Before the Public Service Commission of Utah

In the Matter of the Application of PacifiCorp for Approval of a 2009 Request for Proposals for Flexible Resources	**))))**	**Docket NO. 05-035-47** **Responsive Comments of Merrimack Energy as Independent Evaluator**

Background

PacifiCorp originally filed a draft of its 2012 Request for Proposals (RFP) for Baseload Resources on June 11, 2006 (Initial RFP). Prospective bidders and stakeholders were eligible to file comments on the RFP by August 16, 2006. Five parties submitted comments. Merrimack Energy, the Independent Evaluator (IE) filed its report on the 2012 RFP on August 30, 2006 (August 30, 2006 Report), as required. A Technical Conference on the RFP was held on September 21, 2006 along with a Credit Workshop convened by PacifiCorp at the request of the Independent Evaluator (IE). At the Technical Conference, PacifiCorp and the parties discussed the schedule for the next draft of the RFP. On September 26, 2006, the Public Service Commission of Utah issued an Order revising the schedule in this proceeding. On October 4, 2006, PacifiCorp filed a new Clean version and a Redlined version of its Draft RFP (Revised RFP) consistent with the revised schedule. Responsive comments of all parties to the October 4, 2006 Draft RFP are due on October 13, 2006 with a Settlement Conference scheduled for October 19, 2006. The following are the comments of Merrimack Energy Group, Inc. as Independent Evaluator for the 2012 Request for Proposals.

Issues

The comments of the Independent Evaluator are focused on the revisions included in the Revised RFP based on the issues raised by the Independent Evaluator in its August 30, 2006 Report. Each of the key issues is addressed below. In a number of cases, PacifiCorp has made adjustments to the RFP to reflect the comments of the IE and other parties. Importantly, PacifiCorp has addressed many of the issues raised by the IE and others with regard to concerns that the RFP was not consistent with the acquisition of coal-based resources. References specifically oriented to gas-fired options have been addressed throughout the RFP document. As a result, the RFP document is more consistent with an RFP for both baseload coal and gas-fired options.

Comparability of Bids and Benchmarks: Cost of Service Principles and the Form Agreements

In the Revised RFP, PacifiCorp included redlined versions of the form agreements for the Power Purchase Agreement (PPA) and the Asset Purchase and Sale Agreement (APSA). As a threshold matter, we commend PacifiCorp for dropping the scoring for "Compliance with the Pro Forma" agreements in the Revised RFP (p. 49), as suggested by the IE in the August 30, 2006 Report (p. 69). Since most of the structural differences in risk between the forms and the Benchmark which existed as of the August 30, 2006 Report still remain with the filing of the Revised RFP, we believe bidders should be free, without penalty, to pursue additional changes to the forms in negotiations.

In the redlined PPA, PacifiCorp made several important changes as follows:

(i) in Section 10.1.2.5, a bidder-specified grace period for achieving the Commercial Operation Date was inserted[1];
(ii) in Section 10.7, edits were made, attempting to make the obligation to pay Net Replacement Power Costs consistent with traditional concepts of cover damages[2];
(iii) in Section 13.1, the definition of Force Majeure was changed to allow the possibility that a delay or failure to obtain Permits which Seller is diligently and timely taking all reasonable steps to obtain could qualify as an event of Force Majeure[3]; and
(iv) in Section 7.1, PacifiCorp has acknowledged our request that bidders be allowed to delay the posting of 100% of the Credit Support Security until construction financing.

Each of the above changes reduces the wide gap between the risks faced by Sellers under the PPA, on the one hand, and Sellers under the APSA and the Benchmark resource, on the other hand.

Although not yet addressed in the pro forma agreements, this wide gap in risk has been reduced in another critical way with respect to the risk of a change in the environmental laws. In the Revised RFP (p. 39), as well as in earlier drafts of the RFP, PacifiCorp has departed, in a significant way, from its general treatment of the change in law risk in the PPA. In general, PPA Sellers absorb the risk, and the cost consequences, of complying with changes in law that occur after the PPA is executed (see: Section 6.3.11 and Section 13.1(vii)). However, with respect to future costs, if any, of future tax assessments, or other impositions based on the quantity of carbon dioxide emissions produced from the combustion of fuel by a Project, "the bid evaluation process will incorporate the

[1] See: August 30, 2006 report at page 51.
[2] See: August 30, 2006, footnote 25, page 55. The IE believes further discussion is required to make Section 10.7 consistent with the definition in Section 1.1 of "Daily Delay Damages", which we believe correctly recognizes the need to subtract the value of Capacity Payments if unpaid. We take exception to how the algorithm in Section 10.7 now works.
[3] See: August 30, 2006 Report at page 52.

assumption that the Bidder does not contractually absorb the liability associated with potential future CO_2 expenses. **As such, even if the bid does not provide for the passing through of such costs, Bidders are directed to submit bids that specify the results of the assumption that Bidders <u>will pass through any costs</u> associated with meeting future air quality requirements relating to specified facilities.**" (Revised RFP, p.39, emphasis in original).

The IE views the risk of an environmental change in law as a major risk for any coal-based resource, including the Benchmark resources, which PacifiCorp may select. The above change in treatment for future tax assessments, or other impositions based on the quantity of carbon dioxide emissions produced, will assure that comparability will apply as to any such taxes or other impositions when selections are made under the criteria for selection in the Revised RFP.

