State of Utah
DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: The Public Service Commission of Utah

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Date: October 13, 2006

Subject: Docket No 05-035-47: In the Matter of the Application of PacifiCorp for Approval of a 2009 (2012) Request for Proposals for Flexible Resources.

1 INTRODUCTION AND SUMMARY

The Committee of Consumer Services (Committee) appreciates the opportunity to again provide input on PacifiCorp's proposed Request for Proposals (RFP). In the last round of comments, the Committee responded to perhaps the most significant issue raised by this RFP—whether the benchmarked resources identified by the RFP are technically justified by PacifiCorp's Integrated Resource Planning (IRP) activity. We concluded that they are and directed readers to our comments in several past IRP proceedings for the details of our rationale.

In this set of comments we reiterate our position that the RFP benchmarks are consistent with IRP planning activity, highlighting PacifiCorp's significant resource need, deteriorating western market conditions, and the risks associated with front office transactions. We next address the issue of bridging resources and conclude that supercritical coal plants may be a necessary component of a bridge to span the large resource need until preferable technologies become commercially viable. Finally we disagree with the recommendation to index costs in Power Purchase Agreements (PPA) in order to create a more level playing field for developers. We conclude that shifting the risk of cost increases from developers to ratepayers deviates from the principle that risk should follow reward and is at odds with the intent behind competitive bidding—ratepayer benefit.

For the above reasons, the Committee concludes by recommending that the Commission approve the RFP without modification to its benchmarked resources or contract structure as specified in the October 4, 2006 version of the RFP.

2 DISCUSSION

2.1 RFP Bench Mark Resources

As we stated in our last set of comments, the Committee supports the RFP benchmark resources.[1] We perceive a significant need and the consequences of not filling the supply-demand imbalance with firm stably-priced resources as quickly as possible as potentially severe. For these reasons the Committee supports the RFP benchmark resource size, and, as we discuss in our comments regarding bridging resources, the benchmark resource type. Furthermore, while the RFP portfolio differs from the optimal portfolio identified by the IRP 2004 Update (Update), we believe the RFP benchmarks are consistent with the results of the integrated resource planning process once front office transactions are properly evaluated, and market risk accurately measured.[2]

2.1.1 Front Office Transactions and Resource Need

As part of our review of the Update, the Committee spent considerable effort evaluating PacifiCorp's load and resource balance and the market risk of its acquisition plan. The Committee became quite concerned that the reported load and resource balance did not adequately reflect the real need and that the stochastic analysis was not measuring the actual risk. Central to our concern was the treatment of front office transactions.

In IRP 2004 and the Update, PacifiCorp included 1200 MW of front office transactions as existing resources in determining its load and resource balance. It included 700 MW of summer-peaking purchases on the east side of the system and 500 MW of a flat energy product on the west side. So the load and resource balance understated the system need by 1200 MW and the eastern need by 700 MW.

The effect on PacifiCorp's load and resource balance and planning reserve margins with the front office transactions removed is shown in Exhibits E and F of the Committee's IRP Update comments. Exhibit E depicts the system position prior to the addition of planned resources. Exhibit F depicts the system position with the resources identified by the Update included in the balance.

As displayed in Exhibit E, the planning reserve margin is less than 12% beginning in 2008 and becomes negative in 2012. By 2014, the planning reserve margin is seriously negative.

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[1] Because our discussion in this section relies heavily on the comments we provided to the Commission on PacifiCorp's IRP 2004 Update (IRP Update Comments), we are attaching these comments and their associated exhibits for the benefit of the reader. Committee of Consumer Services, *Comments of the Committee of Consumer Services regarding PacifiCorp's Integrated Resource Plan 2004 Update*, Docket No. 05-2035-01, May 5, 2006.

[2] Ibid. See Section 3.4.5, pp 18-20.

Even after the resources identified by the Update are included in the load and resource balance, without the inclusion of the front office transactions, the system remains significantly short, and the east control area particularly exposed. This can be seen in Exhibit F. The east control area's planning reserve margin declines from under 9% in 2012 to 2% in 2014. The Committee believes such thin margins are unacceptably risky.

Significantly, this risk was never evaluated in the IRP process. The stochastic modeling did not assess the risk of the front office transactions on which the system relies to meet a significant portion of its capacity needs. The price of the seasonal peaking product reflected the Company's forward price curve and was not allowed to vary in the stochastic risk modeling. The flat west-side energy product was also priced at the forward price curve. Although its price was allowed to vary in the stochastic analysis, it was capped at $70/MWhr. As discussed in our Update comments, the full risk of spot market purchases was not evaluated either.[3]

Our conclusion from the above discussion and the full analysis included in our IRP 2004 Update comments is that the IRP Update portfolio did not add adequate reserves and left PacifiCorp's shareholders and customers exposed to market risk that was not evaluated in the planning process.

