiCorp staff that these shortcomings will be addressed in the next IRP cycle when the CEM is fully operational.

For descriptive purposes, the Company's analytical approach can be divided into five major stages: (1) Assumption Development and Resource Needs Assessment; (2) Portfolio Development; (3) Power Cost Simulations; (4) Risk Analysis; (5) Identification of the Preferred Portfolio.

3.1.1 Stage One: Assumption Development and Resource Needs Assessment

In the first stage, key assumptions such as natural gas prices, market prices, carbon dioxide tax credits, etc., are developed for use in a production cost model, and PacifiCorp's resource needs are assessed. PaciCorp's IRP staff of four coordinates with the many departments within PacifiCorp who actually develop the forecasts.

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[4] The Committee understands that communication between the vendor and PacifiCorp broke down as the result of turnover within the IRP staff of four. The individual handling the project development left PacifiCorp, and the handover of this project slipped through the cracks, delaying its launch. Therefore the tool was available for some limited analyses but was not available for portfolio building and sensitivity analysis.

The size and timing of PacifiCorp's resource need depends on anticipated loads as well as the resources available to meet those loads. In years when significant contracts expire or aging thermal resources are retired, the forecasted need will be much larger than in years when load growth is the only component contributing to resource need.

3.1.1.1 Resource Availability

In considering the availability of resources, PacifiCorp made several significant assumptions. First, it assumed that all contract expirations are permanent. Second, PacifiCorp assumed that resources would retire as described by the current depreciation study. Third it assumed 1200 MW of short and intermediate term market purchases as existing resources. Finally, it assumed 1400 MW of wind, 100 MW of QF production, and 131 MW of DSM identified by *IRP 2003* but not yet in service.

PacifiCorp assumes the following contracts will expire within the planning horizon: the 400 MW TransAlta contract in FY 2008; the 190 MW West Valley lease in FY 2009; and the 575 MW BPA Peaking contract in FY 2012. The Committee notes that these contract expirations significantly influence the timing and size of the resource need, and that continuing such contracts might be more economic than meeting the need in some other manner.

PacifiCorp has not always assumed resources disappeared from service in the same years identified by the current depreciation study. It coordinated its depreciation study with its IRP in response to a Utah Commission order. However, it appears that the desire for early cost recovery often drives depreciation cases, while in reality plants will be refurbished and operated as long as possible. Removing plants in outer years, which in fact remain in service, can cause distortions in the power cost information. The Committee recommends that extending the life of retiring plant through added investment should be studied and that the necessary investments to extend the life should be modeled as resource options.

Third, the Company included 1200 MW of flat and shaped, short and intermediate term market purchases as existing resources. It added 500 MW of flat products on the west side of the system and 700 MW of shaped seasonal purchases on the east side. While the Committee recognizes the potential benefit of purchases that are shaped to the need, the Committee also notes that this decision was not subjected to risk analysis and believes such a decision should be an output of the IRP, not an unexamined input.

Finally, the Committee notes that PacifiCorp's actual resource availability may be either larger or smaller than forecast, depending on its success in acquiring wind resources and DSM, and on the actual amount of QF activity that materializes.

3.1.1.2 Load Forecast

PacifiCorp's load forecast is developed quarterly. For the purpose of this IRP, a single quarterly forecast was locked down and became the IRP load forecast. The forecast included power sales that PacifiCorp is obligated to provide. PacifiCorp did not provide a range of forecasts as required by the Standards and Guidelines.[5]

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[5] The Committee notes that the stochastic risk analysis does vary load along with other critical variables, but only the effect on cost is assessed. The timing of resource additions remains invariant.

Because of the importance of the Company's load forecast to the overall determination of resource need, and because of concern in the Utah community that the Utah load forecast was high, the Committee spent significant time in investigating the reasonableness of the Company's single forecast. This investigation was complicated by the fact that the historical load information provided in Appendix I, pages 134-136 is reported for fiscal years, but the historical data files in the regulatory community are in calendar years. Also, the historical information in the IRP is reported for each control area and includes sales for resale, while other historical data bases did not include these sales. Some of the results of the Committee's investigation are attached as Exhibit Two, which consists of eight pages of graphics.

While power that the Company is obligated to deliver must be included in an assessment of need, the Company supposedly does not plan its system to provide power for resale. Presumably, it plans the system to provide least-cost, least-risk power to its retail jurisdictional customers, and sales for resale are but a residual. So, the Committee does not understand the purpose of including these sales when reporting historical jurisdictional load data as was done in Appendix I.

Further, when attempting to evaluate average jurisdictional growth rates across the period FY 1991 to FY 2003, the inclusion of these sales can have a distorting effect. As can be seen on page three of Exhibit Two, there were no sales for resale in FY1991. The sales began in FY1992 and grew to a high of 430 MW by FY 1998 before again declining to 0 in FY 2003. Therefore, if sales for resale are included in comparative growth statistics within the period, they will either overstate or understate the actual jurisdictional growth. Because the Committee had alternative data available that did not include sales for resale, it ignored these sales in evaluating the reasonableness of PacifiCorp's load forecast.

The Committee can draw no definitive conclusion regarding the reasonableness of PacifiCorp's load forecast. However it notes a glaring discrepancy between the Utah coincident peak and non-coincident peak forecasts as compared to historical data. While PacifiCorp appears to be significantly overforecasting Utah's non-coincident peak growth, it appears to be underforecasting Utah's coincident peak growth. [6] This

[6] The Committee found that Utah's non-coincident peak forecast appears overly optimistic whether 13 years, 10 years, or 5 years of historical data were considered and whether sales for resale were included or excluded. Utah's non-coincident peak growth has averaged between 141 and 156 MW per year. These actual data are in contrast to PacifiCorp's forecast of 228 MW per year over the next ten years.

