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January 14, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UM 1182 – Reply Testimony and Exhibits of Stacey J. Kusters

PacifiCorp d/b/a Pacific Power submits for filing an original and five copies of the reply testimony and exhibits of Stacey J. Kusters.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No. 11-506).

Please direct any informal inquiries regarding this filing to Bryce Dalley, Director, Regulatory Affairs and Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith /BSD

William R. Griffith
Vice President, Regulation

Enclosures

cc: Service List UM 1182

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UM 1182, on the date indicated below by email and/or US Mail, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: January 14, 2013

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Coordinator, Regulatory Operations

REDACTED
Docket No. UM-1182
Exhibit PAC/200
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Stacey J. Kusters

January 2013

Q. Are you the same Stacey J. Kusters who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (the Company)?

A. Yes.

<u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. My testimony includes a rebuttal of the parties' direct testimony regarding the Guideline 10(d) analytic framework (Guideline 10(d) Analysis) used to compare bids for power supply contracts between the Company and third parties to a cost-based benchmark alternative (Benchmark Resource) during a competitive resource solicitation. My rebuttal is limited to a discussion of competitive bidding Guideline 10(d) and to the items identified by the Public Utility Commission of Oregon (Commission) in Order No. 12-324 to be addressed in this phase of the docket: 1) construction cost over- and under-runs; 2) heat rate degradation; 3) wind capacity factor; and 4) counterparty risk. I respond to the proposals and analysis presented by Mr. Procter on behalf of Commission Staff (Staff), and Mr. Monsen and Ms. Collins on behalf of the Northwest and Intermountain Power Producers Coalition (NIPPC).

Q. How is your testimony organized?

A. My testimony has five parts. The first part addresses the Guideline 10(d) Analysis and specifically responds to Staff's recommendations regarding the conceptual framework for this Phase II, as well as provides a response to NIPPC's proposals. The remaining four parts include rebuttal and further recommendations associated with each of the items to be initially addressed in this phase of the docket: 1) construction cost over- and under-runs; 2) heat rate degradation; 3) wind capacity factor; and 4) counterparty risk. For each item, I compare the risks and benefits associated with a Benchmark Resource and bids for third-party owned resources by applying the conceptual framework discussed in the first part of my testimony. In addition, for each item, I specifically rebut the analysis presented by NIPPC witnesses Mr. Monsen and Ms. Collins.

Q. Please summarize your testimony.

A. My testimony explains why it is important to focus Phase II of this docket on improving the Guideline 10(d) Analysis process and reducing the potential for bias rather than on the development of generic bid adjustments to be applied to future bid solicitations, as NIPPC proposes. With respect to construction cost over- and under-runs, heat rate degradation, and wind capacity factor, I describe in detail why generic bid adjustments are not in the best interest of customers and explain the flaws with the analysis presented by NIPPC witness Mr. Monsen. With respect to counterparty risk, I reiterate my position in direct testimony that the probability of default should be incorporated into the bid review process as well as describe why the testimony presented by NIPPC witness Ms. Collins is largely irrelevant.

<u>Recommendations for a Guideline 10(d) Analysis</u>

Q. Please summarize the recommendation made in your direct testimony.

A. I recommended improving the Guideline 10(d) Analysis *process*, which involves the independent evaluation of the Benchmark Resource (if any) and all or a sample of the bids to determine whether the selections for the initial and final shortlists are fair and reasonable, rather than focusing on the development of generic pre-determined bid adjustments. In addition, I recommended that compliance with Guideline 10(d) also include an evaluation of the unique risks and advantages associated with the Benchmark Resource (if used). I noted that the Company does not believe that focusing on the development of generic pre-determined bid adjustments will achieve the stated goal of developing a more comprehensive accounting and comparison of *all* the relevant risks.[1]

Q. Has your recommendation changed?

A. No. The Company continues to believe that generic pre-determined bid adjustments are neither advisable as a policy matter nor necessary as a means to fairly evaluate the risks and benefits of third-party owned resources with a Benchmark Resource. As will be described in more detail below, the flaws in the analysis and conclusions presented by NIPPC witness Mr. Monsen only serve to highlight the futility of attempting to generically pre-determine and pre-judge certain types of risks and benefits associated with different types of resources and acquisition structures. I continue to believe that the introduction of any level of generic bid scoring adjustments based on ownership structure is likely to distort the bid ranking process, introduce bias, and potentially increase cost and/or risk to customers.

[1] *See In the Matter of An Investigation Regarding Performance Based Ratemaking Mechanisms to Address Potential Build-vs.-Buy Bias*, Docket UM 1276, Order No. 11-001 at 6 (January 3, 2011) ("Order No. 11-001").

Q. In Staff's testimony, Mr. Procter concludes that the Commission's directive in Order No. 11-001 for Phase II was to develop a more in-depth analysis of risks that arise from selecting a utility's benchmark resource versus buying the output from an Independent Power Producer (IPP).[2] Do you agree with this conclusion?

A. Yes. The focus of Phase II should be solely on the development of a more in-depth analysis of the comparative risks and advantages that arise from selecting a utility's Benchmark Resource versus buying output from an IPP. I note that there is a multitude of different contractual structures to acquire power supply from third parties which adds complexity to such an analysis. For example, contract structures could include fixed or variable price power purchase agreements (PPAs), tolling agreements, or lease agreements, all of which will have different terms and conditions that create different types and degrees of risk to customers.

Q. Staff's testimony includes a proposed conceptual framework for Phase II. Do you agree that a conceptual framework for Phase II would be helpful?

A. Yes. Given the complexity of issues addressed in Phase II, a conceptual framework would aid the parties in both gaining a clear understanding of any future potential for bias to be addressed in Phase II and guiding the development of an appropriate response.

Q. What is Staff's proposed conceptual framework?

A. Mr. Procter recommends a conceptual framework for Phase II that is designed to address each of the three goals of Phase II, which Mr. Procter defines as: "(1) determine how the risks are addressed in bid evaluation, (2) determine what bias

[2] Staff/100, Procter/3.

exists, and (3) recommend adjustments to guideline 10(d) to account for that bias."[3] Mr. Procter also notes that the focus of the risk analysis in Phase II should be on risk to ratepayers.

Q. Do you agree with Staff's goals for Phase II?

A. Yes, in part. The Company agrees with Staff's goals in that the first and third goals seek to determine whether any adjustments to Guideline 10(d) in the competitive bidding guidelines are ultimately necessary, and to more clearly understand the risks and benefits associated with any proposal, whether they be Benchmark Resources or third-party owned resources. The key point is that only once the comparative risks are understood can appropriate evaluation criteria be developed for the Guideline 10(d) Analyses performed in future requests for proposals (RFPs). Therefore, the Company agrees with Staff that a goal of Phase II is to determine how the risks are addressed in Guideline 10(d) of the bid evaluation process. The Company also agrees with Staff that the focus of the risk analysis should be on risk to customers.

Q. Do you propose any modifications to Staff's goals for Phase II?

A. Yes. The second goal is not necessary. It will not be helpful or constructive to focus on determining what bias exists, if any, in the current evaluation process. This is because the focus need only be on ensuring that the process is fair and robust and eliminates, or reduces to the extent possible, the *potential* for bias in future RFPs. For instance, if there is concern that utilities will deliberately underestimate project construction costs for a Benchmark Resource—any actual occurrence of which has not been established and which I vigorously argue does

[3] *Id.*

not occur—the way to remedy this concern is to enhance the process to eliminate or minimize this possibility on a going forward basis.

Q. How does Staff propose determining what bias exists?

A. Mr. Procter states that the Commission is interested in Phase II in "systematically evaluating if the current bid evaluation criteria itself is structured in such a way as to result in bias."[4] Mr. Procter goes on to state:

> If it turns out that the existing bid evaluation criteria reasonably accounts for differences in risk between two bids, then that is evidence that the bid evaluation criteria are free of bias. In that case, changes to guideline 10(d) are not warranted. In contrast, if there are two bids that leave ratepayers exposed in substantively different ways to at least one of the four risks under investigation, and the bid evaluation criteria does not accurately account for this difference, then that is evidence that the bid evaluation criteria contains bias. In this case, changes in the guideline 10(d) are warranted.[5]

Q. Do you agree with this?

A. No, I do not agree with this to the extent it requires mining historical information and attempting to establish whether or not bias existed in prior RFPs. Focusing on arguments that attempt to establish the existence of bias in prior RFPs is not constructive because: 1) the potential for future bias is relevant, and, as such, the potential for future bias is not demonstrated by allegations of prior bias; and 2) it would involve a burdensome *post hoc* evaluation of historical resource selections, many of which have already been reviewed and approved by Independent Evaluators ("IE") and the Commission in a ratemaking proceeding. As I explain in greater detail below, the comparative risks associated with different resource

[4] Staff/100, Procter/7
[5] *Id.*

options are highly dependent on the facts specific to a particular bid solicitation and the nature of the bids received in response to that solicitation. Furthermore, the risks faced by both utilities and third parties in developing new resources can change significantly given external factors that include economic conditions, natural gas prices, commodity prices, materials costs, global supply/demand for major components, lead time on critical path equipment, labor costs, technological advancements, and general supply and demand for engineer, procure and construct (EPC) contractors.

Q. Do you believe the Guideline 10(d) Analysis could improve?

A. Yes. Efforts could be made to continuously improve the RFP process. It is also critical that any Guideline 10(d) Analysis be flexible enough to account for RFP-specific requirements as well as changes in industry trends. For the reasons more fully described below, requiring the IE to apply generic pre-determined bid adjustments to all future RFPs could result in resource selections that are not in customers' best interests.

Q, What is your recommendation for establishing a revised Guideline 10(d) Analysis?

A. Rather than instituting a Guideline 10(d) analytic framework that calls for the application of generic pre-determined bid adjustments to all RFPs (even where they may not be relevant), the processes set forth in the current competitive bidding guidelines can be utilized to develop an appropriate 10(d) evaluation for each individual RFP. The Commission's competitive bidding guidelines, specifically Guidelines 6 and 7, already provide a process whereby a Guideline

10(d) Analysis may be developed for each RFP. Guideline 6 requires the utility to, among other things, prepare a draft RFP and provide it to all parties and conduct workshops on the draft RFP.[6] Guideline 7 requires the solicitation of public comments on the utility's final draft RFP.[7]

Q. Why is it important to develop a Guideline 10(d) Analysis on an RFP-specific basis?

A. Each RFP is unique. For example, the evaluation of a renewable Benchmark Resource is different than the evaluation of a Benchmark Resource submitted as part of an all-source RFP. Exhibit PAC/201 is an example of a renewable RFP. Exhibit PAC/202 is an example of an all-source RFP. A comparison of these two exhibits demonstrates that the evaluation process used in each of these two RFPs is unique and establishing general pre-determined adjustments would not be applicable to each of the RFPs. An RFP-specific Guideline 10(d) Analysis can take into account the facts and circumstances of each individual RFP, including the market and available technologies at the time the RFP is issued.

Q. What is the purpose of Phase II if the Guideline 10(d) analytical framework should be developed on an RFP-specific basis?

A. The focus of Phase II should be on the Guideline 10(d) Analysis process. The outcome of Phase II can provide an outline and parameters for the development of RFP-specific analyses.