The IE believes that this comparability is a valuable attribute for purposes of the Energy Resource Procurement Act, codified at Utah Code §§ 54-17-101 et seq. (the "Act"). However, it is not clear in the highlighted language whether the bid resources and the Benchmark resource will be treated comparably if the change in environmental law is a change which requires new capital expenditures in order to achieve compliance. A significant and unexplained gap in comparability will remain if PacifiCorp intends to draw a distinction between carbon dioxide based taxes and other assessments and other environmental requirements intended to accomplish similar objectives.

Based on the foregoing, the IE asks PacifiCorp to clarify the intent of the Revised RFP in this regard and to explain the basis for any distinction it may draw between its treatment of taxes and other assessments and its treatment of new environmental retrofits.

In the redlined APSA, a limited number of changes were made, the effect of which was to correct drafting errors in the earlier version[4].

In addition, in the Revised RFP, PacifiCorp has added a new substantive requirement for the performance of APSA Sellers and EPC Contractors at Currant Creek (Eligible Resources #'s 3, 4, and 5): each must operate and maintain the Project they construct for up to 10 years "to ensure cost effectiveness, availability and reliability of the resources prior to [PacifiCorp's] acceptance of the resource." (Revised RFP at pp. 6-7, 13, 15).

The IE will inquire at the Settlement Conference on October 19, 2006 as to PacifiCorp's reasoning in adding these new performance requirements for the specified Eligible Resources. The IE needs further information in order to assess this change and does not want to speculate concerning PacifiCorp's objectives. However, in order not to discourage potential bidders, we recommend that PacifiCorp provide at least a proposed Term Sheet for the major provisions of the anticipated Operations and Maintenance

[4] See, for example, Sections 4.9(c), 4.12(c), 4.19(c), 6.2(b), 10.2(c)(i), 20.6(f), 30.1(a), and 30.3(a) and (b).

Agreement (O&MA) so bidders may accurately assess the impact of the requirement on their bids[5].

With respect to the comparability of bids and the Benchmark resources on risk issues, we discern, based on the limited changes adopted in the Revised RFP, that the following differences in risk remain in place:

- <u>Milestone and Development Risk</u>. Both PPA Sellers and APSA Sellers have duties to meet applicable Milestones and achieve completion of the Facility or face contract consequences for delays or failures in performance, such as delay penalties and risk of termination. Differences in the risk levels between these two Sellers have been reduced significantly in the Revised RFP, but some differences, such as the treatment of required Project documentation, remain. On the other hand, for the benchmark options, no milestone or commercial operation deadlines, as such, apply under traditional cost of service principles. Even if schedules and target dates slip, as long as PacifiCorp continues to review alternatives prudently, and then prudently decides to continue, it will be entitled to finish the benchmark project without interruption and seek to recover its costs in rates. Accordingly, under traditional cost of service principles, ratepayers will experience the full impact of delay costs prudently incurred when a benchmark project cannot be finished on time. Many of the delay costs prudently incurred by PPA and APSA Sellers will, on the other hand, be absorbed by those Sellers.

- <u>Delay Damages</u>. In the case of both PPAs and APSAs, the delay damages are collected from Sellers[6] and serve to offset the losses incurred by Buyers when replacement power must be purchased due to the late completion of the PPA and APSA projects. To the extent of such damages, ratepayers are in theory protected from the excess cost of replacement power over project costs. For the benchmark options, provided that delays are outside the utility's control and the utility prudently adapts to the delays, cost of service principles would not require that the utility experiencing the delay in the benchmark completion date absorb the extra costs, if any, associated with purchasing replacement power during the delay period. Ratepayers in theory are chargeable for the consequences of prudent delay under cost of service principles.

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[5] Unless PacifiCorp intends to change the payment provisions of the applicable Pro Forma agreements, it appears that no counterparty offering any of the specified Eligible Resources will have significant capital at risk during the term of the O&MA. As a result, The IE questions how PacifiCorp intends to fashion contractual incentives in the O&MA "to ensure cost effectiveness, availability and reliability of the resources prior to [PacifiCorp's] acceptance of the resource." If PacifiCorp intends to expose bidders for such resources to contractual risks during operation comparable to those of Sellers under the PPA, The IE seeks guidance how this will be accomplished in order to assess this change.

[6] Under Section 2.3 of the PPA, Seller is required to pay defined Daily Delay Damages if the Commercial Operation Date occurs after the guaranteed date. Under Sections 24.2(c) and 24.3 of the APSA, Seller is required to pay daily Critical Milestone liquidated damages and daily Late Substantial Completion LDs ($50,000 per day for dispatchable Projects), respectively.

- Cost Increases due to Force Majeure and Change in Law. Under the applicable provisions of the APSA, Buyers as agents for the ratepayers are exposed to a risk that costs may increase to reflect certain Force Majeure and Change in Law events or occurrences. Under the PPA, no comparable risk exists for Buyers as agents for the ratepayers under the PPA. Compare: Sections 5.1.2 and 6.3.1.1 of the PPA to Sections 10.1, 10.3(a), 13.2(b), 13.2(c), and 28.3 of the APSA. For the Benchmark resources, under traditional cost of service principles, events outside the control of the utility, including, in particular, force majeure events and changes in law, would not result in imprudence disallowances as long as the utility continued to adapt its development efforts to the changed circumstances in a prudent fashion. As a result, permit opposition and delay, changes in law relating to environmental control requirements, and other similar occurrences would result in prudently incurred delay and scope-change costs being passed on to ratepayers for the Benchmark resources[7].