PacifiCorp's coincident peak forecast appears reasonable in light of ten years of data. Utah's coincident peak grew an average of 216 MW per year over a ten year period, while PacifiCorp forecasts an average increase of 227 MW per year over the next ten years. However, when the historical data are reviewed, one can see that Utah's growth was not linear over that time period. Coincident peak growth grew steadily at roughly 65 MW per year from 1991 until FY1999. In FY 1999 the system peak shifted from winter to summer. This combined with the reassignment of some industrial load from interruptible to firm in 2000 significantly increased coincident peak load growth. The average increase in Utah's coincident peak approaches 273 MW per year since the shift in system peak. When only the last five years of data are considered (since the shift in system peak), PacifiCorp appears to be underforecasting Utah's peak growth. Finally, the Utah energy forecast appears high when compared to ten years of historical data but slightly low when compared to five. This seems inconsistent with the Company's desire to exclude the recessionary years in this period because of their dampening effect on historical growth rates.

discrepancy must be explained in order to have any reasonable comfort that PacifiCorp's estimate of need is sound. The Committee believes the Commission should direct the Company to explain the relationship between its coincident peak, noncoincident peak and energy forecasts. The Commission should consider withholding acknowledgement until it is satisfied that the load forecasts are reasonable.

Because the Company had not provided a range of forecasts, the Committee attempted to gain an understanding of how the size of the resource need might change if the load forecast were off by half a percent. If loads grow one half a percent slower or faster than forecast, system need would vary up or down by approximately 450 MW over the FY 2006 to FY 2015 time period. The timing of the resource need would change as well.

The Committee anticipates that with the incorporation of the CEM into the Company's box of tools, PacifiCorp will find it easier to comply with the IRP requirement to provide a range of forecasts in future IRPs.

3.1.2 Stage Two: Portfolio Development

In the second stage, IRP staff hand developed portfolios of resources that met the identified need within "development guidelines."

They first built what was termed the Reference Portfolio A and then made modifications to improve upon it. Portfolio A represents what PacifiCorp operations experts believed to be an appropriate way to meet its resource need.

Portfolio A adds a CCCT in Utah in FY 2009, a pulverized coal unit at Hunter in Utah in FY 2011, a CCCT and two IC Aeros on the west side in FY 2013, a CCCT in Utah in FY 2014 and an IGCC unit at Bridger in Wyoming in FY 2015. This portfolio is nearly identical to Portfolio E that became the Preferred Portfolio with the addition of DSM. This is because Reference Portfolio A differs from Supply Side Portfolio E only in the coal technology used in FY 2015. Exhibit Three provides a comparison of Reference Portfolio A and the Preferred Portfolio.

Having developed its reference, the Company then altered aspects of Portfolio A to investigate how costs would change.

- Portfolio B tests the effect of replacing a unit at Hunter with a CCCT.
- Portfolio C tests replacing the FY 2009 CCCT with IC Aeros.
- Portfolio D tests the effect of a timing change. It switches the unit at Hunter with the CCCT slated for FY 2014.
- Portfolio E replaces the FY 2015 IGCC unit with a pulverized coal unit.
- Portfolio F replaces the Hunter unit with a unit at Bridger.
- Portfolio G moves a west side gas plant to the east to see if the lower gas prices on the east compensate for the higher heat rate of the altitude gain.
- Portfolio H replaces a CCCT with compressed air energy storage.
- Portfolio I replaces a CCCT with hydro pumped storage.

- Portfolios J, K, and L, repeat Portfolios B, C, and D but replace the FY 2015 IGCC unit with pulverized coal.
- Portfolios M and N are all gas. M is all gas with CCCTs. N combines CCCTs with IC Aeros.
- Portfolio O replaces the pulverized coal unit at Hunter with an IGCC unit.
- Portfolio P represents a run using the CEM before it was fully operational.
- Portfolio Q replaces the IGCC unit in FY 2014 with a coal unit and moves up the FY 2015 coal unit. It is the only portfolio to have more than two coal units and was added at the Committee's request.
- 18% (Planning Reserve Margin) adds two IC Aeros to Portfolio E.[7]
- 12% (Planning Reserve Margin) removes the FY 2009 CCCT and adds an 87 MW IC Aero in FY 2010, FY 2012 and FY 2013 to Portfolio E.
- Front Office Transactions: In this stress run the front office transactions were removed and an additional three CCCTs were added to portfolio E.
- CHP: Portfolio E modified with Combined Heat and Power on the west side.
- Standby Generation: Portfolio E modified with Standby Generation.

The Committee believes that the general portfolio building approach—beginning with what is believed to be a nearly optimal mix of resources and then improving on it—is sound in concept, but difficult to successfully complete. The main reason for the difficulty is the time required for such an approach. It appears to the Committee that to successfully identify a least cost portfolio would take several iterations of portfolio development, modeling, risk analysis, and refinement. It further appears to the Committee that in trying to meet its regulatory deadlines, PacifiCorp took ill-conceived short cuts and stopped before achieving the goal.

After completing the first round of simulations, in an apparent attempt to shorten the process, PacifiCorp winnowed the number of portfolios for consideration in the risk phase of analysis by using the portfolio cost. In doing so, PacifiCorp was left with portfolios that were substantially similar.

This decision to winnow the field in such a manner was either a strategic way of ensuring particular portfolios were considered, or it was a technical misstep. Either way, it rankled stakeholders, for it is in the risk analysis that the advantages and disadvantages of particular technologies become apparent. Technologies screened out through the winnowing process included IGCC, pumped air energy storage, and hydro storage. That alternative technologies were not subjected to risk analysis is unfortunate. The Committee encourages the Company to seriously evaluate alternative technologies such

[7]The tables in the results section make it appear as if Portfolio A was modified for the stress portfolios. This is because the table indicates an IGCC resource rather than a pulverized coal resource in 2015. However the text indicates the modification was to Portfolio E. We are assuming Portfolio E is correct. If this were not the case, the stress runs would be meaningless.

as IGCC and storage technologies in conjunction with wind resources in the stochastic modeling phase of the next IRP cycle.

By not subjecting all portfolios or at least a wider range of technologies to risk analysis, PacifiCorp's "learning process" appears to have been somewhat disingenuous or naive. What PacifiCorp learned from the deterministic runs, it knew prior to conducting the study. For example, it knew that if it replaced the IGCC plant in Portfolio A with a pulverized coal plant, deterministic cost would decline.

The "development guidelines" that PacifiCorp referred to in describing the portfolio building process may have limited the options explored. It appears that they may have limited the composition of portfolios as well as the planning margin.