Q. In light of the foregoing, what is the fundamental flaw in NIPPC's approach?

A. NIPPC's proposed bid adjustments skip the important first step of assessing the

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[6] *See In the Matter of an Investigation Regarding Competitive Bidding*, Docket UM 1182, Order No. 06-446 at Appendix A, p.2 (August 10, 2006) ("Order No. 06-446").
[7] *Id.*

comparative risks associated with *both* the Benchmark Resource and third-party owned resources and determining whether any potential for bias exists. In other words, NIPPC proposes asymmetric bid adjustments to only Benchmark Resources without first demonstrating that such an approach is necessary or reasonable.

Q. Are there other basic problems with NIPPC's approach?

A. Yes, there are a number of erroneous facts and questionable assumptions included in Mr. Monsen's analysis that I describe in more detail below. In addition, a fundamental flaw with Mr. Monsen's analysis is that it is solely based on utility-owned resources. NIPPC simply fails to present any comparative evidence demonstrating that third-party bids associated with third-party owned resources do not also carry the potential for bias. Mr. Monsen fails to provide any evidence that third-party procurement practices and contractual requirements are more rigorous than a utility's. Considering only the risks of utility-owned resources without comparing them to risks of third-party owned resources captures only half the picture, and it also distorts bid rankings by introducing a pre-determined and guaranteed bias as matter of policy. Rather than evaluate the risks associated with Benchmark Resources and third-party owned resources, NIPPC assumes, without analysis or support, that Benchmark Resources pose higher risks to customers.

Q. What appears to be the basis for NIPPC's approach?

A. NIPPC appears to be leveraging the Commission's acceptance of the premise that a bias exists in the utility resource procurement process that favors Benchmark

Resources over entering into PPAs[8] as a means to conclude that a bias exists with respect to the four factors examined herein. NIPPC argues that the way to improve the evaluation process is to produce a Guideline 10(d) Analysis that is intentionally biased in *favor* of third-party owned resources. As a result, NIPPC's proposal introduces a bias against Benchmark Resources.

Q. Does this approach have the potential to harm customers?

A. Yes. NIPPC's approach assumes that a Benchmark Resource *always* has more risk than a PPA. If, however, this assumption is incorrect, customers are likely to pay more than what they would otherwise if a PPA is selected via an RFP process. Even if one accepts the unsupported premise that third-party owned projects are less risky to utility customers, generic bid adjustments do not act to ensure that the least cost, least risk resource is selected. Instead, as discussed further below, imposing bid adjustments on one group of alternatives may harm customers because the remaining bidders are then incented to increase their bid price.

Q. Does Mr. Monsen suggest an alternative to using bid adjustments?

A. Yes. Mr. Monsen suggests that if a particular bid adjustment is not used for a bid, the utility will bear the burden of demonstrating to the Commission (after opportunity for comment by the IE, Commission Staff, and non-bidding stakeholders) that the Benchmark Resource properly takes into account the potential cost increase addressed by a prospective bid adjustment.

Q. How do you respond?

A. Mr. Monsen's proposal is unworkable, for a number of reasons. This proposal would hinder an already lengthy and burdensome RFP process. To ensure a RFP

[8] Order No. 11-011 at 5.

is fair and equitable for all bidders, the bid adjustments would need to be removed from each bid for the analysis to evaluate the baseline and then reevaluate using any adjustments. It is hard to imagine that the process of having the IE review the Company's arguments against each adjustment could be completed expeditiously and not be without controversy from the bidders because the rules are not well defined and may change in the evaluation process. More fundamentally, any adjustments to the bid scoring should originate and be supported by the IE and be symmetrical. The current method of establishing a bid scoring methodology for a Benchmark Resource, which currently includes price and non-price factors as applicable, is *before* market bids are received. This effectively yields a fair and open RFP, which is vital for a robust response. Bidders would likely have concern—and reasonably so—over the prospect that the Company would be proposing lists of bid-specific adjustments after all bids were received. This may lead to a lack of participation and limited options for any future RFP. Finally, Mr. Monsen's suggestion does not appear to address the potential for a conflict of interest in situations where a non-bidder stakeholder is also an organization with members who may themselves be a bidder in the RFP process.

Q. Does this conclude the first part of your testimony?

A. Yes. I turn now to a discussion of each of the four factors at issue in this phase of the docket.

<u>Construction Cost Over- and Under-Runs</u>

Q. Please summarize your testimony regarding construction cost over- and under-runs.

A. NIPPC witness Mr. Monsen's analysis regarding empirical construction cost over-runs is based on inaccurate facts or misinterpreted assumptions, and further highlights why the attempt to develop generic pre-determined bid adjustments applicable in future RFPs is not advisable.

Q. What are the comparative risks associated with construction cost over- and under-runs for Benchmark Resources and third-party owned resources?

A. When the utility is able to negotiate a fixed price contract associated with a third-party owned resource or its output (which, as noted in my direct testimony, should not be considered a foregone conclusion), the difference between a Benchmark Resource and a third-party owned resource is that the Benchmark Resource is cost-based while the third-party owned resource is a fixed price. A utility may seek recovery of construction cost over-runs from utility customers (though the utility must demonstrate that the costs are prudent) but may not retain any construction cost under-runs as profit if the resource is under budget. Assuming a third-party owned resource is negotiated for a fixed price, the third-party proposal for a PPA may not seek recovery of construction cost over-runs; however, customers do not receive the benefit of construction cost under-runs.

Furthermore, construction cost over-runs associated with a Benchmark Resource may be specifically due to enhancements or modifications that result in improved resource availability or performance and overall reduction in costs to customers.

Q. Is it possible to have a truly fixed price contract?

A. I am advised by counsel that it depends on the negotiated terms and conditions, contract law and other applicable laws. For example, it is typical for contracts to have force majeure provisions. Depending on the given situation, claims of force majeure may result in an increased cost or risk to customers. Also, by way of example, bankruptcy laws may result in contracts being abrogated.

Q. Should the bid evaluation process be designed around past construction cost over- or under-runs for utility-owned projects?

A. No. In his testimony, Mr. Monsen points to what he claims to be a recent history of construction cost over-runs for power projects. Mr. Monsen then appears to formulate a conclusion that future utility project construction cost over-runs will occur and warrant generic bid adjustments aimed at increasing the evaluated costs of Benchmark Resources.[9] To support this conclusion, Mr. Monsen cites a 2007 Edison Foundation study prepared by The Brattle Group finding that utility infrastructure construction costs were on the rise at that time, in large part due to dramatic increases to prices of steel, cement, and other raw materials.

Q. Are the findings of the 2007 Edison Foundation study relevant to future construction cost over- and under-runs?

A. No. Mr. Monsen fails to note how many of the referenced projects were performed under a fixed price EPC contract. Mr. Monsen also fails to note that since this study was published, demand for electricity has fallen sharply and has continued to decline, impacting the relevance of the findings contained in the study. For example, one of the findings in the 2007 Edison Foundation study

[9] NIPPC/100, Monsen/7, 33.

cited by Mr. Monsen is that labor costs were increasing due to a backlog of contracts at large EPC firms.[10] However, since demand has fallen, there is no longer such a backlog or accompanying pressure on labor costs (overtime, premium pay, etc.), major equipment and other commodities. Since construction costs are comprised of labor and materials costs, falling labor and materials costs imply a reduction in overall construction costs. This only highlights the fact that past trends in construction costs are not necessarily reliable predictors of future construction costs. Further, under no circumstances should a *generic* bid adjustment be developed, to be applied to all future bid solicitations, based on past trends or anecdotal evidence of utility project construction cost over-runs. Rather, the bid evaluation process should be flexible enough to account for shifting trends in construction costs and the ability of the EPC market to submit fixed price bids.

Q. Does Mr. Monsen describe any other instances of construction cost over-runs?

A. Yes. Mr. Monsen describes two instances of utility construction cost over-runs: one with Southern California Edison Company (SCE)[11] and one with Otter Tail Power Company.[12] Mr. Monsen concludes that had appropriate bid adjustments been applied to the utility alternative, an IPP bid may have been selected instead

[10] NIPPC/100, Monsen/8.
[11] NIPPC/100, Monsen/10.
[12] NIPPC/100, Monsen/8.

and this would have saved customers from higher costs on the assumption that an IPP would have been obligated to absorb the construction cost over-runs.[13]

Q. Do you agree with this conclusion?

A. No, this is a gross over-simplification. As I noted in my direct testimony, in the face of uncertain or volatile prices for materials, IPP bidders become less willing to make fixed-price bids.[14] Further, in the event price volatility was not anticipated and an IPP experiences significant construction cost over-runs, there is nothing to prevent an IPP from abandoning a project if it becomes economic to do so. In the event the utility is required to step into the project or otherwise purchase replacement power,[15] costs to customers may increase even more than the construction cost-over-run the original developer would have experienced. In this way, the potential for unforeseen increases in construction costs as presented by NIPPC may increase the risk associated with an IPP bid. Also, if the IPP uses the utility's credit to support the contract and the IPP fails, it would seem unlikely that the IPP would bear the costs.[16]

Q. How might the generic bid adjustments proposed by NIPPC impact customers?

A. Under NIPPC's proposed generic bid adjustments, the selection of an IPP bid would guarantee that customers would always pay the construction cost over-run adjustment, but never benefit if construction cost under-runs materialized. This is

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[13] NIPPC/100, Monsen/11.
[14] PAC/100, Kusters/18-19.
[15] Note that in the case of SCE, market purchases of replacement power may not have been a feasible solution. SCE was directed to acquire summer peaking capacity for reliability purposes. If no such capacity were available in the market, they might have missed their reliability goal completely.
[16] The Company selected a geothermal resource in Utah in the 2003B renewable RFP where the bidder abandoned the project after it determined it could not construct the project at the cost it had submitted in the RFP.

because IPPs will rationally attempt to avoid absorbing construction cost over-runs. If one assumes that construction costs are always on average higher than initial cost estimates, then presumably IPPs would increase their bid prices in order to account for this trend or enter into fixed price EPC contracts. Further, if generic bid adjustments are applied only to a Benchmark Resource, as applicable, IPP bids could increase their bid prices by slightly less than the amount of the adjustment, and their bids would still be competitive, even if the Benchmark Resource was itself subject to a fixed price EPC contract. If an IPP project is selected, customers may ultimately bear a much higher cost than if a Benchmark Resource were selected because of the application of generic bid adjustments.

Q. Are there other errors or inaccuracies in Mr. Monsen's analysis?

A. Yes, Mr. Monsen reaches conclusions based on inaccurate facts or misinterpreted assumptions. I rebut each of these below. These errors further highlight why the attempt to develop a generic pre-determined quantitative adjustments to apply to future resource solicitations is not advisable.

Q. How does NIPPC witness Mr. Monsen describe changes in price for the Dunlap project?

A[redacted]

Q. Do you agree with this finding?

A. No. This conclusion is erroneous in three ways. First, Mr. Monsen misinterprets the documents presented to support his claim. Mr. Monsen presents two documents in support of his conclusion. One is a memorandum dated September 11, 2009 from the IE to Commission Staff that includes an analysis of the PacifiCorp benchmark bid in the 2009R RFP. This document is designated in this docket as NIPPC Confidential Exhibit 114. The second document is dated July 24, 2009 and is a filing with the Wyoming Public Service Commission regarding confidential cost information related to the CPCN application for the Dunlap project. This document is designated in this docket as NIPPC Confidential Exhibit 115. In Mr. Monsen's testimony, he notes that there was a price increase during the time of the bid solicitation to the time of the CPCN application. However, the CPCN application was filed July 24, 2009, while the cost for the Dunlap project cost was submitted and reviewed by the IE in the 2009R RFP in September 2009. The CPCN was filed first; therefore, the price actually *decreased* from the CPCN application to the solicitation bid.