- Capital Cost Increases for Other Reasons. Sections 10.1, 10.3(a), 13.2(b), 13.2(c), and 28.3 of the APSA may, under certain circumstances, result in capital cost increases to APSA Buyers, and in turn to ratepayers taking service from such Buyers. Events during the Term of the APSA, such as changes to the cost of the electric interconnection or the fuel infrastructure, could cause a change in the Scope of Work and an associated increase in the final capital cost incurred by APSA Buyers. Like most construction-based contractual forms, the APSA contains Change Order procedures which contemplate price and other adjustment to the original contract terms[8]. Accordingly, APSA Buyers are exposed to risks of capital cost increases, both before and after the Commercial Operation Date, which are simply not applicable to PPA Buyers under Sections 5.1.2 and 6.3.1.1 of the PPA. Under traditional cost of service principles, provided that planning and construction exhibit prudence, Benchmark resources which experience capital cost increases during development or construction enter rate base at the higher costs resulting from such increases. Ratepayers are expected to absorb the risk of such prudent capital cost increases.

- Unavailability and Replacement Power Costs. After the Commercial Operation Date, PPA Sellers are exposed to the risk of reductions in their Capacity Payments under Section 5.1.2 to the extent their monthly unexcused hours of unavailability exceed allowed margins. The defined Events of Default create additional risk of default and termination for unexcused unavailability by PPA Sellers (Sections 10.1.2.2, 10.1.2.8). Payment reductions flow to the benefit of PPA Buyers as agents for ratepayers which can use the savings to fund the cost of replacement

[7] PacifiCorp has agreed in the 2012 Draft RFP that the risk of a change in law which imposes a carbon tax should be, under the PPA, the APSA and the Benchmark resources, absorbed by PacifiCorp on behalf of its ratepayers. This facially prudent decision has not, however, been reflected in the explicit provisions of the pro forma contracts.

[8] See, e.g., Section 7.21 (Spare Parts available by Change Order); Section 10.3 (Buyer Initiated Change when Buyer rejects an updated Seller Project Schedule); Sections 13.1(c)(iii), 13.2(b), 13.2(c)(i) (Change in Applicable Law/Permit or Site Condition), 13.2(c)(ii) (Suspension of Work by Buyer), and 13.2(c)(iii) (Non-Performance by Buyer).

> power. When termination results from unavailability defaults, PPA Sellers are exposed, under Section 10.7, to conventional contractual cover damages designed to protect ratepayers from absorbing the excess cost of replacement power. For Benchmark resources, on the other hand, provided that operating problems do not arise from imprudence, availability shortfalls, under traditional cost of service principles, would not result in either a reduction in the rate base recovery of the Benchmark capital costs or the inability of the utility to recover the full costs of replacement power from ratepayers. Ratepayers are expected to absorb the risk of prudently incurred replacement power costs[9].

Based on the foregoing, the IE continues to believe that common risk principles do not exist between the PPA resource, on the one hand, and the APSA and Benchmark resources, on the other hand. Different products with materially different risk characteristics are being solicited by PacifiCorp in the Revised RFP. Furthermore, these material differences in risk may have associated and differing effects on reliability and the financial condition of the utility, in both the short and the long term.

Having reviewed the price evaluation methodology in the Revised RFP, the IE also understands that the material differences in the risk characteristics described above are not modeled and analyzed by PacifiCorp in its bid evaluation.

As set forth in the August 30, 2006 Report (p.30), the Act, as applied to the facts of this Draft RFP, controls this assessment by the IE. The Act creates a public interest standard for Commission review and approval of this Draft RFP in UCA § 54-17-201(2)(c)(ii) as follows:

> "In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:
> *   *   *
> (ii) is in the public interest taking into consideration:
> (A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;

[9] Similar to the Benchmark resource, it is generally the case that ratepayers would absorb the risk of unavailability problems during operation of the Project for APSA resources. By its terms, the APSA has been performed and is not longer in effect when the majority of the operating period under the PPA is occurring. See: Section 6.2(b) of the APSA where the APSA Seller's primary liability for direct damages is described as the payment of the excess of the cost to replace or otherwise to have performed the Work over the Contract Price. See also: Section 29.4 where Buyer's spectrum of remedial rights and damages are set forth, none of which includes the obligation to cover the excess replacement cost of power. Accordingly, PacifiCorp's introduction of a 10 year O&MA requirement for APSA Sellers suggests that APSA Sellers may bear some responsibility for operating problems and shortfalls. However, it is unclear how the O&MA will be structured and the extent to which it will provide APSA Buyers as agents for ratepayers protection against the excess costs of replacement power when the Project is not available for operation.

(B) long-term and short-term impacts;
(C) risk;
(D) reliability;
(E) financial impacts on the affected electrical utility; and
(F) other factors determined by the commission to be relevant."

The IE believes, based on the existence of material differences in risk associated with the resources being evaluated, that PacifiCorp should now explain how the Revised RFP will fairly assess and take into account, in accordance with the requirements of the Act, these material differences when the final selection of resource(s) is made under the Revised RFP.