Given the portfolios that were ultimately chosen for risk assessment, it appears that PacifiCorp was most interested in exploring what combination of a maximum of two coal units combined with natural gas-fired plants, given 1200 MW of market purchases, would be least-cost, least risk.

Exhibit Four displays the original sixteen portfolios ranked by the percentage of each portfolio that was gas-fired. All but two of the portfolios considered were more than 60% natural gas-fired. PacifiCorp refers to the portfolios in the 66% range as diversified. Portfolio Q, the only portfolio that made it into the risk analysis with less than 60% of the portfolio comprised of gas units was added at the Committee's request. PacifiCorp refers to this portfolio as extreme.

3.1.3 Stage Three: Power Cost Simulations

After developing the portfolios for evaluation, the costs of the portfolios were estimated by combining the proposed resources with the existing system and simulating operation.[8] The costs of operation were then combined with the fixed costs of the resources included in the portfolio. The costs of the portfolio runs are reported as the present value of revenue requirement (PVRR). PacifiCorp used the results of these runs to refine its portfolio development prior to conducting risk analysis.

The results of this process are referred to as deterministic. They are "determined" by the output of the simulated operation of the system, which is itself determined by the underlying assumptions.

However, the likelihood that actual costs will track the cost estimates derived in this deterministic manner is highly unlikely because of the many assumptions embedded in the single deterministic cost estimate. A deviation of the actual value of any one of these

[8] The Committee has some concerns about the IRP production cost results, which arose from a comparison the Committee conducted in a recent QF proceeding that compared GRID results to the IRP results for the same time period, using what was alleged to be the same modeling assumptions, and yet found that the production cost results were significantly different.

Part of the difference the Committee now understands can be explained by the fact that GRID models all fixed costs associated with transactions, while some of the fixed costs have been left out of the IRP model, and GRID models a different load forecast compared to what is included in the IRP. These differences explain part of the $216 million dollar difference between GRID and the IRP model but it's unlikely that this explains all of the difference.

assumptions over the 20-year planning horizon will result in actual costs not tracking estimated costs.

For example, if the actual market price is higher or lower than the forecast, it will affect the value of all portfolios. If market prices are higher, portfolios that require larger amounts of spot market purchases will be more expensive than estimated while portfolios with a surplus of base load plant will be able to sell this surplus and generate revenue, thereby lowering the costs of such a portfolio from its estimate, and vice versa. If actual natural gas prices are higher than the base case forecast in the deterministic runs, the actual cost of natural gas-fired resources will be higher than the estimated cost, or vice versa. If loads are higher than forecast, or outages are higher than expected, in actual practice PacifiCorp will have to rely on the market for a greater proportion of resources to meet need. The relation of the actual prices prevailing at such a time to the previously forecast prices will determine the actual power costs. And so forth.

Because of the uncertainties inherent in planning, understanding the actual variability of key assumptions is critical and risk analysis essential. The third stage of analysis therefore consists of evaluating the risk of alternative portfolios.

3.1.4 Stage 4: Risk Analysis

The Company provided three types of risk analysis: stochastic; scenario; and what it terms paradigm risk. The Committee compliments the Company on its fine stochastic risk analysis and its evaluation of carbon risk. To add to the understanding provided by these three risk analyses, the Committee further proposes that sensitivity analysis of key assumptions be added in the next IRP cycle.

When key variables behave randomly but within the known parameters of past behavior, the parameters can be described by a statistical process, and the risk created by the random variation can be modeled using stochastic risk techniques. For example, because loads vary with temperature, the probability that temperature will vary from its average can be used in modeling the cost associated with the risk that loads will deviate from the forecast. As long as weather patterns continue as they have in the past, stochastic analysis will capture this risk. The five key variables allowed to randomly vary in the stochastic risk analysis are retail loads, natural gas prices, electricity prices, hydroelectric generation, and thermal unit availability.

Because risk analysis is time intensive, PacifiCorp did not analyze all portfolios developed. PacifiCorp first screened the deterministic runs by choosing those with the lowest PVRRs. Ten of the twenty-three portfolios developed were subjected to stochastic and scenario risk analysis.

To conduct stochastic analysis, PacifiCorp’s IRP team simulated each of the ten portfolios 100 times. The variables were allowed to vary randomly within specified limits. The team then used the information provided by the 100 runs to develop different measures of risk.

Scenario analysis is used to evaluate potential fundamental shifts in industry parameters for which there is no past experience. For example, as global warming changes weather patterns, stochastic analysis will be unable to fully define the risk associated with temperature change and load variation. In similar fashion, fundamental changes in the natural gas market may not be captured by stochastic analysis, nor would the imposition of carbon dioxide, mercury or other emissions limits. To analyze this type of risk, the underlying parameter is altered or an assumption is added, all else held constant, and the portfolio's power costs are again simulated. The change in operating characteristics and associated costs is attributable to the parameter whose risk is being evaluated.

PacifiCorp evaluated two scenario risks for this IRP, the risk of a fundamental shift in the natural gas market and the risk of the imposition of even higher carbon dioxide emissions costs than assumed in the base case. The Committee agrees that both pose significant scenario risk. However, while the range of carbon tax adders seems to have been adequately addressed in a methodologically sound manner, the Committee believes that a fundamental shift in the natural gas market was not. This is touched on below.

PacifiCorp defines paradigm risk as "a fundamental structural change to the electricity business model associated with a material shift in market structure or regulatory requirements."[9] Because the details of such a change are completely unknown, modeling such changes with statistical techniques is not possible. Instead the situation is subjected to qualitative analysis—a mental exercise. PacifiCorp identified the formation of Grid West as a paradigm risk which is also addressed below.

3.1.5 Stage Five: Development of the Preferred Portfolio

Once the risk analysis was completed, PacifiCorp used the results and its judgment to identify the optimal supply side portfolio.[10] It then combined the results of its demand side analysis with the results of the supply-side portfolio to determine the optimal or "preferred" portfolio.

Supply Side Portfolio E was chosen as the Preferred Supply Side Portfolio. The Company then added DSM to alter the timing of the resource additions. The CCCT plant initially slated for FY 2009 was delayed one year as was the pulverized coal unit at Hunter. FY 2012 is its new on line date. Finally, the two IC Aeros slated for the west side in FY 2013 were deferred past the ten-year planning period.