Mr. Monsen's second error was to inappropriately compare the estimated costs submitted to the IE and the full costs included in the CPCN application as including all of the same cost categories. Appropriately, the cost submitted to the IE did not include allowance for funds used during construction (AFUDC) because the bid evaluation team adds the cost of AFUDC during the evaluation process. Indeed, the IE stated in its report, the same confidential report referenced by Mr. Monsen in his testimony, that [redacted]

[redacted] Mr. Monsen compared the cost estimate, without AFUDC, submitted to the IE, with a cost estimate included in the Company's Wyoming CPCN filing, which *includes* AFUDC. Correcting for this second error would result in a five percent cost decrease using Mr. Monsen's comparison logic.

Mr. Monsen's third error is to misinterpret the purpose of the CPCN application, which does not in this case represent the Company's Benchmark Resource cost estimate for RFP 2009R. The Company did not make a formal decision to construct Dunlap until *after* the IE determined in its RFP 2009R report that Dunlap was the most cost effective alternative. The variance between the Company's cost estimate in the RFP 2009R Benchmark Resource and the cost assumption at the point of decision was zero. Both cost estimates were for the same cost without AFUDC.

Q. Why would the Company file a CPCN application in Wyoming prior to its Benchmark Resource being selected from the final shortlist?

A. As noted, the CPCN application is conducted to demonstrate that there is a need for the resource. In testimony, the Company disclosed that it was making the Dunlap project available in RFP 2009R as a cost-based alternative to bids received from market participants for PPAs, build own transfer arrangements or the sale of existing assets. The Company also disclosed that, once bids are received and analyzed in RFP 2009R, the Company would make a determination as to whether the Dunlap project was in the Company's customers' best interest as compared to other alternatives. If so, the Company would move to construct the Dunlap project as soon as possible.

Q. Did Customers benefit from the actual construction costs for the Dunlap project?

A. Yes. Customers benefited from the actual construction cost because it was [redacted] percent below its estimate.[17]

Q. Mr. Monsen also concludes that [redacted] **Do you agree with the conclusion regarding the Lake Side project?**

A. No. In support of his conclusion, Mr. Monsen relies on testimony submitted by the Company in a CPCN application filed with the Public Service Commission of Utah. This document is designated in this docket as NIPPC Confidential Exhibit 118. Mr. Monsen also relies on an exhibit accompanying the direct testimony submitted by the Company in Docket No. UE 217, a general rate case. This document is designated in this docket as NIPPC Confidential Exhibit 119. The projected cost included in the Utah CPCN application was for a proposed 534 MW Lake Side project proposed by a bidder in RFP 2003A. The bidder's cost projection did not include a subsequent decision by the Company to upgrade the combustion turbines and control systems that resulted in the Lake Side project being rated 558 MW. The costs included in Docket No. UE 217 represented the costs associated with the larger project. The Lake Side project, as constructed, included a prudent turbine and control upgrade as well as other upgrades that

[17] Confidential Exhibit PAC/204

improved the overall operating performance of the resource as well as the expected reliability and availability of the plant.

Q. Did Customers benefit from the actual construction costs for the Lake Side project?

A. Yes. Customers benefited from the actual construction cost because it was [redacted] percent below its estimate.[18]

Q. Do you agree with Mr. Monsen's conclusion regarding the Seven Mile Hill project?

A. No. In support of this conclusion, Mr. Monsen relies on a Wyoming CPCN application for Seven Mile Hill dated August 31, 2007. This document is designated as NIPPC Confidential Exhibit 120. Mr. Monsen also relies on a Wyoming Section 109 Permit Application, made on June 15, 2009, for the Dunlap project. This document is designated as NIPPC Confidential Exhibit 121. Comparing cost references in these two documents is not an appropriate comparison. The cost reference included in the Dunlap permit application was for the *projects* constructed at Seven Mile Hill in 2008. The purpose of the cost statement in the Dunlap permitting application was to conservatively demonstrate that ad valorem taxes in Carbon County, Wyoming would increase as a result of the wind *projects* constructed in the county at the Seven Mile Hill site during 2008. Mr. Monsen's comparison is erroneous because he compares the estimated cost of one project with a tax-related cost reference for two wind projects.

[18] Confidential Exhibit PAC/204.

Q. Did Customers benefit from the actual construction costs for the Seven Mile Hill project?

A. Yes. Customers benefited from the actual construction cost because it was [redacted] percent below its estimate.[19]

Q. Do you agree with conclusions made by Mr. Monsen regarding the Goodnoe Hills project?

A. No. Mr. Monsen's analysis is flawed as discussed below, and, as a result, the conclusion that the actual cost of Goodnoe Hills was 29 percent higher than the estimated cost is not accurate.

Q. How is Mr. Monsen's analysis flawed?

A. In support of his conclusion, Mr. Monsen relies on two documents: 1) an excerpt from the direct testimony of the Company in a 2007 rate case before the Idaho Public Utilities Commission designated as NIPPC Exhibit 116; and 2) an excerpt from the direct testimony of the Company in a 2008 rate case before the Commission designated as NIPPC Exhibit 117. Mr. Monsen compares a cost reference of $151.9 million in the Idaho testimony and a cost reference of $196.6 million in the Oregon testimony. From this, Mr. Monsen erroneously concludes that the actual construction cost of Goodnoe Hills increased by 29 percent. However, comparing these numbers does not result in an accurate comparison because the cost referenced in the Idaho testimony excluded $44.7 million of accrued construction work in progress costs. The project was under construction at the time of the Idaho testimony and was subject to an EPC agreement that included milestone payments. Exhibit PAC/203, an exhibit included in the Idaho

[19] Confidential Exhibit PAC/204.

rate case reference by NIPPC, shows $196.6 million of total estimated costs for Goodnoe Hills. Therefore, a correct analysis would have concluded [redacted] construction cost over-run and [redacted] construction cost under-run.

Q. Did Customers benefit from the actual construction costs for the Goodnoe Hills project?

A. Yes. The Goodnoe Hills project was acquired from a third-party joint venture that primarily consisted of a NIPPC member. The third-party joint venture constructed the project under an EPC contract. Customers benefited from the actual construction cost because it was [redacted] below its estimate.[20]

Q. Mr. Monsen refers to 11 utility-owned projects located in California for support of its proposed seven percent bid adjustment. What is your overall assessment of this analysis?

A. This is not a robust analysis. First, because Mr. Monsen presents no comparable information about the history of construction cost over-runs (and associated impact on utility customers) for IPP projects, it is impossible to conclude from this data set that utility-owned projects pose more risks to customers resulting from construction cost over-runs. Second, a sample of eleven projects in one state over the last ten years should not be used to extrapolate future trends and apply those trends to future RFPs issued by an Oregon utility. Third, NIPPC does not perform any analysis or review of the underlying procurement methodology and EPC market that was then in place to design and construct the resources.

Q. Are there other problems with Mr. Monsen's analysis?

A. Yes. Mr. Monsen's example of SCE's project is inapt. Further review of the

[20] Confidential Exhibit PAC/204.

relevant California Public Utilities Commission (CPUC) proceeding reveals that this project was unique: it was a directive from the CPUC to SCE to develop and construct black-start reliability "must-run" resources in a very short time period. The reason that SCE's original estimates were low was because, as SCE noted in its testimony, it did not have adequate time to scope the project.[21] SCE did not have adequate time to scope the project because it was given less than a year to develop and install up to 250 MW of black-start, dispatchable generation capacity.[22] This unique circumstance involving a "fast track" project should not be used to extrapolate a trend that informs the evaluation process of future RFPs in Oregon.

Q. What has been the Company's experience with respect to construction cost-over-runs on utility-owned resources?

A. The Company's analysis shows that there has been an average cost under-run of [redacted] percent associated with the Company's owned wind projects. Confidential Exhibit PAC/204 shows the costs used for evaluation purposes and the actual costs for the Company's owned thermal and wind projects. The highest construction cost under-run was [redacted] percent whereas the highest construction cost over-run was [redacted] percent.

Q. What do you conclude from this?

A. A corrected analysis supports the following conclusions: 1) construction cost over-runs are a not a demonstrable past or current trend; 2) the Company has

[21] NIPPC/100, Monsen/10.
[22] NIPPC/102, Monsen/1-2 ("On August 15, 2006, in Rulemakings 05-12-013 and 06-02-013, an Assigned Commissioner's Ruling (ACR) "Addressing Electric Reliability Needs in Southern California For Summer 2007" directed Southern California Edison Company (SCE) to, among other thing, pursue the development and installation of up to 250 MW of black-start dispatchable generation capacity within its service territory for 2007 operation.")

estimated its utility Benchmark Resource costs in good faith; and 3) there is no need to impute a prescriptive construction cost over-run bid adjustment to Benchmark Resources.

Q. Mr. Monsen recommends that construction cost over-runs during the first five years of plant operations should be included in the calculation of the final construction cost over-run adjustment. Do you agree?

A. No. As an initial matter, this aspect of Mr. Monsen's testimony is beyond the scope of the current proceeding. As noted in the May 30, 2012 Administrative Law Judge (ALJ) Ruling, one of the issues the parties discussed was capital additions over the resource life.[23] This issue was not selected as part of Phase II, which is limited to the four items noted above and listed in Order No. 12-324. As such, this aspect of Mr. Monsen's testimony should not be considered. Mr. Monsen asserts that the fact that a utility could plan to upgrade a plant after commissioning but not include those costs in the evaluation of the project approval stage warrants a generic bid adjustment for construction cost over-runs related to deferred capital expenditures. This again illustrates my points regarding the conceptual framework for this docket. If there is a concern regarding the *potential* for utilities to exclude *planned* upgrades from the initial Benchmark Resource cost estimate, the focus should be on designing a bid evaluation process that reduces or eliminates this possibility.

Q. Does this conclude your testimony on construction cost over- and under-runs?

A. Yes.

[23] ALJ Ruling, p. 2 (Item 8 – Capital Additions Over the Resource Life).

<u>Heat Rate Degradation</u>

Q. Please summarize your testimony as it relates to heat rate degradation.

A. I first describe the framework through which heat rate degradation should be evaluated in this phase of the docket by applying the conceptual framework described in part one of my testimony. I then discuss in detail the flaws associated with NIPPC witness Mr. Monsen's analysis. I explain that his analysis supporting generic bid adjustments associated with heat rate degradation is deficient in a number of ways with respect to the relevance of the data set used and the logic of the analysis itself.

Q. Under your conceptual framework, what should be the focus of this effort on heat rate degradation?

A. The focus should be on ensuring that heats rates are forecasted as accurately as possible for all proposals, including a Benchmark Resource (if any), during the bid evaluation process. This is accomplished by the IE verifying that degradation values are consistent with those provided from the Original Equipment Manufacturer (OEM), which is the best source of this data. Again, the focus should be on reducing the *potential* for bias in the evaluation of the Benchmark Resource by ensuring that assumptions underlying the proposal are reasonable.