Pricing Adjustment Mechanism

Related to the comparability issue above, the IE raised concern about the pricing risks associated with long lead-time capital-intensive resources such as coal projects. As noted in the August 30, 2006 Report (pages 37-38), given the long lead-times for coal projects, requiring bidders to "lock-in" their capacity price at the time of bid submission contains significant price risk and represents a competitive disadvantage for third-party bidders when comparing such bids to a cost-of-service based self-build or benchmark option. Such a requirement may mean that bidders will either price in the cost uncertainty risk to their bid or decide not to compete in the process, particularly given the presence of the utility benchmark option and the different cost treatment (i.e. cost of service pricing) for such an option. The IE therefore suggested in its August 30, 2006 Report that PacifiCorp allow all bidders (including the benchmark options) to offer either a fixed capacity pricing mechanism or to index certain components of the capacity price to reflect changes in specific cost components (e.g. costs tied to a steel index, labor index or a producer price index for specialized metals) from the time the bid is submitted until the time the Engineering, Procurement and Construction contract (EPC) is executed, the bidder achieves financing, or the project achieves commercial operations. For example, once the EPC contract is executed the capacity pricing mechanism is then fixed for the term of the contract. The objective of this proposal was twofold: (1) allow bidders the opportunity to match components of their capacity price with costs until the EPC is executed or one of the other identified milestones is achieved and (2) to place third-party bids and self-build options on a more level playing field. Otherwise, third-parties may not bid or will price in such risk and be at a significant cost disadvantage relative to cost-of-service based options that are generally able to recover unexpected cost increases in plant construction that can be justified.

In its Reply Comments (pages 2-6), PacifiCorp raised a number of issues refuting the IE's comparability concerns. With regard to the price adjustment mechanism, PacifiCorp stated that "while the IE's suggestion for indexing is creative and provocative, the proposal does not take into account the traditional regulatory principles to which PacifiCorp is subject. Because these principles would not permit PacifiCorp to achieve regulatory approval for multi-million dollar generation projects with comprehensively indexed and undefined costs, it is not appropriate to solicit bids of this nature in this RFP”[10].

However, in our review of PacifiCorp’s revised RFP, it appears that PacifiCorp has agreed to allow an indexed pricing mechanism for the bidders’ capacity price. For example, on page 7 of the Revised RFP it is stated “Power purchase bids must be for a fixed term at a stated price which may be indexed or vary in price by year from a single resource located in or into PACE, and must be in the form of the Power Purchase Agreement.” Also, on page 20 of the Revised RFP, it is stated “To the extent the pricing is tied to or subject to market indices changes the Bidder must identify which components of their capacity prices are subject to these movements and what triggers will effectuate these changes and when pricing will be fixed.” Finally, in Form 1 Pricing Input Sheet, Lines 19-21 allow bidders to provide a monthly capacity payment as well as an annual escalation index.

The IE, therefore, assumes PacifiCorp has agreed to adopt a price indexing mechanism for capacity payments. The IE believes that the RFP language should be more explicit for bidders, to inform bidders of their options and identify any constraints or limits regarding the amount of the capacity payment eligible for indexing (i.e. only those components of the capacity price that are tied to specific cost indices) as well as the timeframe over which indexing is allowable (i.e. until execution of the EPC contract, until commercial operations or throughout the contract term). For example, to provide a reasonable balance in risk between the additional cost exposure for customers if some portion of the costs are tied to an index and the risk to suppliers, the IE would recommend that the timeframe for indexing components of the capacity price would be limited to the execution of the EPC contract or project financing, as selected by the bidder, but no longer than two years after contract execution. We would also recommend that no more than 50% of the initial capacity price would be indexed. At least 50% of the capacity price would therefore have to be fixed at the time the bid is submitted. The IE feels that such a mechanism minimizes risk to the customers, provides a reasonable balance in linking project cost to pricing, and should served to encourage bidders to compete in the process since third-party projects would be more consistent with the benchmarks.

In the IE’s view, if PacifiCorp has agreed to pricing comparability as noted above, the only issues remaining would be structural in nature as identified in the above paragraph. These issues should be discussed at the settlement conference. If the pricing comparability issue is still open, the IE suggests that the parties consider the alternative bid pricing mechanism identified by the IE in both its initial Progress Report of June 2006 (page s 4-5) and in the August 30, 2006 Report on the RFP (page 38). A more detailed description of this option is presented in Attachment A to these comments.

[10] PacifiCorp’s argument may prove too much if viewed as supporting as a statutory goal comparability of principles on which bids and the Benchmark resource compete. Thus, comparability could be achieved by allowing bidders to participate on the same basis as PacifiCorp, i.e., on cost of service contracts. In addition, in our experience, most regulators, when presented with the issue, have endorsed performance based ratemaking, which often includes indexed pricing, as consistent with principles of just and reasonable rates.

Credit Issues

PacifiCorp has made significant progress on credit issues from the Initial RFP and has developed a credit methodology which the IE believes should be fair, equitable, and balanced to all bidders and should not discourage bidders from competing in the process on the basis of credit requirements. The IE commends PacifiCorp for developing a thoughtful and creative approach for establishing credit requirements for bidders by type of resource alternative, recognizing the implications of credit rating, bid size, and commercial operation date in the calculation of credit requirements. Since credit issues have such an important bearing on the success of a competitive bidding process, PacifiCorp's response in this area is an important step forward.

In the initial RFP, PacifiCorp provided little information on credit requirements, which the IE identified as a key issue in ensuring the competitive bidding process is fair and equitable. The IE suggested in its August 30, 2006 Report (pages 44-46) that PacifiCorp hold a Credit Workshop for bidders and interested parties to present its suggested credit matrix and methodology and solicit questions and comments from bidders. On September 21, 2006 PacifiCorp held a Credit Workshop following the Technical Conference. At the Credit Workshop, PacifiCorp provided a copy of its presentation on credit requirements and development of the credit matrix, the methodology for determining security requirements and the types of security acceptable. The IE commends PacifiCorp for the high level of transparency and openness provided to bidders regarding the Company's methodology for determining credit requirements.