3.2 Committee's Analysis of Results.

The Committee believes that the Company has not yet identified a least-cost, least risk, portfolio. The Preferred Portfolio is weighted too heavily with gas-fired resources and may be weighted too heavily with market resources.

The Committee believes that several of the base case assumptions create a systematic bias in favor of gas in a gas versus coal comparison, and it interprets the results from the risk analysis differently than does the Company. Specifically, the Committee believes that Portfolio Q, which differs from Portfolio E by substituting one additional coal unit for a gas unit in the later years, outperformed Portfolio E in the risk analysis, although its deterministic costs are significantly higher.

[9] *IRP 2004*, p 63.

[10] Note that it did not use the information gained through the risk analysis to develop additional runs prior to choosing an optimal portfolio.

If the base case assumptions were adjusted to better reflect current conditions and artificial modeling constraints were removed, the Committee believes that Portfolio Q would rank much better in the deterministic runs and therefore do better in a cost-risk tradeoff. While the Committee does not think Portfolio Q is necessarily the least-cost, least-risk portfolio, it does think the lessons learned from Portfolio Q should be used to refine portfolios for a further round of analysis prior to selecting the optimal portfolio.

Finally, the Committee is concerned that the level of market transactions linked to the potentially volatile short term market was not subjected to explicit stochastic analysis. This is a short-coming that contributed to the Commission not acknowledging IRPs in the past.

3.2.1 Modeling Assumptions

Five key assumptions appear to bias the results of the deterministic analysis toward gas-fired resources: (1) natural gas prices; (2) market prices; (3) capital costs; (4) non-firm transmission modeling; and (5) emission credits.

These assumptions determine the ranking of portfolios by PVRR and strongly influence the risk-cost tradeoff. Altering them would change the operational characteristics and results of the portfolios modeled. The Committee believes that the ranking of Portfolio Q in the deterministic analysis would improve.

3.2.1.1 Natural Gas Prices

PacifiCorp develops its own short-term gas price forecast and blends it with several independent advisory services, primarily the PIRA Energy Group's, in developing its IRP gas price forecast. The long-term forecast is dated May 2004 and the short-term June 2004. Since the lock down of the natural gas price forecast nearly a year ago, the industry has come to recognize that the natural gas market is undergoing a structural change and recent price forecasts are significantly higher. As a result, the gas price forecast used in the base case is quite low.

Exhibit Five displays gas price forecasts from several sources in both nominal and real 2005 dollars. It compares PacifiCorp's base case gas price forecast, its high scenario forecast, the Schedule 38 Stipulation forecast, two forecasts from the Northwest Planning and Conservation Council's (NPCC) Fifth Regional Power Plan, a medium and a high, and the new Energy Information Administration (EIA) base case forecast. All comparative forecasts exceed PacifiCorp's base case forecast.

PacifiCorp refers to its high case as an extreme. The Committee questions this assessment. While PacifiCorp's high exceeds other forecasts from 2010 to 2015, it is less than the NPCC's 2004 high forecast between 2006 and 2010, and it approaches the EIA current base case in the outer years.

The Committee also notes that all gas price forecasts are flat when viewed in real terms and questions how flat real prices will likely be. While energy prices had been declining in real terms in the past, the idea that natural gas prices will grow at the same rate as inflation does not seem consistent with the concept of an increasing cost natural gas industry.

Low natural gas prices favor gas-fired resources. As natural gas prices rise, the lower operating cost of coal outweighs the disadvantage of its higher capital costs and lower emissions credit assumption.

3.2.1.2 Market Prices

While PacifiCorp's forward price curve is considered confidential, given the close tie between gas price and electricity prices in PacifiCorp's modeling of electricity prices, this assumption, too, will be low. When market prices are low, coal-fired resources are less advantageous. The disadvantage of higher capital costs tends to outweigh the benefit of lower operating costs. Higher market prices favor coal units because a utility can secure higher margins on the sale of surplus power during off-peak periods. Thus, higher market prices will lower the costs of portfolios with more coal.

3.2.1.3 Capital Costs

PacifiCorp's assumed capital costs also appear to bias the results toward natural gas-fired resources. While PacifiCorp's capital costs are systematically higher than other sources of information, this pattern is most pronounced in the pulverized coal capital cost assumptions and to a lesser extent in the IGCC capital costs. However, the IGCC costs may be affected by PacifiCorp's higher elevation.

Exhibit Six provides a comparison of capital costs from *IRP 2004*, the NPCC's Fifth Regional Plan, and the EIA January 2005 Annual Energy Outlook.

3.2.1.4 Non-firm Transmission Modeling

A utility can meet its peak needs in two ways. One, it can shape its resources and purchases to follow peak demand with little excess in the shoulder hours, or, two, it can meet the peak with baseload plants (with lower operating but higher capital costs) and then sell off the shoulder excess. However, in order to sell the excess, market prices must be attractive, and transmission capacity must be available. PacifiCorp's assumption that nonfirm transmission capacity is not available limits the model's ability to dispose of shoulder hour surplus and therefore does not adequately capture the benefit of coal. Since gas plants have higher operating costs than coal plants, their market opportunities will be more limited than those of a coal plant and they will be less affected by this artificial modeling constraint.

PacifiCorp recognizes the influence of this assumption on power costs in footnote 14 on page 115. The footnote states: "Note that in accordance with the firm transmission rights market constraint outlined in the System Topology section of Chapter 3, capacity utilization trends shown in this chart and others in this document reflect a conservative market size assumption that doesn't account for non-firm transmission or opportunities to make additional market sales and purchases."

3.2.1.5 Emissions Modeling

The assumption of the development of perfect cap and trade markets in emissions credits significantly affects the ranking of portfolio costs.

PacifiCorp has taken a socially responsible and risk averse stance with regards to green house gas and other pollutants, which is admirable, but may be imposing too high of a price risk on customers in the current environment. PacifiCorp assumes that national legislation will be passed that limits a utility's emissions to some time period. The time period assumed by the IRP is 2000. It is then assumed that markets in emissions credits will develop.

Under such a regime, should PacifiCorp reduce its emissions below its 2000 levels through retirement of dirtier units and the addition of cleaner units, it could sell credits to utilities that are running dirtier plants.