The Committee applauds PacifiCorp for increasing the size of its solicitation and taking steps to protect its shareholders and customers from market consequences should the market again become dysfunctional.

2.1.2 Market Risk

The Committee believes that the possibility of market dysfunction is on the rise as the result of tightening supply conditions, increased competition for existing resources in the Southwest, and California's implementation of a market redesign.

- The May 9, 2006 WECC Power Supply Assessment reveals broad near-term deficits if resources are not added soon. The southern part of the western interconnection requires additional power as early as the summer of 2008-2009. While the northwest has adequate surplus, transmission is not available to move this power south.[4]
- A new transmission line from the Palo Verde region into southern California could affect the liquidity of the Palo Verde market, diminishing PacifiCorp's ability to compete for economically priced power. Southern California Edison (SCE) is constructing a line that will increase the import capability from the Palo Verde market hub into Southern California by 1200 MW. SCE expects to complete construction in 2009.
- Finally, the implementation of the California Independent System Operator's (ISO)

[3] Ibid.

[4] With the use of a 15% planning reserve margin, deficits appear in the Rocky Mountain Region, the Desert Southwest, and Southern California in the summer of 2008. With the use of a significantly more relaxed planning standard but a hot summer scenario, the deficits in the Desert Southwest and Southern California are delayed by a year but are significantly larger. The Rocky Mountain region's deficit still appears in 2008. See in particular, pages 5-7. The graph on page 7 is particularly illustrative.

Market Redesign and Technology Upgrade (MRTU) could have unintended consequences for the rest of the West. The ISO will begin implementing its new day-ahead energy market and LMP pricing in November of 2007. Price caps will increase from $400/MWhr to $1,000/MWhr over a period of two years.

2.2 Bridging Resources

Both the Western Resources Advocates (WRA) and the Utah Association of Energy Users (UAE) promote consideration of alternatives to the large scale resource acquisition solicited by this RFP. The concept they propose is to bridge the resource need with alternatives such as aggressive demand side management (DSM), aggressive renewables acquisition, and shorter-term market purchases until better information demonstrating IGCC's commercial viability and/or other technological advances or resources become available. These alternatives have been termed "bridging resources." Bridging resources are considered desirable because of the large uncertainties resulting from climate change and the desire to avoid adding additional pulverized coal units with their associated emissions and long lives.

The Committee is sympathetic with these concerns and supports aggressive demand side management and renewables procurement. However, our assessment of the size of the need, the risk of the market, and the length of the bridge required to span the time period until the technological uncertainties become known appears to differ from UAE's and WRA's assessment.

As discussed above, we recognize a large, immediate resource need and perceive an increasingly risky short-term market. However, it appears that we may view the length of time that bridging resources would be required to be significantly longer than others seem to think. This is because our concern is less with the commercial viability of IGCC, per se, as it is with the viability of carbon dioxide sequestration.

The whole purpose of acquiring IGCC technology rather than supercritical pulverized coal technology is to have the ability to sequester carbon dioxide at some future time at a lower cost than by adding this capability later to pulverized coal technology. Otherwise the benefit of IGCC in slightly higher efficiencies and slightly lower emissions is overshadowed by its additional cost and technology risk.

Unfortunately, it does not appear to us from our participation in the IGCC working group that sequestration techniques are close to becoming commercially viable and attendant costs and risks known. It appears that commercially viable sequestration may be far enough in the future that other technologies could become economically competitive in the interim. While we are not at this time opposed to pursuing a 2014 IGCC unit, we believe it is crucial to move forward with the three supercritical coal plants identified in this RFP.

It further appears that the current generation of supercritical coal units on the drawing board may be a necessary component of a bridge to the, as yet, undefined future. While these new plants could be in operation for years to come, it appears that they may displace older, dirtier units faster than these units would be retired without the addition of new pulverized coal technology.

Some of the technical work PacifiCorp undertook as part of IRP 2004 revealed an interesting phenomenon in this regard. At our request, PacifiCorp developed a resource portfolio with a larger ratio of coal to gas than other portfolios they had studied. One of the observations of the power cost run on this portfolio was that the existing coal units ran less. Older, dirtier, coal units were not backed down in other similarly-sized portfolios with a smaller coal to gas ratio.[5]

As currently configured, electrical systems require some large baseload plants. If cleaner more efficient baseload plants are not added, older, dirtier plants may be refurbished indefinitely. This is an issue that will require further study, perhaps in the context of the Climate Change Working Group.

2.3 Comparability of Power Purchase Agreements with Company-Owned Facilities

The Committee supports the Oct 4, 2006 RFP contracts, and we agree with PacifiCorp's response in their September 14 Reply Comments to the Independent Evaluator's (IE) suggestion to allow for comprehensive indexing of costs in third-party bids in order to provide comparability between power purchase agreements and Company-owned projects. In addition, we provide the following commentary.