In addition, PacifiCorp provided substantial support underlying its credit methodology including a description of the factors that influence its credit risk profile. Overall, the IE believes that the level and type of security required should not discourage bidders from participating in the process. In fact, bidders are not limited based on their credit rating, size or financial conditions. Bidders with below investment grade credit ratings will be required to post higher levels of security to reflect their higher level of risk. Also, the approach taken by PacifiCorp to distinguish asset-backed from non-asset backed agreements is a significant step forward and reflects the differences between power marketer financial arrangements and power contracts based by hard assets, such as the assets expected in this RFP.

Based on review of the credit information provided by PacifiCorp, there appears to be two remaining outstanding issues:

1. At the Credit Workshop, PacifiCorp agreed to provide support for its estimate of the price of power for the replacement period of $155.49/MWh. This price reflects the market volatility estimates and influences the calculation of the credit support amounts.

2. For alternative B9a (Load Curtailment), the IE recommended that the level of security should be based on a $/kW basis rather than on a total dollar basis for

increments of 25 MW. Given the size of these resources it is the IE's view that smaller projects would be biased by the relatively higher credit requirements levels. For example, a 10 MW project would be required to post the same amount of total security as a 25 MW project. On a relative basis, the smaller project would be required to post a very high level of security on a $/kW basis. The IE therefore recommends that from a fairness standpoint and to minimize size bias, all bidders in this category should be required to post a total amount of security as the product of the project size times a fixed level of security on a specified $/kW basis (e.g. $50/kW). PacifiCorp indicated it agrees with the IE on this issue.

Debt Imputation

In its Report on the RFP, the IE noted that there was disagreement among the parties regarding the use of imputed debt for bid evaluation. There also seemed to be disagreement with PacifiCorp and other parties regarding the Commission's intent in Docket No. 03-035-14. The IE requested that the Commission either reaffirm its decision in Docket No. 03-035-14 or address the use of debt imputation in this docket to provide prospective bidders with pertinent information about the bid evaluation process (pages 47-48).

The Division stated that it believes that the position taken by the Oregon Commission (in Order No. 06-446, August 10, 2006) is reasonable and that debt imputation should not be used in the first round of the evaluation. The Division also believes that it is reasonable to require PacifiCorp to obtain an opinion from a ratings agency in the final round as evidence of the appropriateness of using debt imputation in the evaluation process.

In its Reply Comments (pages 9-10), PacifiCorp views the Commission's decision in Docket No. 03-035-14 to address only QF options. PacifiCorp states that while the Commission refused to permit QF payments to be reduced by the cost associated with imputed debt, virtually all the evidence in the QF case addressed the debt imputation issue specifically in the QF context and did not address the issue generally or in the context of larger PPAs for base load resources. PacifiCorp concludes that the QF Order does not control the issue with respect to the 2012 RFP. In its Reply Comments and in the Revised RFP, PacifiCorp has eliminated the application of debt imputation as a consideration in determining the short-list. While PacifiCorp states on Page 25 of the Revised RFP that it will take into account a cost associated with direct or inferred debt as part of its economic analysis in the final screening, we assume this means "Final Short-list". The IE requests PacifiCorp to confirm this interpretation.

The IE recognizes that the Oregon Public Utilities Commission has addressed debt imputation in its Competitive Bidding Guidelines (Order NO. 06-446). While the IE believes it is important for the Commission to reaffirm or address its position with regard to debt imputation in this case, the IE could support the position of the Division with regard to both the requirement that PacifiCorp not apply debt imputation in the first round of the evaluation and that at the request of the Commission PacifiCorp will be required to obtain a written advisory opinion from a rating agency to substantiate the utility's analysis and final decision. The written opinion from the rating agency should address the necessity for PacifiCorp to add equity as a result of imputed debt, and the amount needed, in order to avoid a credit derating caused by the additional debt associated with the Power Purchase Agreement under evaluation.

Code of Conduct

Subsequent to the issuance of the initial RFP, PacifiCorp prepared a Code of Conduct which governed PacifiCorp's intra-company relationships for the RFP 2012 process. The IE reviewed the proposed Code of Conduct and raised a number of concerns, particularly related to the roles of the Bid Evaluation Team and the Benchmark Team. The IE stated that PacifiCorp should ensure separation of the Benchmark Team from the Bid Evaluation Team. Members of the Benchmark Team should not be allowed to provide any services to the Bid Evaluation Team as PacifiCorp had included in its original Code of Conduct. In essence, it is the view of the IE that the Benchmark Team should be treated as any other "bidder" from a fairness perspective. If all bidders, including the Benchmark option, have the ability to refresh their bids, such a defined separation is necessary to ensure the process is undertaken in a fair and equitable manner with no threat that the Benchmark Team unfairly possessed, and potentially applied when its option was refreshed, proprietary information regarding other bidders. In its August 30, 2006 Report, the IE included a marked-up version of the Code of Conduct which addressed the above issues (pages 96-102).

In its Reply Comments (page 6), PacifiCorp indicated it would agree to the IE's suggestion to separate the Bid Evaluation Team from the Benchmark Team and to revise the Code of Conduct accordingly. In response, PacifiCorp included a revised Code of Conduct in its Revised RFP.