Q. What are the comparative risks associated with heat rate degradation for utility and third-party owned resources?

A. Assuming that the utility is able to negotiate a contractual financial heat rate

Q. What are the comparative risks associated with heat rate degradation for utility and third-party owned resources?

A. Assuming that the utility is able to negotiate a contractual financial heat rate guarantee in the contract with the third-party owned resource (which as noted in my direct testimony should not be considered a foregone conclusion), the difference between a Benchmark Resource and a third-party owned resource is that the energy from a utility resource is cost-of-fuel-based while the third-party owned resource is a fixed per-unit price. Exhibit PAC/205 provides an example of how a guaranteed heat rate compares on an economic basis to the heat rate curve from a Benchmark Resource where the Company has included a heat rate degradation curve. The exhibit illustrates that any benefit to customers of the guaranteed heat rate is highly dependent on what the guarantee is as it compares to the heat rate degradation curve. If the bid evaluation process includes the heat rate degradation curve from a Benchmark Resource and a heat rate guarantee from third-party bidders, then no adjustment is required because the evaluation process already takes this into account.

Q. Are these differences currently addressed in PacifiCorp's bid evaluation process?

A. Yes. As explained in detail in my direct testimony,[24] bids that are subject to degradation and part-load heat rate impacts are analyzed as such, using information provided by the OEM data. Bids that are not subject to such variation are modeled as having constant heat rates.

[24] PAC/100, Kusters/11-17.

Q. Should the bid evaluation process be designed around past or current trends of heat rate degradation in utility-owned projects?

A. No. In his testimony, Mr. Monsen points to a database of annual cost and operating characteristics of utility-owned generation for the years 1981 to 1999 to support a conclusion that certain trends in heat rate supports the use of generic bid adjustments.[25] As will be described more fully below, there are flaws in Mr. Monsen's analysis. Further, given heat rate variability and the number of factors that can ultimately influence heat rates over time, a *generic* bid adjustment would still not be appropriate to be applied to future bid solicitations, even if the analysis were robust. Rather, the bid evaluation process should be designed to be flexible enough to account for changing heat rates over time.

Q. Please describe the dataset Mr. Monsen uses to derive a heat rate adder.

A. The Wolfram dataset is a public dataset containing actual operating experience of generation plants across the United States over the period 1981-1999. The earliest commercial operation date (COD) in the dataset is 1915.

Q. Is this dataset useful to extrapolate future heat rate degradation trends?

A. No. Heat rate variation is caused most significantly by variation in operation. The variation seen in this dataset is likely due to a variety of factors including ambient conditions, plants operating at partial load, level of duct firing, starting and stopping, and actual heat rate degradation. The Company is not aware of any statistically defensible methodology to measure the amount of heat rate variation attributable to each contributing factor based solely on the data in this dataset.

[25] NIPPC/100, Monsen/25

Thus, it is inaccurate to say that all differences in heat rates result from or constitute heat rate degradation.

Q. Please describe the filters Mr. Monsen applies to the dataset.

A. Mr. Monsen excludes fuels other than natural gas. The first natural gas-fueled plant to appear in Mr. Monsen's analysis is the Lakeside, Wisconsin plant, with a COD of 1920. Because generation plants pre-dating 1999 are unlikely to be able to achieve heat rates below 7,000 Btu/kWh he also excludes low heat-rate plants as data errors.

Q. Are these filters appropriate?

A. Yes. However the low heat-rate exclusion highlights the second critical deficiency of Mr. Monsen's analysis. Mr. Monsen rightly notes that the technologies being constructed pre-1999 cannot produce sub-7,000 Btu/kWh performance that is expected from current natural gas-fired technology. In response to NIPPC Data Request 4.12, the Company provided a typical combined-cycle combustion turbine (CCCT) heat rate curve with an average "new and clean" maximum load heat rate of 6,657 Btu/kWh, and fully-degraded maximum-load heat rate of 6,771 Btu/kWh. Therefore *none* of the generation plants retained by Mr. Monsen for analysis are relevant for technologies that will be built in the future. Neither magnitude of heat rate degradation nor partial load performance could reasonably be inferred from the obsolete technologies represented in the Wolfram dataset.

Q. Please describe the calculation Mr. Monsen performs on the filtered dataset to derive what he describes as "heat rate degradation."

A. For a given plant, the best (lowest) heat rate is compared to all other heat rates available. The average deviation from the best heat rate is called "heat rate degradation." The overall adder is a capacity-weighted average of the "degradation" of each plant.

Q. Is this approach reasonable?

A. Absolutely not. Mr. Monsen makes no attempt to separate the effects of partial load operation from heat rate degradation, so what the Wolfram dataset reports as degradation is really the conflation of the two effects. Additionally, selecting the lowest heat rate as a proxy for new and clean heat rate is problematic: In the example Mr. Monsen highlights, the AB Hopkins plant runs during the years 1984-1985 and 1996-1999. In the interim, the plant capacity changes, and this could suggest upgrades. As it happens, the lowest heat rate occurs in the second period, in 1997. Mr. Monsen then calculates a "degradation" value versus all other years, including 1984 and 1985. Intuitively, one would have expected the lowest heat rate to come from one of the earliest years, and the fact that it doesn't again suggests the plant may have been upgraded in the 11 years for which data is not available or that there was a material change in how the plant was operated.

Q. What is the result of Mr. Monsen's calculation?

A. Mr. Monsen determines that the average deviation from lowest heat rate is eight percent.

Q. What insights can reasonably be taken from this eight percent number?

A. It is not possible to draw any reasonable conclusions from the eight percent number. For the reasons set forth above, the figure has no meaning whatsoever in the context of heat rate degradation.

Q. Do you agree with Mr. Monsen's proposed heat rate bid adjustment?

A. No. Mr. Monsen derived observed differences from what are assumed to be full-load heat rates that are, in reality, influenced by part-load operation, start-ups and shut-downs, duct firing, 1x1 operation, etc. These activities are necessary to maintain system reliability and can result from carrying operating reserves, integrating variable wind generation, and following net system load. Any variation between actual heat rates and full load heat rates can result from a resource providing these types of essential reliability services, and any incremental "cost" of these activities are *at least* offset by the value of the flexibility provided.

Q. Does this conclude your testimony on heat rate degradation?

A. Yes.

Wind Capacity Factor

Q. Please summarize your testimony with respect to wind capacity factors?

A. As with heat rate degradation and construction cost over- and under-runs, I first describe the framework through which wind capacity factors should be evaluated in Phase II. I again conclude that the focus should be on ensuring that wind capacity factors are forecasted consistently for *all* alternatives during the final shortlist stage of the bid evaluation process.

Q. Is a capacity factor adjustment necessary to improve the current process when a Benchmark Resource is part of an RFP?

A. No. Such an adjustment is not necessary because the Company already uses a third-party technical expert (the Capacity Factor Expert) to assess the capacity factor estimates associated with *all* alternatives on the final short list. The Capacity Factor Expert makes adjustments to *each* alternative on a non-discriminatory basis.

Q. Does NIPPC's proposal to implement a capacity factor adjustment for all utility-owned wind alternatives reduce the potential for bias during an RFP process?

A. No. In fact, just the opposite is true. NIPPC's recommendation introduces a bias that distorts the economic evaluation of a Benchmark Resource and potentially increases costs for customers.

Q. Please explain.

A. NIPPC argues that a wind capacity factor adjustment for all utility-owned alternatives is necessary to remove an alleged bias. NIPPC argues for an asymmetrical capacity factor reduction that would only apply to utility-owned alternatives. Accepting NIPPC's recommendation introduces an arbitrary bias into the RFP process rather than removing the *potential* for bias. NIPPC's recommendation is nonsensical and contrary to the purpose of this docket because it would result in an unwarranted and artificial inflation of the analyzed value associated with PPA bids as compared to a Benchmark Resource (if present). The use of a Capacity Factor Expert by the Company renders NIPPC's recommendation moot. A bid adjustment in any form is simply not necessary to fairly evaluate the estimated capacity factor of a wind resource during the Company's future RFP processes. There is no standard process in the wind industry for estimating wind capacity factors. Regardless of ownership, the Company relies on the Capacity Factor Expert to review and provide an unbiased capacity factor estimate for *each* alternative on the final shortlist. This benefits customers because the Capacity Factor Expert provides a non-biased adjustment to each capacity factor estimate, regardless of ownership status, resulting in a fair analysis during the RFP process without the *potential* for bias.

Q. Will the use of a Capacity Factor Expert inform the final resource decisions made by the Company in future RFPs that include a Benchmark Resource?

A. Yes. The wind capacity factor adjustments made by the Capacity Factor Expert to *all* alternatives on the final shortlist is then utilized by the Company to perform analyses to determine the resource selected.

Q. What should be the basis for making improvements in future RFPs?

A. As it relates to estimating wind capacity factors, the Company considers its current use of a Capacity Factor Expert to be a best practice based on information known at this time.

Q. What other benefit does a Capacity Factor Expert provide?

A. As mentioned above, there is not an industry standard methodology for estimating wind capacity factors. A Capacity Factor Expert brings consistency to the process. In addition, the technology of forecasting capacity factors for wind resources will continue to evolve. Using a Capacity Factor Expert will assure that the most up-to-date information is incorporated into future RFP processes. Wind capacity factor forecasts are based on properties specific to the resource (location, turbine type, etc.), and are unrelated to whether the bid is a third-party proposal or a Benchmark Resource. A Capacity Factor Expert can incorporate resource specific considerations into the review.

Q. Mr. Monsen proposes a capacity factor adjustment that would apply to all future utility-owned bids. Is Mr. Monsen's analysis based on a correct comparison?

A. No. Aside from the basic flaw that Mr. Monsen's proposal introduces an asymmetrical bias into the RFP process, Mr. Monsen's analysis is also flawed because it is based on a methodology that compares his observations of past performance to capacity factors *originally anticipated for the plants.*

Q. Is Mr. Monsen's wind capacity factor comparison methodology consistent with the Commission's policy?

A. No. Mr. Monsen's comparison methodology is inconsistent with Commission policy because it does not compare observation of performance against the capacity factor utilized *at the time of decision.* The Commission stated in UE 200 that the capacity factor at the time of the decision is the key metric. The Commission stated as follows: "[a]lthough the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes."[26] Because of this fundamental flaw, NIPPC has utilized incorrect data in its analysis.

Q. How else is NIPPC's wind capacity factor analysis flawed?

A. NIPPC's analysis is flawed because it fails to take into consideration that an inadequate history exists for the Company's wind fleet to reach broad and precedent-setting conclusions of policy.

Q. What wind project does the Company own that has the longest history?

A. Foote Creek I has been in service the longest. As Confidential Exhibit PAC/206 shows, the actual Foote Creek I capacity factor [redacted]

Q. At the time of decision, what is the capacity factor estimate based on?

A. When the Company makes a decision to acquire a weather-dependent variable energy resource, the decision is based on the estimated long-term annual capacity factor as represented through third-party technical experts on an annual 50 percent probability (P50) basis; meaning there is a reasonable expectation that the actual calendar year production will be equally likely to be higher or lower during any given calendar year.

Q. How does the Company's use of a Capacity Factor Expert in the RFP process compare to NIPPC's comparison analysis?

A. As described above, the current RFP process used by the Company utilizes a Capacity Factor Expert to provide an unbiased review of the P50 estimate provided by all bidders and a Benchmark Resource (if any) on the final shortlist.

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[26] *In the Matter PacifiCorp, dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202*, Docket UE 200, Order No. 08-548 at 21 (November 14, 2008).

This practice compares the P50 estimate for third-party bids and the Benchmark Resource (if any) on a consistent basis. NIPPC's analysis did not perform any comparison of actual PPA performance to the P50 assumption used by the owner of a PPA resource at the time of their decision.

Q. Has the Company compared the observed performance of PPA contracts in its portfolio against the P50 estimate used by the owner of a PPA resource at the time of their decision?