If PacifiCorp's emissions were to exceed its 2000 level, it would have to buy credits from selling utilities. Since, gas-fired plants have lower emissions than coal-fired plants, operating a system that has a larger proportion of gas-fired resources would generate more credits than a system with more coal. Adding coal units would lower the total emissions credit but could still generate credits if old dirtier plants ran less as a result of a newer, cleaner, more efficient coal plant operating.

Two emissions credit markets exist today, one in Sulfur Dioxide (SO2) and one in Nitrogen Oxide (NOx). However the NOx market currently applies only to the eastern United States. Action on mercury (Hg) is imminent; however whether a cap and trade market will develop or whether emissions limitations will be imposed is yet to be seen.

PacifiCorp assumes the development of cap and trade markets by 2010 for SO2, NOx, mercury, and Carbon Dioxide (CO2). The CO2 market is phased in over two years; by 2012 the assumption of $8/ton is in full effect.

The affect of just the carbon tax assumption can be seen in Table 8.28 on page 158. Table 1.58 ranks five portfolios by cost as the carbon tax assumption increases from $0/ton to $40/ton. The portfolios differ in their percentage of coal. In the $0/ton case Portfolio Q is $1.4 billion cheaper than Portfolio E. With the assumption of $8/ton carbon tax, Portfolio Q costs $300 million more than Portfolio E.

This effect can also be seen in the table below. It appears that the cost to hedge between $300 million to $703 million in emissions risk costs $1.4 billion if federal legislation is not enacted any time soon.

	Carbon Dioxide Cost Per Ton ($Millions)				
Portfolio	$0/ton	$8/ton	$10/ton	$25/ton	$40/ton
E	13,165	13,285	13,339	13,657	13,244
Q	11,816	13,585	13,725	14,187	13,947
Difference	1,349	(300)	(386)	(530)	(703)

Since these assumptions are key determinants of the ranking of portfolio costs, and an important factor in evaluating the risk-cost tradeoff in choosing the optimal portfolio, the Committee would like to better understand how these cap and trade markets might function in reality. In all portfolios modeled, but one, Portfolio Q, PacifiCorp's modeled total emissions were less than its emissions in 2000, so PacifiCorp assumed it was able to sell emission credits that were used to offset portfolio cost. The Committee would like to better understand whether there would in fact be buyers for these credits. Assuming emission limits are imposed, how liquid will these emissions markets be, particularly in the West? Will PacifiCorp find a buyer for all emissions credits, and at what price?

Finally, the Committee believes that emissions risk must be seriously evaluated, and it appreciates PacifiCorp's proactive approach. However, the Committee is uncomfortable including this assumption in the base case because of the uncertain timing of the legislation and the resulting cost impacts. Once legislation is passed, the Committee agrees that it would be appropriate to include emissions credit assumptions in the base case. Finally, the Committee notes that the inclusion of this assumption in the base case appears contrary to the Commission's stated direction in its last order.

3.2.2 Modeling Results and Observations

Further evidence in favor of coal can be found by reviewing the results of the Portfolio B simulation.

Portfolio B replaces the 575 MW pulverized coal plant at Hunter slated for FY 2011with a 525 MW CCCT. The results show that Portfolio B (the Portfolio with the added gas plant) costs slightly more than Portfolio A (the Portfolio with the pulverized coal plant). PacifiCorp explains that the higher fuel cost of the CCCT outweighs the higher capital cost of the coal unit. PacifiCorp tells the reader than in FY 2015, the Utah coal resource had a variable cost of $12.18/MWh compared to $40.07/for the CCCT.[11] Note that this result occurs despite the bias in the modeling assumptions listed above.

3.2.3 Results of Stochastic Risk Analysis

The real benefit of coal resources is the price stability they provide. This information is found in the results of the stochastic risk analysis.

To conduct stochastic analysis, PacifiCorp's IRP team simulated each of the ten portfolios it evaluated 100 times. The variables were allowed to vary randomly within specified limits. The team then used the information provided by the 100 runs to develop alternative measures of risk.

3.2.3.1 Average Risk

The mean and the variance of the 100 power cost simulations provide a measure of average risk. The mean is the expected value or expected cost of actual portfolio performance in a world where actual values vary from their assumed levels. The Committee believes ranking of portfolios by their expected value is more meaningful than ranking portfolios by their deterministic costs.

In the deterministic rankings, only one portfolio, a portfolio that targeted an 18% planning reserve margin was more expensive than Portfolio Q. However, in the ranking of expected value, Q was dead center.

Portfolio Q's costs were the most stable of all portfolios. Portfolio Q had the least amount of variance in cost across the 100 runs when compared to the other Portfolios.

In a composite measure of average risk, as displayed in Figure 8.16 on page 144, Portfolio Q tied with Portfolio E for first place. Figure 8.17 is a scatter plot that displays

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[11] *IRP 2004*, p. 114.

expected cost on one axis and variance on the other. In interpreting a scatter plot, one can say that all points to the northeast of any other point are inferior. So, Portfolios P, J, 18%, M and N are inferior to Q. Portfolios K, L, 12%, P, J, 18%, M and N are inferior to E. But E and Q are indifferent to one another. E and Q represent different trade-offs. Whether the attribute of expected value is weighted higher or whether not being surprised by price variation is weighted higher is a policy decision that can not be answered by a quantitative analysis.

3.2.3.2 Risk Exposure

While the mean and variance of the 100 runs provide important information, customers are often concerned with risk exposure. The mean and variance of the five most costly runs for each portfolio provide two measures of risk exposure.

Portfolio Q had the lowest risk exposure of any of the portfolios subjected to stochastic risk analysis as measured by the mean of the five most expensive runs. Differences in the variances were not statistically significant and so were not reported.

In a composite measure of average risk and upper tail risk, Q won hands down. This is shown in Figure 8.2 on page 148.

3.2.3.3 Risk-Cost Trade Off

The risk-cost trade off can be thought of in various ways. The Company compared the deterministic cost for each portfolio to its risk exposure. Figure 8.2.1 provides a graphical representation of the information. The Company then concluded that E and K have the best risk-cost tradeoff. While at first glance, one might agree with this conclusion, it is not strictly correct. Portfolios Q, E, K, and P all represent a different policy tradeoff. Only portfolios that lie strictly southwest of another are its superior.