The IE is in general agreement with the revisions to the Code of Conduct proposed by PacifiCorp, with a few exceptions. In the Code of Conduct, under the Section entitled Evaluation Team, it is noted that "The IRP work group will not share any information it obtains from either Team with the other Team until after the final short list …". Taken literally, this would mean that after the final short list, the IRP work group could convey to the Benchmark Team proprietary information about bids it received from the Evaluation Team. Such a transfer of proprietary information must not occur, in our view, at any time. Furthermore, in the section entitled Benchmark Team, there is a statement that "the Benchmark Team may utilize the IRP work group to model benchmark portfolios". The IE questions why this is necessary since the benchmark resources have already been identified. Furthermore, unless PacifiCorp can provide a reasonable explanation why such an option is necessary, it would appear that this opportunity conveys a benefit to the Benchmark Team not available to other bidders. Unless explained, conforming edits would be required in subsection 3 of the Section entitled Evaluation Team.

Requirements for Variable Interest Entity Treatment

The IE concluded in its August 30, 2006 Report (pages 46-47) that PacifiCorp's requirement that proposals that trigger Variable Interest Entity (VIE) treatment be prohibited from the competitive bidding process is reasonable and is consistent with industry standards and trends. However, the IE wishes to clarify that if PacifiCorp rejects a proposal as triggering VIE treatment that PacifiCorp provide documentation to the IE detailing the basis for its decision.

Non-Price Evaluation Criteria

In its Initial RFP, PacifiCorp proposed conducting a price and non-price evaluation of eligible bids for the basis of selecting a short-list. The price/non-price weights proposed were 70% price and 30% non-price. While such weightings are more skewed toward price than is traditional in other RFPs, the IE's view was that the Bidder qualification process also addressed non-price considerations associated with bidder experience and financial capabilities that are included in the non-price criteria in other RFPs.[11]

In the Revised RFP, PacifiCorp accepted the suggestion of the IE to eliminate the non-price criteria entitled "Compliance with the Pro Forma Agreements Non-Price Weighting Factor". The two remaining non-price factors were (1) Development, Construction and Operational Experience and (2) Site Control. Each major factor has a weighting of up to 10%. Thus, the proposed weightings in the Revised RFP are now 80% price and 20% non-price, which is even more skewed toward price.

In addition to weighting issue, the IE has two other concerns with regard to non-price factors. First, the IE feels that some of the information requested by PacifiCorp for the non-price evaluation and the Bidder qualification process is inconsistently organized and should be revised. Second, the IE believes that the non-price criteria should be expanded to include more non-price factors. Each of these concerns will be addressed in more detail below.

With regard to the Bidder qualification process, it would appear that the objective of PacifiCorp is to assess bidder qualifications, bidder experience and bidders capability for successfully developing and operating a project. The focus on the Bidder qualification stage is on the bidder. The focus at the non-price evaluation stage should be on the project proposed. In other RFPs, common non-price factors include: (1) Flexibility (i.e. variation in in-service date, flexible contract term, etc.); (2) Development Feasibility (i.e., siting, environmental permitting status, project schedule, engineering design, fuel supply and transportation arrangements, right-of-way acquisition, water supply availability, etc.); (3) Project Operational Viability (i.e., O&M plan, environmental compliance, fuel reliability, environmental impact, etc.); and (4) Quality of Output (i.e. dispatchability, operating profile, coordination of maintenance, etc.). The majority of these factors pertain to the success of the project. Thus, the IE recommends that PacifiCorp consider revising

[11] For most RFPs, the typical weightings are 60% price and 40% non-price for the initial short-list evaluation.

its pre-qualification information based on the bidder requirements and non-price information based on the specific project underlying the proposal. These factors are particularly pertinent for assessing the feasibility and viability of new generation options, such as coal, gas or other power generation projects. In addition, as previously noted, we would encourage PacifiCorp to expand the non-price criteria and add non-price factors to allow for more resolution among bidders.

The IE would recommend the following changes to Appendix A and B of the Revised RFP:

- The information requested under Section 3. Bidder Experience in Appendix A is more project specific than bidder specific and should be moved to the discussion of non-price criteria since much of the information requested pertains to the project (i.e. "please describe the status of all activities to fully develop and/or implement the project, such as negotiations for partnership agreements, equipment supplier agreements, EPC agreements, fuel supply agreements, permitting, financing, etc). For example, the feasibility and viability of the project are dependent on the above factors but these factors generally do not influence whether the bidder is capable of developing the project.

- The information requested under Section 4. Bidder Capability in Appendix A should be moved to the discussion on non-price criteria, similar to the suggestion above.

- In place of the information requested in Appendix A, as noted above, the IE recommends that PacifiCorp request information such as:
  - Provide a list of other projects the bidder has successfully developed including the name of the project, location of the project, project type, size and technology, commercial operation date, and bidder's role in the project development process.
  - Provide a list of projects the bidder has successfully operated.
  - Provide a list of projects financed by the bidder including the date of financing, the capital structure, debt and equity providers, and capital structure.

- For Appendix B, add the following question; "Bidders should demonstrate their ability (and/or the ability of their credit support provider) to provide the required security, including its plan for doing so (including type of security, sources of security, and a description of its credit support provider)".