As we understand it, the rationale for the IE's suggestion to shift risk to customers from power sellers is to equalize the risk faced by private developers and the utility. Since, the utility is able to pass forward prudently incurred costs, in an effort to equalize risk, the IE recommends allowing developers to index costs which would then be automatically passed through to customers.

The Committee is uncomfortable with this recommendation for several reasons. First, the Committee questions the assumption that all cost increases will be determined to be prudent and automatically borne by customers with little or no consequence to shareholders in the case of a Company-owned project. This ignores the rate setting process and the ability of parties to effectively question the legitimacy of certain categories of costs. However, if cost adders are included in PPAs, customers definitely will bear these costs without opportunity for review, since the contracts will be preapproved under Utah Code 54-17-303.

More fundamentally, we disagree with the proposal because it deviates from the principle that risk should follow reward. The proposal focuses only on the risk and not on the benefit or reward side of owning a facility. When a Company-owned project is constructed, customers may bear a significant share of the risk of increased construction costs, etc., but over time, customers receive the benefit of a depreciated facility that continues to provide power at cost-of-service. So the reward follows the risk.

In the case of a PPA, after the contract expires, there is no continuing benefit to customers. Instead, the facility owner reaps the reward. The owner possesses an asset that can be sold or has the ability to produce power to be sold at the then prevailing market rate. The load serving utility has to contract for additional power or build/acquire a new facility at then prevailing rates.

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[5] PacifiCorp, *Integrated Resource Plan 2004*, January 20, p. 134.

So, to shift the development risk of a PPA to customers is inappropriate. Customers should not bear the risk if the asset owner is to reap the reward. Furthermore, as PacifiCorp notes in its Reply Comments, customers presumably will have been supporting some portion of this risk through a higher rate of return, captured in the contract price, to compensate the owner for its higher risk structure.

Ironically, the proponents of introducing competitive forces into electricity production have argued that under a more competitive regime, IPPs would bear business risk, technology risk, etc, not customers. Now, in order to create a level playing field, customers are asked to continue to bear these risks but not receive the reward that comes from being the recipient of cost-of-service power from depreciated plant.

As one of the Committee's representatives noted during the September 21 Technical Conference, a tension between two objectives of the RFP process appears to exist. The first objective is to provide power to customers at the lowest reasonable cost taking into account a number of factors including risk. A second objective is to create a level playing field for power developers. The underlying assumption is that if a level playing field is created, customers will benefit.

The Committee is not convinced that this is the case. There are multiple reasons why an independent power producer may not be able to manage risk as effectively as a large, vertically-integrated utility with numerous and diverse resources, a broad transmission reach, and deep pockets—reasons that are separate from its ability to pass the buck to ratepayers. If an IPP cannot manage risk as effectively as the utility, then its costs will be higher. Therefore, requiring customers to bear additional IPP risk simply increases customer cost with no offsetting benefit.[6]

In this procurement process, the public policy objective of benefiting customers must be maintained. The procurement process should be a tool to assure that customers receive the best deal. Therefore, the risk profile facing customers should not be increased to assist IPP development.[7]

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[6] Other examples of the fallacy that customers will automatically and necessarily benefit from the introduction of competitive forces into electricity production can be found in the recent experience of attempts to deregulate the wholesale and retail electricity markets. The rationale underlying these efforts is to benefit customers. However, this is not necessarily the outcome. It is certainly not the outcome given the current cost structure of the electricity industry. Consider the wholesale electricity market. The rationale for deregulating this market was to lower prices to customers. However, even if the wholesale market can be made effectively competitive (which is questionable because of the inability to fully mitigate market power) customers will pay higher prices than under cost-of-service regulation. This is because in competitive markets, price is established by the cost of the most expensive resource operating. However, all existing resources with a lower cost structure (lower fuel costs, depreciated capital or both) such as hydro, coal, or nuclear power plants will receive revenues in excess of their costs. Under a cost-of-service regime, customers benefit from the lower cost structure of these resources. Under a deregulated regime, owners of the facilities earn excess profit. So, the idea that competitive forces will automatically benefit customers is exposed as a fallacy. While there are beneficiaries, they are not necessarily electricity customers.

[7] The proposal to shift producer risk to customers to level the playing field for producers appears reminiscent of arguments to promote competitive retail markets by increasing the standard-offer rate. After some states deregulated their retail electricity markets and competitive suppliers did not materialize, it was suggested that the problem resulted from too low of base rates. So, to attract alternative suppliers

3 CONCLUSION AND RECOMMENDATION

The Committee recommends that the Commission approve the RFP without modification to its benchmarked resources or contract structure as specified in the October 4, 2006 version of the RFP.

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and thereby promote competition, increasing standard-offer rates was recommended. These proposals turn the public policy objective of benefiting customers on its head. Instead of competitive forces being used as a tool to benefit customers through lower rates; customer rates become a tool to stimulate competition.