However, the Committee believes that the expected value is a better cost metric than the deterministic cost displayed in Table 8.21. We have reproduced Table 8.21 replacing deterministic cost with the expected value and displayed the information in Exhibit Seven. As can be seen, Portfolio Q is again tied with Portfolio E for first place. Portfolio Q represents more stable prices but with a higher expected cost than Portfolio E. Portfolio E represents a lower expected cost but with greater price variability than Portfolio Q. As before, which attribute should be weighted most heavily is a policy decision. If price stability and protection from upper end risk exposure are most important, then Q is preferred to E. If customers are willing to trade some risk exposure for a lower expected value, then E is preferred to Q.

3.2.4 Other Observations with respect to Portfolio Q

- Reduces output from other, presumably dirtier, coal plants.
- Reduces output from gas units, reducing gas price risk.
- Reduces purchases and sales, thereby reducing reliance on the market.
- Only portfolio to exceed PacifiCorp's 2000 emissions levels increasing emissions risk.

3.2.5 Scenario Risk

The Committee wishes to again compliment the Company for its thorough and consistent analysis of the risk of CO2 taxes that exceed its base case assumption of $8/ton. The Committee appreciates the integration of the electricity, natural gas, and other emission markets into the analysis of emissions risk. The Committee requests that the Company take equal care in addressing gas-price risk in the next IRP round. The Committee notes that while the Company stated that higher gas prices would lead to higher electricity prices, it does not appear that higher electricity prices were in fact modeled. The Committee also disagrees with the Company's statement that its gas-price risk represents an extreme case, as noted earlier.

3.3 Alternative Portfolio Request

As stated above, the Committee believes that the Company did not identify the least-cost, least-risk plan. While there will be opportunity in the next IRP cycle to address the viability of later gas-fired additions and potential alternatives, such as a combination of Integrated Gasification Combined Cycle technology (IGCC) and wind resources, the Committee is particularly concerned with the addition of the third Combined Cycle Combustion Turbine (CCCT) on the east side of the system in FY 2010, which requires commitments within the current Action Plan timeframe.

The Committee has carefully analyzed the information provided by the Company and has discovered at least two supply-side options in the near term that to our knowledge were not explicitly evaluated during the IRP process that meet the resource obligation in FY 2010 but do not commit the Company or its ratepayers to the cost of a CCCT.

The Committee used the Preferred Portfolio as the reference. For both alternatives, the Committee requested that the CCCT in FY 2010 be removed and Hunter moved forward to FY 2011 as it was modeled in Reference Portfolio A and Portfolio E. To meet the FY 2010 need the Committee requested the following additions: (1) add 3 IC Aero units (261 MW); (2) continue the 190 MW West Valley Lease and add 75 MW of Standby Generation. The Committee did not request changes in the outer years because they are beyond the immediate planning period. However, Committee Staff will be discussing possible alternatives with the Company such as bringing forward a Bridger unit, either pulverized coal or IGCC, by two years and adding a wind resource in 2015. Unfortunately, by not specifying a specific low-risk resource in the outer years, the risk of market resources may be substituted for the risk of natural gas. This may need to be immediately addressed to provide a reasonable comparison.

3.4 Market Resources

The Committee is quite concerned with the level of market purchases that may be tied to the short-term spot market without adequate risk analysis and recommends that the Commission direct the Company to address this shortcoming immediately. The Committee urges the Commission to indicate to the Company that its shareholders are at risk for extreme prices when the Company does not undertake adequate risk analysis.

The Committee believes that the Commission should direct the Company to disclose the volume of transactions subject to indexing and that this volume, including the 1200 MW of front office transactions, should be subjected to stochastic risk analysis. In FY 2009, the front office transactions alone are forecast to meet 10% of total energy requirements.

On page 33 of the IRP, the Company reports meeting 21.9% of energy requirements through short and long term purchases and further states that "[m]any of PacifiCorp's purchased electricity contracts have fixed price components, and these provide some protection against price volatility. But the report does not indicate the percent of purchases hedged or indexed. To the extent that purchases, even long-term, are tied to market indices, they provide little or no protection from the risks inherent in a hybrid market.

The Committee is additionally concerned by the risk of 700 MW of shaped seasonal purchases on the east side. If these purchases are indexed or require renewal in the midst of a dysfunctional market, Utah customers could bear a disproportionate share of the costs of these resources as a result of the seasonal resources component of the Revised Protocol.

Based on recent experience, we all know that the consequences of counting on relatively stable markets to serve load or price firm resources can be severe. Therefore, the Committee does not understand why the Company appears unwilling to undertake stochastic risk analysis of these its indexed and relatively short-term purchase contracts. And, the Committee disagrees with the Company's conclusion that "there is a very low probability of a return to 2000-2001 crisis conditions."[12]

The WECC Power Supply Assessment completed last fall shows the possibility of tight circumstances arising this summer. Under certain modeled conditions, the assessment shows deficits developing in the Southern California-Mexico region of the interconnection as early as 2005—the interconnection becomes deficit by 2008. While the Northwest and Canada remain surplus throughout most of the analyzed period, the WECC Power Supply Assessment is based on capacity, not energy, which could overstate these regions' power availability.

And, indeed, concerns have arisen over the possibility of problems in Southern California this summer. Apparently, Southern California Edison has adequate financial rights to cover its load requirement, but not physical rights. And the northwest has experienced one of the driest winters in history, so they may not have the power to help. These conditions could send market prices soaring.

Another factor that could lead to market dysfunction is the formation and operation of Grid West. The formal energy and ancillary services markets that would be formed could provide opportunity for gaming as could market design discrepancies between the seams of Grid West and the Cal ISO.

In conclusion, to subject 10 to 20 percent of the Company's energy requirement to market forces without stochastic risk analysis appears imprudent, particularly with the knowledge that was gained in the 2000 to 2001 time period. Or perhaps the Company has evaluated the risk, doesn't want to meet its load obligation through firm resources for

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[12] Draft Report page 12.

financial reasons, and is therefore strongly pursuing power cost adjustment mechanisms in its six jurisdictions.