The non-price criteria listed on page 37-38 of the Revised RFP should be revised to reflect issues associated with success of the project. Instead of referring to the first non-price criteria as "Development, Construction and Operational Experience" the criteria should perhaps be "Development, Construction and Operational Feasibility". There are two options that PacifiCorp could follow: (1) separate Development/Construction and Operations and include 10% weighting for each or (2) utilize the same categories but expand the weightings. A number of traditional non-price criteria could be addressed under this category including:

- Project critical path schedule
- Status of environmental permits/identification of permits and the strategy for securing permits
- Engineering design for the project
- Water supply availability
- Right-of-way acquisition
- Fuel supply and transportation access
- Financing plan
- O&M plan
- Environmental compliance/strategy[12]

Alternatively, PacifiCorp could include several of the above criteria (i.e. critical path schedule, permitting status, right-of-way acquisition) in the Site Control and Permitting Category. With expanded criteria, it may be possible to expand the weightings to 25-30% for non-price factors, if necessary.

The IE could provide PacifiCorp with non-price factors used in other RFP processes, if required. In addition, the IE would be available to assist PacifiCorp with any further red-lining of the RFP necessary to conform the RFP to the recommendations contained herein.

Contract Flexibility Provisions

The IE suggested (pages 35-36 of the August 30, 2006 Report) that due to the uncertainty associated with the amount and timing of the need for power, the technology uncertainty associated with IGCC projects, and the uncertainty over implementation of carbon taxes and other possible environmental requirements, such contract flexibility provisions as contract buyout options and in-service date deferral options may add value to PacifiCorp and its customers to manage risk and cost exposure. In its Reply comments (page 7), PacifiCorp agrees that such options are appropriate and will incorporate language in the Revised RFP. The IE has provided PacifiCorp with information pertaining to such flexibility provisions from other RFPs and industry documents. PacifiCorp has included language on page 2 of the RFP addressing these issues and directs bidders to use Form (if offering contract in-service date deferral) and Form 2 (if offering a contract buyout).

[12] In its Comments of August 16, 2006 in this proceeding, Western Resource Advocates (WRA) "recommended that the RFP should explicitly include as evaluation criteria whether bids to construct new generating facilities will be designed to be carbon capture ready and whether the facilities have been sited with ready access to sequestration opportunities. Bidders should be put on notice that failure to account for these evaluation criteria may serve as grounds for rejection of the bid. WRA believes it would be unwise for the Company to enter into long-term agreements with any project that does not demonstrate a long-term strategy for managing its CO2 emissions." Environmental compliance considerations as mentioned by WRA have been used as non-price criteria in other RFPs. Also, Public Service Company of Oklahoma's December 2005 RFP for Baseload Resources included a table for bidders to provide information on CO2 Capture Cost under several different retrofit arrangements.

However, while PacifiCorp has included a reference to such options on page 2 of its Revised RFP, the IE still feels this section and the associated Forms need addition work. For example, the IE could not identify the sections in Form 1 which pertain to the deferral option. The IE would suggest either including an additional schedule in Form 1 that clearly identifies the information required pertaining to the deferral option (i.e. matrix that includes an entry for the deferral option premium based on contract milestone dates and the option period, such as a one or two year deferral option) or providing detailed language requesting bidders to describe their deferral options. Also, it is stated on Page 2 that bidders proposing a buyout option should refer to Form 2. While Form 2 does include the milestone dates at which the bidder could propose the Break-up Fee or amount of the buyout option, there are a large number of milestones included on Form 2. Perhaps PacifiCorp could identify 3-4 milestones that may be appropriate for bidders to respond to (i.e. signing of the contract, prior to securing permits, prior to securing financing, execution of the EPC contract). This would allow for a more manageable process and would be consistent with the key milestone events at which the bidder would begin to incur costs. The concept behind the buyout option is that the cost of the buyout should reflect the development costs to date. If the milestones are limited, the bidder would be able to more accurately project such costs and offer a more reasonable buyout cost. The IE has added language to this section of the RFP to begin to address this issue.

Modeling Issues

In the August 30, 2006 Report, the IE proposed an alternative approach for addressing concerns raised by a party requesting access to the Company's models. While the IE indicated that it was not common practice for utilities to share proprietary models with bidders and could lead to chaos in the process, the IE proposed an alternative whereby the Division or Commission staff could identify a limited number of alternative scenarios that it would like to see considered in the evaluation process. The IE would serve as the liason between the Division and Commission staffs and the Company in effectuating the analysis. The Company did not address this issue in its Reply Comments.

Conclusion

PacifiCorp has made a number of improvements to the 2012 RFP that address many of the concerns of the IE and other parties. There are only a few issues that need to be clarified and resolved. The IE looks forward to discussing these issues with the parties at the Settlement Conference on October 19, 2006.

Respectfully submitted on this 13th day of October, 2006.