A. No. Historically, third-party owners have not provided the necessary information to the Company to complete such a comparison. Specifically, the owners of the PPA wind resources have not provided demonstrable evidence of the capacity factor they relied on in making their decision. Notwithstanding that some third-party owners provided a capacity factor estimate during the acquisition process, the Company has no clear evidence that the capacity factor estimate provided was indeed the capacity factor relied on by the asset owner when making their decision. It is for this reason the Company now requires RFP bidders to provide documentation of the source of their capacity factor analysis at the time the proposals are submitted. The Company then provides that analysis to the Capacity Factor Expert to ensure a consistent comparison for all bids on the final shortlist (including PPA bids and a Benchmark Resource, if any).

Q. How else is NIPPC's capacity factor analysis misleading?

A. As Confidential Exhibit PAC/206 demonstrates, the Company's wind assets do not have a long history of operations. NIPPC's analysis is misleading because it focuses heavily on capacity weighted averages and fails to take into account that the majority of actual generation data obtained to date occurred during two non-normal wind years (2009 and 2010).

Q. Why were 2009 and 2010 not normal wind years?

A. Certain parts of the United States experienced winds for the 12-month period ending March 31, 2010 that were far below average. AWS Truepower, a global leader in wind energy forecasting services, issued a press release on June 9, 2010[27] that stated:

> This past quarter had a noticeable impact on the wind climate for the 12 months ending 31 March, 2010, (Q1 2010). The northern plains, northern Rockies, and entire Midwest experienced below-normal winds, while much of the southeastern United States was above average. This one-year period is sharply different than the previous year (ending 31 March, 2009; Q1 2009), when over 80 percent of the United States experienced above average-wind speeds.

This low wind phenomenon widely affected wind capacity factors in 2009 and 2010, especially given the fact that the winter months typically account for the greatest share of the Company's annual wind energy production. The Foote Creek I chart in Confidential Exhibit PAC/206 demonstrates this phenomenon due to the greater number of years in which data is available.

Q. Does the Company have data associated with the use of a wind Capacity Factor Expert during a RFP process?

A. Yes. The data shows that the capacity factor estimates for bidder proposals are subject to adjustment to a greater extent than the Company's Benchmark Resource. Indeed, as Confidential Exhibit PAC/207 shows, the average

[27] AWS Truepower press release June 9, 2010. Wind speed anomaly for Q1 2009 through Q2 2010. http://www.awstruepower.com/wp-content/media/2010/06/AWST-windTrends-Bulletin_Q1-2010_Final.pdf

adjustment made by the Capacity Factor Expert to bidder estimates was [redacted] compared to the [redacted] adjustment the Capacity Factor Expert made to the Company's estimate. This demonstrates that Mr. Monsen's recommendation is moot because the Capacity Factor Expert can reasonably be expected to adjust all alternatives, regardless of ownership.

Q. Does this conclude your testimony with respect to heat rate degradation?

A. Yes.

<u>**Counterparty Risk**</u>

Q. Please summarize your testimony regarding counterparty risk.

A. I reiterate and further clarify the recommendation made in my direct testimony that a third-party bidder's credit evaluation should be conducted at the initial shortlist phase of the RFP, and again evaluated as part of the final shortlist along with the probability of default, if any, due to the lapse in time to conduct an RFP in addition to the non-negotiable terms and conditions in the underlying agreements. I also explain briefly how NIPPC witness Ms. Collins' testimony does not include information or analysis that is useful or necessary for answering the question at hand namely, how counterparty risk should be evaluated during the bid solicitation process.

Q. What was the recommendation you made in your direct testimony with respect to counterparty risk?

A. I recommended that the Commission approve template agreements with non-negotiable terms.

Q. Please provide an example of the types of terms and conditions you would recommend be non-negotiable.

A. Examples of the non-negotiable terms include security, credit support, default and remedies, compliance and audit requirements, standard operation requirements and third-party sales and purchase obligations. Exhibit PAC/208 is a template PPA where potential non-negotiable terms are highlighted.

Q. Is your recommendation that the probability of default be assessed as part of the bid evaluation process consistent with the conceptual framework applied to the other three factors?

A. Yes. The quantification of credit and probability of default would be calculated and applied on an RFP-specific and *resource-specific* basis. For all of the reasons I have described, the Company is not proposing a generic counterparty risk bid adjustment to be applied to *all* third-party bidders. Rather, the evaluation process is and should be designed to fairly and reasonably assess the risks associated with the specific bid and counterparty.

Q. Looked at in this light, what is the fundamental issue with Ms. Collins' testimony.

A. Though she is not explicit, Ms. Collins' testimony seems to be aimed at drawing general conclusions regarding the financial performance risk associated with IPPs. However, the fundamental problem with this approach is similar to the fundamental issues pointed out with respect to Mr. Monsen's testimony: that empirical evidence regarding past performance may be informative and useful for guiding process improvement but should not be used to reach generalized conclusions regarding future performance of all IPPs. The energy industry is dynamic, and not all IPPs are created equal. As such, the focus should be ensuring that each bidder is fairly and equitably evaluated.

Q. NIPPC witness Ms. Collins states that during the years 1992 through 1997, she only could recall one pre-operational bankruptcy.[28] What relevant conclusions, if any, can be drawn from this?

A. None. Since the 1990s, significant shifts have occurred in the energy industry that renders Ms. Collins' observations irrelevant to a valid assessment of current counterparty risk. Since the 1990s, the Federal Energy Regulatory Commission (FERC) began regulating the wholesale electric power markets, which significantly changed the landscape of those markets. Further, highly significant events have occurred that include the rise and fall of Enron, the collapse of the California electricity markets, and the bankruptcies of Calpine, Mirant and Edison Mission Energy, to name a few. These events so changed the wholesale energy markets that any observations concerning them made in the 1990s are irrelevant to an analysis of their state in the 2010s. This is even more the case with respect to Ms. Collins' observations on generator bankruptcies pre-1995, prior to FERC Order No. 888, which mandated the functional separation of utilities companies into merchant and transmission functions.

Q. Do you agree that the creditworthiness of a special purpose entity (SPE) depends on the terms of the PPA?

A. Yes, the PPA and the associated creditworthiness of the utility buyer would be one of the key determinants of an SPE's creditworthiness. Indeed, this creates a

[28] NIPPC/200, Collins/2

bias for the SPE to seek to transfer risk to the utility's customers through the PPA so that it can attain creditworthiness to attract financing and reduce earnings risk to its shareholders. It is the responsibility of a prudent utility to require appropriate credit support in the PPA to mitigate customer exposure related to credit risk posed by an SPE. This is particularly important in the case of an SPE where the third-party owner/developer is a non-creditworthy entity.

Q. Ms. Collins states that it would be incorrect to say that access to capital, which will always be more limited than a regulated utility's, is the cause of a project's inability to correct a management, operations, or fuel supply problem.[29] Do you agree?

A. I agree that access to capital is only one of several ways individual projects can fail.

Q. Ms. Collins states that she monitored and participated in bankruptcy cases "to curb adverse changes to a PPA by a bankruptcy judge, and in no case did that actually occur."[30] Is this even possible?

A. No. A bankrupt company can either assume as-is, assume as-is and assign, or reject a contract. I have been advised by counsel that there is no process by which a bankruptcy judge may make changes to a contract as a condition to the debtor assuming it.

Q. Ms. Collins defines "credit" as "loan or loans the IPE or SPE obtains to fund its business."[31] Do you agree with this definition?

A. No. Credit includes not only amounts advanced, but also the capacity to obtain

[29] NIPPC/200, Collins/5.
[30] NIPPC/200, Collins/3
[31] *Id.*

advances. Credit also includes the amount of security permitted by counterparties *not to be delivered* to secure out-of-market positions. Credit as "amount borrowed" is a shallow and incomplete definition; under Ms. Collins' definition, the more one owes on one's credit cards, the more credit one has.

Q. Ms. Collins defines "creditworthiness" as "the initial issuance of credit extended by a lender, and its terms and conditions. If the business gets a loan, it is said to be credit worthy; the loan is the evidence of that worthiness."[32] Do you agree with this definition?

A. No. Perhaps the initial making of a loan by a financial institution indicates that the financial institution believes that the borrower is creditworthy, but that is not always the case; the lender may be an affiliate or an equity investor. Many other factors must be analyzed to determine whether an entity is creditworthy. Additionally, different lenders have different standards. Large companies may borrow from major financial institutions without providing any security. For example, if an individual were lent money by a pawnbroker on the pledged security of her grandfather's pocket watch, that individual will not be able to prove his or her creditworthiness on the basis of that loan. As we saw in 2008, all subprime home borrowers did not become creditworthy simply because they had been able to obtain a home mortgage.

Q. Do you agree with Ms. Collins' statement that creditors "can and do" "take over operating IPP's [sic] and keep them operating"?[33]

A. No, it would be more accurate to say that creditors structure their documents so

[32] *Id.*
[33] NIPPC/200, Collins/6.

that they can take over operating but will only do so as an absolute last resort. This is an important distinction. Ms. Collins' testimony creates the incorrect impression that solvent lenders are standing ready to move in and protect their collateral and perform the PPA. In reality, the lenders generally do all they can to avoid and delay taking over non-performing assets, and generally seek from off-takers limitations of liability were they to do so, exposing off-takers to at the very least sustained periods of non-performance during a loan default.

Q. Ms. Collins posits a scenario where "a bidder with an investment grade rating could win, transfer the asset to an SPE and hold the asset at the lowest possible grade, beating another bidder that sat in between highest and lowest grades."[34] Is this possible?

A. Not in a PPA entered into by the Company. All of the Company's PPAs have assignment clauses that protect the Company from this risk.

Q. Ms. Collins characterizes being concerned with IPP credit as "hostile." Do you agree?

A. No. I would characterize it as a rational protection for the best interests of customers.

Q. Does this conclude your reply testimony?

A. Yes, it does.

[34] NIPPC/200, Collins/9.

Docket No. UM-1182
Exhibit PAC/201
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

PacifiCorp

Request for Proposals

Renewable Electric Resources

(RFP 2009R)

ISSUED: July 8, 2009

DUE DATE: September 10, 2009

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SECTION 1. INTRODUCTION

The purpose of this document is to prescribe the process by which PacifiCorp (the Company) will request and evaluate proposals from Bidders to fulfill a portion of the Renewable Resource generation identified in the Company's 2008 Integrated Resource Plan (IRP) as filed with and pending acknowledgement before the Oregon Commission. Action 1 of PacifiCorp's 2007 and 2008 IRP identifies 2,000 MW of cost effective renewable resources to be acquired by 2013, including 1,400 MW of renewable resources outlined in PacifiCorp's Renewable Energy Action Plan. Under this plan, the Company seeks to acquire 1,400 MW of new renewable resources by 2010, with an additional 600 MW in place by 2013.

This Renewable Request for Proposal (2009R RFP) will request renewable resources limited in size to no more than 300 MW[1] that are compliant with existing or anticipated renewable portfolio standards and that are new to the Company's resource portfolio. In addition, each renewable resource must have an expected annual output of at least 25,000 megawatt hours after accounting for planned and unplanned outages. The 2009R RFP will require renewable resources located within the Western Electricity Coordinating Council and capable of delivering energy, within the prescribed timeframe, in or into the Company's Network Transmission system[2] (www.oasis.pacificorp.com).