3.5 Transmission Issues

In its last IRP Order, 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 especially with respect to the RTO West paradigm." While the Committee appreciates the improvement PacifiCorp made by including transmission to integrate distant resources, the Committee does not believe the Company has adequately or fully responded to the Commission's directive.

In adding the Bridger unit, the Company sized the line to accommodate only Bridger power and included no wheeling revenues. The Committee is not convinced that this is optimal for customers and seems to take a short-term view. The Company should evaluate a larger line that could accommodate additional resources as needed. In the meantime, capacity on the line could be sold and wheeling revenues used to offset ratebased costs. By not including wheeling revenues, the Company has not evaluated transmission on a consistent and comparable basis with generation. Costs are assessed, but benefits are not fully attributed.

As far as the Committee is aware the Company did not include analysis of transmission upgrades in the IRP process although it did in the RMATS process. The Committee would like to see greater coordination between work that the Company is doing on transmission in other venues and the IRP.

3.5.1 Grid West

The Commission specifically directed the Company to improve analysis of transmission "especially with respect to the RTO West Paradigm." The Committee does not believe the Company met its burden. It provided no real analysis, only assertions of benefits with which the Committee does not agree.

The Company seems to believe that the existence of an RTO will make it easier to build the transmission needed to link resources in Wyoming to the PacifiCorp system, presumably by providing a socialization of the costs across the RTO footprint or by identifying beneficiaries. It appears to believe it will get greater cost recovery certainty in an RTO world.

The Committee, on the other hand, believes that an RTO will slow, not speed, the addition of transmission and will not resolve interjurisdictional allocation issues. Instead, it may introduce endless conflict among the affected parties. The Company should understand just how difficult interjurisdictional allocation issues are as a result of its experience with the PacifiCorp Interjurisdictional Taskforce on Interjurisdictional Allocation and the Multi State Process, and it should look to New England to see that an RTO does not resolve allocation concerns.

The Committee believes the best way to achieve recovery of the costs of transmission additions is to demonstrate the benefit to customers through an IRP process. It is not necessary to limit the size of the additions to the immediate needs of native load customers as PacifiCorp has. If wheeling revenues were included in the modeling—

which the Company has been unwilling to do—the Company should be able to demonstrate the benefit of building larger than the immediate need to accommodate off-system sales while customers grow into the resource. Indeed, this was the approach PacifiCorp took in the past.

3.6 DSM

PacifiCorp has shown both the ability and the commitment to successfully implement cost-effective Demand Side Management programs in Utah. The Company's evaluation of DSM in *IRP 2004* determines that it is a cost-effective measure that provides benefits for ratepayers, including reduced exposure to volatile fuel prices and environmental risks, and can delay the need for acquiring supply-side resources.

The CEM was used to select the most cost-effective Class 1 DSM resources from among eight possible proxy programs for the FY 2009 – 2015 period. Each of the proxies had specific end-use operations in mind. Four DSM proxy programs were selected based on the CEM solution and then used to modify Portfolio E, thereby reducing portfolio cost by $139 million. Portfolio E, with the four dispatchable DSM programs, was selected as the Company's Preferred Portfolio.

The Utah Cool Keeper Program Extension was offered as a DSM Program option in the CEM[13]. However, it did not appear as a CEM selected DSM Resource in Table 8.27, page 166, which the Committee found troubling since the Program had been demonstrated to be cost effective. In response to Committee questions, the Company explained that Cool Keeper was not selected in FY 2013 because the existing program contract expires in FY 2014 and therefore it is not eligible to be selected until FY 2015. The Cool Keeper and the Idaho Irrigation Extensions were selected by the CEM and should have appeared in Table 8.27, although the Program Extensions could not be used earlier than FY 2015.

Although both Class 1 and Class 2 DSM provide system benefits, they are modeled differently. Class 1 DSM is dispatchable and can be used to control loads. In *IRP 2003*, Class 1 DSM was manually included in the base case. In this IRP, Class 1 DSM was treated similarly to a supply-side resource, as a potential resource addition. This approach better reflects the value of its dispatchability, which is beneficial in mitigating Utah's peak load growth. The Preferred Portfolio included an increase in economic Class 1 DSM, adding 88 MW in calendar year 2008 and 89 MW in calendar year 2013.

Class 2 DSM was modeled as a decrement to load. Class 2 DSM is not dispatchable but reduces overall energy use, including peak use. The load forecast in this IRP was reduced to reflect the expected energy savings from existing Class 2 DSM programs, including those programs that are expanded to other states, and cost effective programs selected from the DSM RFP-2003. To determine the value additional Class 2 DSM could provide to PacifiCorp's system, eight programs were evaluated, each of which reduced peak load by 100 MW beginning in FY 2009. These decrements follow four load shapes each for the east and the west sides of the system. The decrement analysis provided an estimate of system production cost benefits from DSM-related load reductions. Class 2 DSM programs offered in a future RFP will be evaluated based on values determined

[13] *IRP 2004*, page 166, table 8.26

from this analysis. DSM decrements begin in FY 2009 and continue throughout the 20 years of the planning period.

The *IRP 2004* load forecasts indicate robust growth with the expansion plan calling for the installation of substantial thermal generating capacity (2,629 MW)[14]. This growth provides significant opportunity for expanded DSM programs.

The Action Plan calls for the addition of 100 MW of Class 1 DSM by FY 2009.[15] Action Item 2 calls for the acquisition of 450 MWa of Class 2 DSM, consisting of the 250 MWa base and up to 200 MWa additional from FY 2006 to FY 2015.

While the Committee understands that these programs take time to develop and implement, it encourages the Company to move forward with cost-effective programs quickly and to not be limited by the Action Plan if additional cost-effective programs are available.

3.7 Wind

IRP 2003 identified the need for 1,400 MW of renewable resources. In February 2004 the Company issued an RFP and received offers for over 6,000 MW. As part of this IRP, the Company determined that between 1,200 and 1,600 MW out of the 6,000 MW of offers might potentially be cost effective. The Committee anticipated that cost-effective renewable projects would be well underway. However, no contracts have been executed, although the Company continues to negotiate with short-listed bidders.