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Merrimack Energy Group, Inc.
Independent Evaluator

Attachment A

Alternative Power Procurement Process for Baseload Resources

In both its First Progress Report issued in June 2006 and in the Report of the Independent Evaluator Regarding PacifiCorp's 2012 Request for Proposals for Base Load Resources (August 30, 2006), the Independent Evaluator raised concerns over cost exposure associated with base load resource options and suggested options for addressing potential inequities in evaluating base load options. In the First Progress Report of the Independent Evaluator, the IE stated (as modified):

> In other competitive bidding processes, both the utility and independent developers have raised concern over such cost exposure. From the utility perspective, the concern is the risk of disallowance if costs are ultimately much higher than anticipated (even under cost of service pricing). For the third-party developer, the concern is the traditional requirement in the RFP that the bidder fix" its price or "lock-in" its capacity payment at the time of bid submission. Since the third-party bidder will ultimately be paid under contract on the basis of its bid price, the risk premium or cost of uncertainty is generally built into its bid price, thereby increasing its bid price and the potential cost to the consumer. This requirement potentially makes it more difficult for the third-party bidder to compete effectively against a utility coal option bid under a cost of service arrangement where the utility is generally able to recover prudently incurred cost increases for their project.
>
> Furthermore, while the third-party bidder may be required to lock-in its capacity price years in advance of either executing an Engineering, Procurement and Construction (EPC) contract and/or securing financing, utility projects are subject to cost-of-service regulations. If the utility is able to justify any cost increases above its bid or benchmark costs as "out of its control", such costs are generally recoverable. Likewise, if laws or regulations change (i.e. carbon tax or environmental requirement), the utility is generally able to recover such costs. On the other hand, while third-party bidders do not face a limited return as the utility does, the third-party bidder is able to achieve higher returns for taking such risk. However, it is also possible that the third-party developer would experience potentially much higher costs and lower return as well. With such capital intensive projects as coal-based options, the risk of higher costs in such an uncertain environment may discourage third-party proposals, create disincentives to bid, and lead to limited competition for utility benchmark options.

Merrimack Energy has identified several options for addressing the comparability issues associated with power pricing for baseload coal resources. One option identified by the IE followed the approach used by Public Service Company of Oklahoma (PSO). PSO, in its recent RFP, allowed utility self-build options and third-party bidders to index components of their capacity price to market indices such as inflation, steel prices, producer price indices, etc. either until execution of the EPC contract or other mutually agreeable milestones such as commercial operation. At that point the capacity price would be fixed for the term of the contract. The objective of this option was to allow a major component of the bid price (components of the capacity payment) to adjust to market indices until the EPC agreement is executed (for example). Bidders would then be able to more closely match the EPC costs to their bid prices without being subject to market vagaries and would thus face less price risk. Such an approach shifts more risk to the customers of the buyer but could lead to lower overall prices and more competition between the utility and third-party bidders. Without some mechanism to place bids on a more level playing field with utility self-build options, the IE is concerned that few bidders will choose to compete as the utility self-build option enjoys a competitive advantage by virtue of the RFP process.

In its Reply Comments filed on September 14, 2006 PacifiCorp takes exception to the use of indexing certain component of the capacity cost.

> PacifiCorp has several comments about this proposal. First, to the extent that it increases generation costs and risks to consumers, it is contrary to the underlying goals of the 2012 RFP and PacifiCorp's IRP. Next, absolute comparability between the Benchmark Resources and third-party bids is impossible, given the inherent differences between the two types of resource proposals. The fairness of the RFP can still be assured, however, through the presence of the IE and other features designed to ensure transparency and objectivity in the bid evaluation process. Finally, while the IE's suggestion for indexing is creative and provocative, the proposal does not take into account the traditional regulatory principles to which PacifiCorp is subject. Because these principles would not permit PacifiCorp to achieve regulatory approval for multi-million dollar generation projects with comprehensively indexed and undefined costs, it is not appropriate to solicit bids of this nature in this RFP.

While the IE understands PacifiCorp's concerns regarding the uncertainty of regulatory approval associated with indexed pricing formulas, the fact is that Commissions approve contracts with such indexed pricing arrangements or fuel market indices on a regular basis. While the IE still feels this option has merit for pricing of long-lead time resources, there is a possibility that the risk of cost increases could be shifted to consumers at the benefit of suppliers.

In its First Progress Report, the IE also provided an outline of another approach to developing a more level playing field for third-party projects and utility benchmarks. The IE believes this approach is consistent with the competitive negotiations process advocated by PacifiCorp. Under this approach, bidders and the utility self-build or benchmark options will be allowed to present two cost estimates for the capacity price components for each bid. This would include a base or best case price estimate (capacity cost only) and a price with contingencies that provide the bidder with a 95% confidence level for not exceeding such a price. Bid evaluation could be based on the average of the two prices or on both price estimates. If the second option is followed, bids will be ranked in the initial evaluation for both the base price and contingency price. The best bids on the basis of both pricing options will be eligible for the detailed evaluation. Prior to the detailed evaluation stage, PacifiCorp will allow short-listed bidders (including the benchmark bid) the opportunity to re-price at a level no higher than the contingency price. The revised price will serve as the basis for evaluation at the portfolio evaluation stage. Bidders on the short-list will have more time to formulate their price and will be more willing to spend development dollars if the bid is on the short-list.

PacifiCorp has noted that it intends to negotiate both price and non-price factors in its final evaluation and risk assessment. If the benchmark resource is the highest ranked option from a pricing standpoint, PacifiCorp will use the cost of the benchmark as the true benchmark cost for negotiation. PacifiCorp will negotiate with third-party bidders with the objective of negotiating a price/risk profile at a level lower than the benchmark option (although bidders will not know the cost of the benchmark option). If a third-party option is not able to provide a price/risk profile more favorable than the benchmark option, the benchmark will be the selected resource. The objective of PacifiCorp should be to get the best deal for the customer. If PacifiCorp's stated approach is to negotiate both price and non-price factors, using the benchmarks as the basis for negotiating the contracts would benefit the customers and also provide incentive for bidders to compete in the process. The IE will be present for the negotiation sessions to ensure the objectives of the process are followed.