In addition to bidding in renewable resources, Bidders will have the option to bid in renewable resources coupled with energy storage. Energy storage has the distinct advantage of potentially enabling higher penetrations of intermittent renewable energy in the Company's portfolio. Pumped water, compressed air, battery storage, or other contractual forms can firm intermittent renewable resources and therefore create an energy resource that can be scheduled to better match customer demand or result in a higher degree of dependability throughout a prescribed time period. If the same resource is bid in the 2008R-1 RFP and the 2009R RFP, each bid will be considered under the terms of the RFP under which the bid is submitted. Qualifying facilities with a name plate of 10 megawatts or greater may participate as a qualified bidder.

The 2009R RFP will allow the Company to react effectively and competitively, and stay current with the competitive nature of the renewable energy resource construction and equipment market. The 2009R is for Renewable Resources which can reach commercial operation during the 2010 through 2012 time period. The purpose of this RFP is to comply with current regulatory rules, orders, and any applicable resource procurement state laws. This RFP may be used to comply with any specific state Renewable Portfolio Standard requirement.

This introductory Section 1 describes the type, timing and amount of resources sought. Section 2 addresses the procedural items. Section 3 covers logistics such as where and when proposals must be submitted, bid fees, success fees and minimum requirements, as well as important conditions and procedures. Section 4 outlines the required content and

[1] 300 MW is the nameplate capacity or quantity of capacity and is the upper limit permitted by Utah Senate Bill 202.
[2] Company's Eastern Control Area (PACE) and/or the Company's Western Control Area (PACW).

format. Section 5 outlines resource information including price and non-price information, integration, interconnection and transmission services. Section 6 outlines the bid evaluation and selection process. Section 7 outlines the awarding of contracts. All of the required Appendices which are required are included.

As discussed above, the 2008 IRP[3] identifies up to 2,000 megawatts of renewable resources by 2013. Under the 2007 IRP plan, the company will seek to acquire up to 1,400 megawatts of new cost effective renewable resources by 2010, with an additional 600 megawatts in its portfolio by 2013. The 2,000 megawatts of renewable resources is inclusive of the 1,400 megawatts of cost-effective renewable resources identified in the company's 2004 IRP.

The potential acquisition quantity for this 2009R RFP will be up to 500 MW

CHART 1- RESOURCE POTENTIAL QUANTITY

Commercial Operation Date	Potential Quantity
2010	Up to 200 MW
2011	Up to 100 MW
2012	Up to 200 MW

Renewable Resources are defined as:

An electric generation facility or generation capability or upgrade that becomes operational on or after January 1, 1995 that derives its energy from one or more of the following:

(A) wind energy;
(B) solar photovoltaic and solar thermal energy (i.e., concentrated solar);
(C) wave, tidal and ocean thermal energy;
(D) except for combustion of wood that has been treated with chemical preservatives such as creosote, pentachlorophenol or chromated copper arsenate, biomass and biomass byproducts, including
  (I) organic human or animal waste;
  (II) spent pulping liquor;
  (III) forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce wildfire risk;
  (IV) agricultural residues;
  (V) dedicated energy crops; and
  (VI) landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters or municipal solid waste;
(E) geothermal energy;

[3] More information on the IRP can be found at www.pacificorp.com/Navigation/Navigation23807.

(F) certified low-impact hydro-electric energy with a nameplate capacity less than fifty megawatts, without regard to the date upon which the facility becomes operational, if the facility is certified as a low-impact hydroelectric facility on or after January 1, 1995, by a national certification organization;
(G) waste gas and waste heat capture or recovery;*
(H) efficiency upgrades to a hydroelectric facility, without regard to the date upon which the facility became operational, if the upgrades become operational on or after January 1, 1995;
(I) geothermal energy if located within the state of Utah, without regard to the date upon which the facility becomes operational; or
(J) hydroelectric energy if located within the state of Utah, without regard to the date upon which the facility becomes operational.

Bidders have the option to also bid Renewable Resources coupled with energy storage.

The Company may opt to contract for more or less renewable resources, depending among other things, bids received in response to the ongoing 2008R-1 RFP, quality of bids received in response to this RFP, updates to the Company's forecasts, regional transmission availability and timing, and changes in the power supply market conditions.

The Renewable Resource must have a commercial operation date no later than December 31, 2012. Bidders may only bid in Renewable Resources in the form of a Power Purchase Agreement (PPA), an Asset Acquisition and Sale Agreement or a Build Own Transfer (BOT).[4] To the extent that Bidders bid in variations of an asset acquisition of an existing project, a PPA or BOT, such proposals will be considered at the Company's discretion and the Company reserves the right to reject non-compliant bids[5]. PacifiCorp generation will submit a benchmark resource(s) which are further described in **Appendix I.**

The Company benchmark will be received by the Independent Evaluator (IE) no later than one week prior to the receipt of market bids. The market bids will not be opened until such time as the Company benchmark is reviewed and validated by the IE.

In order to provide for a transparent and fair process, the RFP will be conducted under the oversight of IE. An IE has been retained by the Company on behalf of the Oregon Public Utility Commission, which will be involved in ensuring the RFP is conducted in a fair and reasonable manner.[6] Potential Bidders are invited and encouraged to contact the Oregon IE with questions or concerns. More information concerning the role of the IE is provided in **Appendix K**.

* PacifiCorp reserves the right to reject waste gas and waste heat capture or recovery resources if the resource is not eligible for existing or anticipated renewable portfolio standard compliance.

[4] Form of Power Purchase Agreement is set forth in Appendix E and the Build Own Transfer, and Asset Acquisition and Sale Agreement is set forth in Appendix F.

[5] If bids are rejected on the basis of non compliance the bid fee will be returned to the bidder.

[6] A Bidder may request the appointment of an independent third-party to assist the Washington Utilities & Transportation staff with review of any utility bids at the expense of the Bidder requesting the appointment.

Contact information for the IE is as follows:

Oregon Independent Evaluators: Boston Pacific Company, Inc.	
Craig Roach: croach@bostonpacific.com Frank Mossburg: fmossburg@bostonpacific.com	

The Company has the option of seeking regulatory acknowledgement of the Final Shortlist consistent with Oregon Order No. 06-446. PacifiCorp will seek rate recovery consistent with standard rate making practices in its six state jurisdictions.

SECTION 2. PROCEDURAL ITEMS

PacifiCorp is seeking proposals for renewable projects, existing and or new construction, with a projected online date prior to December 31, 2012. PacifiCorp is seeking proposals for up to the potential quantities set forth in Section 1 of this solicitation. PacifiCorp will evaluate the proposals based on cost effective economics, a viable implementation schedule, verifiable major equipment availability (such as wind turbines or other long lead-time equipment), appropriate ability to provide security for the Bidders proposed obligation, transmission access and interconnection status, and conformance to the *pro forma* contracts attached as Appendices to this RFP. PacifiCorp may elect to select more or less than the resource potential quantity, or no proposals at all as a result of this solicitation.

Each proposal will be prepared at the sole cost and expense of the Bidder and with the express understanding that there will be no claims whatsoever for reimbursement from PacifiCorp. PacifiCorp is not liable for any costs incurred by Bidders in responding to this RFP or for any damages arising out of or relating to PacifiCorp's rejection of any proposal, or Bidder's reliance upon any communication received from PacifiCorp, for any reason. Bidder shall bear all costs and expenses of any response to PacifiCorp in connection with its proposal, including providing additional information and Bidder's own expenses in negotiating and reviewing any documentation.

To the extent that the proposals are deemed conforming all proposals belong to PacifiCorp and will not be returned. PacifiCorp will use reasonable efforts to protect information clearly and prominently marked as proprietary and confidential on the page it appears, but PacifiCorp reserves the right to release such information to agents or contractors to help evaluate the Proposal, as well as to its regulators and non-bidding parties to regulatory proceedings subject to standard protective orders or confidentiality arrangements. PacifiCorp shall not be liable for any damages resulting from any disclosure of such information, howsoever occurring.

PacifiCorp is interested in creative proposal options that add value to customers. As a result, PacifiCorp encourages Bidders to offer several different alternatives under the same proposal. For each proposal, Bidders must submit a Bid Fee of $10,000 which allows a Bidder to submit a base proposal and up to two alternatives for the same bid fee. Bidders will also be allowed to offer up to three additional alternatives at a fee of $1,000 each. Alternatives will be limited to different bid sizes, contract terms, in service dates, and/or pricing structures. A Bidder may submit more than one proposal. If a Bidder submits the same proposal but with three different bid sizes, the proposal will be considered one proposal with two alternatives and the Bidder will receive three separate bid numbers for the proposal and pay one bid fee. The Company's objective in offering Bidders the opportunity to propose multiple alternatives is to allow the Company to optimize the benefits from the solicitation by combining proposals of different sizes, terms and in-service dates. Proposals must be submitted in the legal name of the respondent who would be bound by any agreement with PacifiCorp. A Success Fee will be charged to successful bid(s). The Success Fee will be assessed after the final amount of Bid Fees and the IE and Consultant costs are known, provided that in no event shall the Success Fee exceed $300,000 dollars per successful bid.

SECTION 3. LOGISTICS

A. SCHEDULE

Chart 2 sets forth the anticipated schedule.

CHART 2 – ANTICIPATED SCHEDULE

Event	Estimated Timeline
Selection of Independent Evaluator	May 19, 2009
File Draft 2009R RFP for approval in Oregon	June 5, 2009
2009R Issued	July 8, 2009
2009R Bid Conference	July 17,2009
Intent to Bid Forms and Appendix due	August 3, 2009
Benchmark Resource(s) Responses due	September 3, 2009
Responses due	September 10, 2009
Evaluation completed	October 12, 2009
Oregon Commission acknowledgement of Final Shortlist	November 2009
Bidder negotiations completed	November 2009

Bidders should note that the above schedule is an anticipated schedule only and is subject to change. The Company accepts no liability to the extent the actual schedule is different from the anticipated schedule.

B. 2009R BID RFP CONFERENCE

Time: 9:30 PPT
Date: July 17, 2009
Location: Oregon - 825 NE Multnomah – Room TBA

Interested parties and Bidders may submit questions prior to the RFP bid conference, so that such questions may be addressed in a more timely fashion. All information, including the pre-bid conference materials, questions and answers will be posted on the PacifiCorp website at www.pacificorp.com. The Company will be responsible to maintain and post all materials on the Company's website at www.pacificorp.com. Any questions on the RFP or related documents should be sent to the Company via email at RFP2009R@pacificorp.com.

Communications with the Oregon IE can be emailed to them directly at the following email addresses:
Oregon IE: croach@bostonpacific.com or fmossburg@bostonpacific.com

C. INTENT TO BID FORMS

Bidders who intend to be considered as part of this RFP process must return both the "Intent to Bid Form" and the "Bidder's Credit Information" (**Appendices A and D**) as set forth below.

Five (5) copies of the Intent to Bid Form and the Bidder's Credit Information must be sent to the following address by express, certified or registered mail, or hand delivery by 5:00 p.m. Pacific Prevailing Time on September 10, 2009

Oregon Independent Evaluator
Boston Pacific Company, Inc.
c/o PacifiCorp
Attention: RFP 2009R
825 NE Multnomah, Suite 600
Portland, Oregon 97232

D. SUBMISSION OF BIDS

The Bidder will be required to submit its proposal(s) to the following addresses. Bidders must submit the following to the address below:

1. a signed original and five (5) hard copies of each bid and any required forms, and
2. two (2) electronic copies of the bid and any required forms (on two (2) separate compact discs) that are in PDF format.
3. one (1) electronic copy of the Pricing Input Sheet.
4. one (1) electronic and hard copy of the wind report supporting the one years worth of wind data.
5. one (1) electronic copy of one year worth of wind data to support the capacity factor.