IRP 2004 continued to target 1,400 MW of renewable resources. However, it is not clear how renewable resources influence the timing or size of any other resource, given the manner in which the Company incorporated wind resources in this IRP. For example, there is no explanation of what the expansion plan in Table J.5 on page 147 would have been without the renewables. *IRP 2004* simply incorporated 1,400 MW of wind in the resource plan, and then optimized the thermal resource plan with the wind assumption fixed.

Although a completely integrated analysis of all resources including wind was not performed, the Company did perform a post optimization analysis which determined that 1,250 MW of wind resources was reasonable for the PacifiCorp system.

The Committee recommends that in the next IRP cycle, PacifiCorp should undertake a more rigorous analysis of the optimal type and timing of all resources including wind resources. The CEM could easily be used to perform this analysis.

The Company's acknowledgment that wind resources do have a capacity value, and thus provide a contribution towards satisfying PacifiCorp's planning reserve margin, is a significant improvement that the Committee would like to note. The magnitude of the contribution depends on the availability of wind to meet PacifiCorp's summer peak. A number of factors influence wind generation's capacity contribution, including wind speed and duration, which varies by site, as well as, transmission constraints and availability.

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[14] *IRP 2004*, page 167, Table 8.28

[15] *IRP 2004*, page 181, Table 9.2

PacifiCorp reviewed several studies regarding wind generation on system reliability, or its effective capacity contribution for this IRP. One such study was conducted by Xcel Energy, in a joint effort with other organizations[16]. The analysis determined that the wind plant would provide approximately a 30% contribution to planning reserve margin calculation. Other studies that PacifiCorp reviewed determined a capacity contribution that ranged from 10% to 20%.

The methodology outlined by NREL and Xcel Energy was used by PacifiCorp to determine a capacity contribution from wind resources on its system. The study compared the amount of energy not served (ENS) in a base case with no wind to a case in which wind resources were added, but then additional load was also added until the ENS in that case equaled the ENS in the base case with no wind. To achieve the same ENS a much smaller amount of load had to be added compared to the amount of wind resources that were added. The ratio of the amount of load added to the amount of wind capacity was determined to be the capacity contribution of wind resources.

Based on the best information currently available, and the analyses conducted by the Company, the Committee is satisfied with PacifiCorp's 20% capacity credit assumption. However, PacifiCorp's explanation mentions that the results of the study do not reflect wind patterns with strong diurnal patterns. PacifiCorp's comments go on to state that strong diurnal patterns are often the case, yet PacifiCorp makes no attempt to explain further whether it believes that ignoring diurnal patterns has the effect of overstating or understating the capacity contribution of wind plants. The Committee believes that PacifiCorp should evaluate this further and determine the effect that this would have on the capacity contribution of wind resources.

The inclusion of cost effective renewable resources in the Company's portfolio mix provides benefits to the system, including avoiding volatile fuel prices and environmental risks. The Committee encourages the Company to perform additional studies of all renewable resources including biomass, geothermal, hydro and wind in the next IRP.

3.8 IGCC versus Pulverized Coal

During the *IRP 2004* Public Process, PacifiCorp posed the immediate action plan issue as one of gas versus coal. The Committee believes that because of shifts in the industry over the past year, gas versus coal is no longer the central issue. The questions going forward appear to be whether to add pulverized coal resources or to embrace IGCC technology.

The Committee encourages the Company to evaluate and aggressively pursue early IGCC technology and to consider increasing the scale of plant to reduce cost and reduce the volume of market resources. We attach an article from Power Engineering Magazine titled Coal Gasification Striking While the Iron is hot authored by Brian K. Schimmoller, Managing Editor, as Exhibit 9.

Finally, the Committee notes that the addition of IGCC technology might help resolve concerns for both customers and the Company by providing customers with a stably

[16] Technical Appendix for *IRP 2004*, Tab J, page 141.

priced resource and a healthier environment and the Company with less interjurisdictional allocation uncertainty.

4 CONCLUSION

Until recently the standard industry response to meeting growing load obligations was to acquire or build some combination of market and/or gas-fired resources, depending on the size, location, and duration of the need. Economics and environmental concerns drove that response; the western market was surplus, natural gas was relatively cheap, and natural-gas fired resources had fewer environmental impacts than some other relatively low-cost resources such as coal.

This has changed. The western surplus has disappeared, and the expanding use of natural gas to generate electricity coupled with the increasing cost of expanding domestic natural gas supplies appear to have fundamentally shifted the natural gas market thereby resulting in more expensive and more volatile wholesale electricity and natural gas markets. As a result of the increased cost and price volatility of these resources, coal-fired and wind resources located far from load centers with their associated transmission costs are economically viable options providing price stability despite the associated risks of environmental cost adders on coal. In addition, significant strides in standardizing coal gasification technology are helping to address some of the environmental concerns associated with coal resources.

The Committee believes the Company is at a critical juncture. It faces sizeable resource acquisition requirements as contracts expire, plants are scheduled for retirement, and loads continue to grow. At the same time market fundamentals and technological options are in flux. The Company must determine whether it wishes to continue its incremental, shorter-term approach to resource acquisition, thereby exposing its customers and shareholders to the risk of increasingly volatile wholesale electricity and natural gas markets, or whether it will aggressively pursue the future by adopting budding technologies and strengthening its link to the plentiful resources located in its Wyoming service territory and adjacent areas.

The fundamental question facing the Company and its customers in this IRP cycle and the next is whether to continue to link PacifiCorp's resource future to market and natural gas-fired resources in an incremental manner or to develop a long-run vision that develops coal gasification and wind resources. The analysis provided by PacifiCorp's *IRP 2004* indicates to the Committee that developing stably-priced resources is best for customers and shareholders alike.

Finally, the Committee is concerned with slippage in the timeline anticipated by *IRP 2003* for adding a coal resource at the Hunter site. If Hunter 4 were available in FY 2010 as previously determined, the need for a resource in that year would not be problematic for this action plan. It appears to the Committee that the slippage may be related to the Company's concern of less than full cost recovery of a coal resource which is delaying internal decision making. To discourage such slippage in the timelines associated with the lower-risk resources identified by this IRP and the RMATS process, the Committee recommends that the Commission direct the Company to take immediate action to develop and integrate stably-priced Wyoming resources as soon as possible.