All submitted bids must be transmitted by express, certified or registered mail, or hand delivery to the following address:

Oregon Independent Evaluator
Attention: RFP 2009R
825 NE Multnomah, Suite 600
Portland, Oregon 97232

Bids will be accepted until 5:00 p.m. Pacific Prevailing Time on September 10, 2009. **Any bids received after this time will be subject to return unopened to the Bidder following a decision based on consultation between the IE and PacifiCorp.**

PacifiCorp will not accept any late proposals. The anticipated dates for evaluations, negotiations and definitive agreements are estimates, and actual dates will vary for reasons that include, but are not limited to, negotiation time, availability of key personnel, due diligence, the evaluation or negotiation of any issues unique to any bid, Bidder, or project, Bidder's willingness to agree to forms of agreements desired by PacifiCorp, PacifiCorp's evaluation of Bidder's creditworthiness, and actions required by any third parties.

E. RFP TEAM

An RFP Team will be established by the Company prior to the final approval of the RFP. The RFP Team shall consist of an Evaluation Team and Intent to Bid Team. The composition of the teams and their primary roles and responsibilities are shown below in Chart 3.

CHART 3

Work Group	Roles
IE	The IE will ensure a fair and reasonable process is used in the RFP and will validate the Company is following the bidder pre-approval process and monitor and document all material aspects of the solicitation, evaluation and negotiation processes. See **Appendix K** for the Roles of the Oregon IE.
Evaluation Team: Origination and/or Third-Party consultants as required	Overall coordinator of the process. Bid process management for all proposals and coordination with the IE and all of the work groups. Evaluation of the non-price components of the analysis. Specifying, evaluating and confirming conformity with design specifications; conducting, as needed, technological and operational due diligence, environmental due diligence on all resources.
Evaluation Team: Structuring and Pricing and/or Third-Party consultants as required	Economic analysis and modeling including validation of the inputs to the risk assessment of the bid and the benchmark bids.

Evaluation Team: Environmental	If applicable, review of local, state, and federal permits, permit applications, and supporting documentation, including: wildlife baseline study (including wildlife habitat mapping, special status species survey, and raptor nest survey); avian and bat use data analysis (including four-season study); avian and bat impact assessments; rare plant habitat assessments; wetlands survey; historic, cultural, and archaeological resources survey; Phase One environmental site assessment; and project mitigation and monitoring plan (including any proposed conservation easements).
Evaluation Team: Credit	Evaluate credit requirements for Final Shortlist bidders
Evaluation Team: Legal	Legal will confirm compliance of bids to requirements of RFP and its Forms, Attachments and Appendices; conduct of legal process; conducting due diligence inquiries; supervising any documentation entered into as part of the RFP process.
Intent to Bid Team: Origination, Legal and Credit	Origination, Legal and Credit will work with the IEs to ensure that Appendices A and D are complete.

F. BID FEES

To help defray the cost of the Oregon Independent Evaluator each Bidder shall submit with each of its bid proposals a nonrefundable "bid fee" of $10,000. A bid may consist of one base proposal in addition to two alternatives for the same bid fee. The alternatives may consist of a different bid size, contract term, in-service date and/or pricing structure for the same bid. In addition, Bidders will have the option of submitting up to three additional alternatives for a fee of $1,000 per alternative. The bid fee(s) must be submitted with the proposals to Boston Pacific Company, Inc. The Bidder must attach to its proposal a certified check written in the required amount payable to the order of PacifiCorp. Bidders may submit multiple base bid proposals in response to this RFP. The Oregon IE, in consultation with the Company shall confirm whether a Bidder's submission constitutes one or more proposals, for purposes of assessing bid fees. The cost of the IE not recovered by the Bid Fees shall be covered by a fee(s) assessed upon the successful bid(s) (the "Success Fee"). The Success Fee will be determined once the final amount of Bid Fees and IE and Consultant cost are known, provided that in no event shall the Success Fee exceed $300,000 per successful bid. Any questions regarding bid fees should be directed to Boston Pacific Company, Inc.

G. MINIMUM ELIGIBILTY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements are not met. To the extent proposals do not comply with these requirements they will be deemed ineligible and will not be considered for further evaluation. Reasons for rejection of a Bidder or its bid include:

a) Receipt of Intent to Bid and Bidder's Credit Information forms or any proposal after the response deadline.
b) Failure to meet the requirements and provide all of the information requested in **Appendix C-1, Appendix C-2** and or **Appendix C-3** of this RFP.
c) Failure to permit disclosure of information contained in the proposal to PacifiCorp's agents, contractors, regulators, or non-bidding parties to regulatory proceedings under appropriate confidentiality agreements.
d) Any attempt to influence PacifiCorp in the evaluation of the proposals, outside the solicitation process.
e) Any failure to disclose the real parties of interest in the proposal submitted.
f) The Bidder, or an affiliate of Bidder, is in current litigation with PacifiCorp or has, in writing, threatened litigation against PacifiCorp, respecting an amount in dispute in excess of one million dollars.
g) Proposal has failed to clearly specify all pricing terms.
h) Proposal has failed to offer unit contingent (as generated) or system firm capacity and energy, delivered into or in PACW or PACE and include appropriate contract term lengths and commercial operation dates.
i) Proposal presents unacceptable level of development and technology risk.
j) Failure to demonstrate a contract to purchase major equipment (i.e., wind turbines) and a process to adequately acquire other critical long lead time equipment.
k) Bidder fails to demonstrate, to PacifiCorp's satisfaction, that it can meet the security requirements for each Renewable Resource proposed consistent with the requirements in **Appendix D** provided in this RFP.
m) Bidder fails to address satisfactorily both the price and non-price factors.
n) Bidder fails or is unable to abide by the applicable safety standards.
o) The Bidder submits an unacceptable contract structure.
p) Collusive bidding or any other anticompetitive behavior or conduct exists.
q) Bidder or project being bid is involved in bankruptcy proceedings.
r) Failure of the Bidder's authorized officer to sign the proposal.
s) Misrepresentation or failure to abide by National Association of Attorneys General (NAAG) Environmental Marketing Guidelines (available at http://www.naag.org/issues/pdf/Green_Marketing_guidelines.pdf).
t) Any change in regulations or regulatory requirements that make the Bidder's proposal non-conforming.
u) Any matter impairing the Bidder, the specified resources or the generation of power or Environmental Attributes of the Renewable Resource.
v) Failure to provide one year worth of viable wind data.
w) Failure to provide a third party wind study or equivalent to support the capacity factor of the project.

H. COMPANY RESERVATION OF RIGHTS AND DISCLAMERS

The Company reserves the right, without qualification and in its sole discretion, to reject any or all bids, and to terminate this RFP in whole or in part at any time. Without limiting the foregoing, the Company reserves the right to reject as non responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined in Section 4. The Company also reserves the right to request that the IE contact any Bidder for additional information. The Company further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any Bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact the Company and/or any collusive bidding or other anticompetitive behavior or conduct.

Bidders who submit bid proposals do so without recourse against PacifiCorp, its parent company, its affiliates and its subsidiaries, or against any director, officer, employee, agent or representative of any of them, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. Bidders will be required to execute the non-reliance Agreement in **Appendix H** after the Final Shortlist and prior to entering into final negotiations.

I. ACCOUNTING

All proposals will be assessed by PacifiCorp for appropriate accounting or tax treatment. Bidders must supply all information PacifiCorp reasonably requires in order to make such assessments.

Specifically, accounting and tax rules may require that: (i) a contract is accounted for by PacifiCorp as a Capital Lease or Operating Lease,[7] or (ii) the seller or assets owned by the seller be consolidated as a Variable Interest Entity[8] (VIE) onto PacifiCorp's balance sheet.

Each Bidder must also agree to make available at any point in the bid evaluation process, any and all financial data associated with the Bidder, the Facility and the PPA, Asset Acquisition and Sale Agreement or BOT that PacifiCorp requires to determine potential accounting impacts. Such information, including data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset) associated with the Bidder's proposal. Financial data contained in the Bidder's financial statements (e.g., income statements, balance sheets, etc.) may also be required to provide additional information.

J. CONFIDENTIALITY

PacifiCorp will attempt to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the Bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark an entire

[7] "Capital Lease" and "Operating Lease" - shall have the meaning as set forth in the Statement of Financial Accounting Standards (SFAS) No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.
[8] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the FASB.

proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

All information supplied to PacifiCorp or generated internally by PacifiCorp shall remain the property of PacifiCorp. Bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during or after this RFP process unless required by law or regulatory order. The Bidder expressly acknowledges that PacifiCorp may retain information submitted by the Bidder in connection with this RFP.

Only those Company employees who are directly involved in this RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or Bidder information.

Bidders should be aware that information supplied by Bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions applicable to that particular proceeding. This means that parties to regulatory proceedings may request and view confidential information. If such a request occurs, PacifiCorp will attempt to prevent such confidential Bidder information from being supplied to intervening parties who are Bidders or who may be providing services to a Bidder, but PacifiCorp can not promise success in that endeavor and accordingly cannot be held liable for any information that it is ordered to be released or that is inadvertently released.

Lastly, PacifiCorp intends to utilize its internal, proprietary, forward price projections in its evaluation process. The resulting projections and evaluations will not be shared with entities external to PacifiCorp or its consultants, including with Bidders, unless required by law or regulatory order.

Bidders will be required to execute the confidentiality agreement included as **Appendix G** to this solicitation after the Final Shortlist and prior to entering into final negotiations.

SECTION 4. REQUEST FOR PROPOSAL CONTENT

Bidders can submit proposals for either (A) a Power Purchase Agreement (PPA), (B) a Build Own Transfer (BOT) or (C) Asset Acquisition and Sale Agreement.

A. POWER PURCHASE AGREEMENT

Appendix C-1 contains an explanation of the information required if a Bidder plans to pursue the PPA option. The Bidder would agree to meet its contractual obligations within the PPA during the Term of the Agreement agreeing to sell the Project to PacifiCorp at the end of the term as outlined in Section 5.6 of the PPA (**Appendix E**) or during the term of the PPA as outlined by the Bidder. The Bidder's proposal must contain the information requested in **Appendices B, C-1, D, J,** and any proposed changes to **Appendix E.** The Bidder must provide information sufficient to assure PacifiCorp that any proposed project has a reasonable probability of successful construction and operation by December 31, 2012.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor under a single engineer, procure, and construct (EPC) contract or an equivalent structure which will not increase the risk of default by multiple contractors to PacifiCorp and its customers. Any Contractor must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity must have a Credit Rating (as defined in Appendix D) that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp, or otherwise provide credit assurances **from a credit support provider acceptable to PacifiCorp in its sole discretion.**

B. BUILD OWN TRANSFER

Appendix C-2 contains an explanation of the information required if a Bidder plans to pursue the BOT option. The Bidder's proposal must contain the information requested in **Appendices B, C-2, D, J,** and any proposed changes to **F**. The Bidder must provide information sufficient to assure PacifiCorp that any proposed project has a reasonable probability of successful construction and operation by December 31, 2012.

Under the BOT option, PacifiCorp and the entity building the project must be counterparties. The BOT *pro forma* documents are attached as **Appendix F**. A BOT can be structured with progress payments with defined milestones, or as a single lump sum payment due upon achievement of commercial operation. PacifiCorp will in no event make progress payments to a Bidder unless each such payment results in the transfer of a tangible asset or a percentage ownership of an asset at the time each payment is made. Bidders must submit bids that comply with one of these two payment structures. All Bidders in this category must complete the information requested in **Appendix C-2**.

PacifiCorp will only accept proposals in which PacifiCorp purchases a fully completed project which has reached commercial operation. Any proposals that consist of either only a site sale or only an EPC contract will be rejected as a nonconforming proposal.

The Bidder shall be responsible for all aspects of the development and construction of the facility, including, but not limited to, permitting, engineering, procurement, construction, interconnection and all related costs up to achieving commercial operation. Without limiting the foregoing, the Bidder shall be responsible for obtaining all rights and resources required to construct and provide an operational generation resource consistent with the Bidder's proposal.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor, which must be a party to the BOT. To the extent the Bidder uses a Contractor or a separate legal entity other than the Bidder itself, this entity must be a party to the EPC and must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity must have a Credit Rating that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp, or otherwise provide adequate credit assurances from a credit support provider acceptable to PacifiCorp in its sole discretion.

C. ASSET ACQUISITION AND SALE AGREEMENT

Appendix C-3 contains an explanation of the information required if a Bidder plans to pursue the Asset Acquisition and Sale Agreement. The Bidder's proposal must contain the information requested in **Appendices B, C-3, D, J,** and any proposed changes to **F**. The Bidder must provide information sufficient to assure PacifiCorp that any proposed project is currently under operation.

For the acquisition of an existing asset, the Asset Acquisition and Sale Agreement pro forma documents are attached as **Appendix F**.

PacifiCorp will only accept proposals in which PacifiCorp purchases a fully completed project which has reached commercial operation. Bidders should note that any proposal submitted in this category will be subject to due diligence by the company.

SECTION 5. RESOURCE INFORMATION

PacifiCorp shall rely on the outcome from this RFP to ascertain the most prudent resource decision(s). PacifiCorp's IRP is a comprehensive decision support tool and road map for meeting PacifiCorp's objective of providing reliable and least-cost electric service to all of its customers while addressing the substantial risks inherent in the electric utility business. Bidders should note that the IRP report is a useful document for information purposes and Bidders should not infer in any way that the IRP should prescriptively guide their specific proposal. PacifiCorp's 2008 IRP is available at www.pacificorp.com/Navigation/Navigation23807.

A. PRICE AND NON-PRICE INFORMATION

Bids will be evaluated on the basis of price and non-price factors to determine the Initial Shortlist. The bids on the Initial Shortlist will then be evaluated using the IRP models to determine the Final Shortlist.

The Initial Shortlist will consist of Price and Non-Price factors.

The Price factors will be determined using the comparison metric which will be the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The net PVRR component views the value of the energy and capacity as a positive, and the offsetting costs as negative. The more positive the net PVRR, the more valuable a given resource is to PacifiCorp's customers. The net PVRR/kW-mo metric is the annuity value which, when applied to the nominal kilowatts on a monthly basis and present-valued, will result in the same net PVRR as a straight NPV calculation[9]

[9]The term "straight NPV calculation" refers to the act of present-valuing the net of the nominal capacity and energy value, and costs, to derive a net present value of the net margin between value and costs. To the extent a significant number of the proposals are above 140% of adjusted appropriate price curve in the two initial shortlists, such proposals will be ranked on a percentage in order to apply a ranking for price.

with the appropriate adjustments. There will be three Initial Shortlists. The shortlists will consist of 1) west wind resource, 2) east wind resources and 3) all other renewable resource types. If provided, up to 500 megawatts of viable bids will be shortlist in each of the two Initial Shortlists and will move from the Initial Shortlist to the Final Shortlist.

The Non-Price factors will include without limitation, positive or negative 1) conformity to RFP bid requirements (**Appendix B**), 2) conformity to the form power purchase agreement (**Appendix E**) or BOT and or the Asset Acquisition and Sale Agreements (**Appendix F**), 3) development and feasibility of proposal, 4) site control and permitting, and 5) operational viability. Price factors will recognize the value of the power (e.g., firm versus non-firm, delivery shape, and the relative value of environmental attributes associated with the facilities).

All bids must include exclusive ownership by PacifiCorp of any and all Environmental Attributes[10] associated with all energy generated.

A.1. PRICE INFORMATION

PacifiCorp is willing to consider the following contract structures so long as the Bidder supplies sufficient information to permit effective evaluation:

- *Power purchase agreements with purchase options* – for the initial term of the power purchase agreement Bidder owns the asset and PacifiCorp purchases the output. At some defined point in time PacifiCorp may have the option to purchase the asset at the end or during the Term of the power purchase agreement subject to the terms and conditions of the Bidder.

  For PPAs, PacifiCorp is willing to consider the following delivery concepts so long as the Bidder supplies statistically valid information to permit effective evaluation:

  - Unit contingent generation as generated by the facility interconnected directly to PacifiCorp's transmission system

  - Firm, scheduled generation into PacifiCorp's system

  - Generation from other systems telemetered into PacifiCorp's system if adequate third party transmission is available.

- *Build Own Transfer* –Bidder sells a fixed price turn key project payable in a single amount on delivery or upon achievement of milestones as progress payments, with an online date prior to December 31, 2012.

- *Purchase of an existing asset* – Bidder sells an operating existing asset or the equity in the asset at a fixed price. The sale will be contingent on the company completing its due diligence on the exiting operating asset.

[10] As defined in the Power Purchase Agreement.

A.2 NON-PRICE INFORMATION

Non-price factors will include without limitation positive or negative 1) conformity to RFP bid requirements (**Appendix B**), 2) conformity to the form of power purchase agreement (**Appendix E**), build own transfer agreement and Asset Acquisition and Sale Agreement (**Appendix F**), 3) feasibility of proposal, 4) site control and permitting, and 5) operational viability.

This RFP is requesting cost-effective resources that are capable for delivery into or in PacifiCorp's network transmission system[11] in PACE or PACW. All proposals will be contingent on transmission and must be ability to be designate by PacifiCorp commercial and trading function as a Network Resource under the network service contract between PacifiCorp Transmission (www.oasis.pacificorp.com) and PacifiCorp Commercial and Trading.

B. POINT OF DELIVERY

PacifiCorp is interested in resources that are capable of delivery into or in PacifiCorp's network transmission system in PACE or PACW. Specifically, the point(s) of delivery of primary interest to PacifiCorp are:

Eastern Control Area (PACE)

- Salt Lake Valley
- Mona[12] 345 kV
- Glen Canyon 230 kV
- Nevada/Utah Border:
    - Gonder-Pavant 230 kV line known as "Gonder 230 kV"
    - Sigurd – Harry Allen 345 line known as "NUB" or Red Butte 345 kV
- Wyoming- delivery points will require site specific evaluation for integration.
- Borah, Brady or Kinport if such resource is interconnected to PacifiCorp's Southwest Idaho electrical system near the Goshen 161 kV area.

Western Control Area (PACW)

- Mid Columbia
- Paul 500kV
- California Oregon Border
- PACW System
    - Within the Western Control Area – The point of interconnection between the resource, or the electrical system to which the resource is connected, and PacifiCorp's transmission system.[13]

[11] Any costs required to upgrade PacifiCorp's electrical infrastructure incremental to those contained in the IRP will be considered in the overall economics of the resource. PacifiCorp will use the best available information at the time of evaluation to determine the integration costs for the analysis.
[12] PacifiCorp's transmission function has broken Mona into three distinct delivery points. These three points are "MDWP" (IPP-Mona from LADWP control area), "MDGT" (Bonanza-Mona within the PACE control area), and "MPAC" (all other lines into Mona with the PACE control areas).

- Scheduled to the point(s) of interconnection between PacifiCorp's western control area and the Bonneville Power Administration or Portland General Electric such that transfer limitations are not exceeded. If the source located within the Bonneville the Bidder must show they have control area service from the resource to the delivery point.

C. THIRD-PARTY INTERCONNECTION AND INTEGRATION AND TRANSMISSION SERVICE

PPA Bidders are responsible for any interconnection, electric losses, reserves, transmission, integration tariffs, imbalance tariffs, and ancillary service arrangements required to deliver the proposed firm capacity and associated energy to the bid specified Point(s) of Delivery. Such costs will be included in the evaluation of the proposals. All proposals must identify all third-party interconnection, electric losses, transmission and ancillary service products, provider of reserves, and must provide a complete description of those service agreements, and provide documentation that such service(s) will be available to during the full term of offer(s) proposed or that contractual roll-over options if available.

Bidders who propose bids relying on third-party transmission should be aware that the use of transmission that is interruptible within the hour in any segment of the schedule or tagged from the source to the Point(s) of Delivery will require PacifiCorp to evaluate the need to carry reserves against the schedule, which can be up to 100% in the case of electricity moved from a third party control area to PACE or PACW.

[13] Willamette Valley
Alvey 230 kV
Chiloquin 230 kV
Dixonville 230 kV
Fry 230 kV
Meridian 230 kV
Reston 230 kV

Central Oregon – Deschutes Valley
Bend 69 kV
Pilot Butte 69/230 kV
Ponderosa 230 kV
Redmond 69 kV

Yakima Area – Mid Columbia
Midway 230 kV
Wanapum 230 kV

Oregon Coast
Astoria to Tillamook 115 kV
Boyer (Lincoln City) 115 kV
Fairview (Coos Bay) 115/230 kV
Alvey 500 kV
Chiloquin 230 kV
Dixonville 230 kV
Fry 230 kV
Meridian 230 kV
Reston 230 kV

D. STANDARDS OF CONDUCT

Each Bidder responding to this RFP must conduct its communications, implementation and operations in compliance with FERC's Standards of Conduct for Transmission Providers, requiring the separation of its transmission and merchant functions. The third-party transmission service is NOT a transmission service agreement with PacifiCorp's commercial and trading function; rather it is with PacifiCorp's transmission function or other third-party transmission providers, and hence absolutely no communication by a Bidder to PacifiCorp's transmission function can be made through the submission of a bid in this RFP. Any bid seeking to do so will be summarily rejected if the attempt is not immediately withdrawn when discovered. If requested, short-listed Bidders shall execute a customer consent consistent with FERC requirement that enables PacifiCorp's merchant function to discuss the Bidder's interconnection and/or transmission service application(s) with the transmission interconnection or transmission service provider.

E. TRANSMISSION INTERCONNECTION AND TRANSMISSION SERVICES

This RFP requires that all Bidders must enter into a separate Interconnection Agreement if their facilities are located within the PacifiCorp footprint in accordance with PacifiCorp's Open Access Transmission Tariff. Bidders must advise PacifiCorp Transmission if any such service is being requested as part of this RFP. Bidders requiring interconnection service from PacifiCorp Transmission must request Energy Resource (ER) service. As stated above, all such requests, if made, must be made directly to PacifiCorp's transmission function through OASIS or other applicable tariffs, and not made to PacifiCorp through the submission of a bid in this RFP. Any bid seeking to do so will be summarily rejected if the attempt is not immediately withdrawn when discovered.

All proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include a statement of the cost of interconnection (broken out between network upgrade costs and facility specific or direct assigned interconnection costs), together with a diagram of the interconnection facilities. The Bidder will be responsible for, and is required to include in its bid, all costs to interconnect to the transmission provider's system. The Bidder will be responsible for applying to the transmission provider for a Large Generator Interconnection Agreement (LGIA). The interconnection costs from all Bidders will be included in the bid evaluation. Bidders shall describe interconnection costs in their bids by disclosing that portion of costs associated with network upgrades and that portion that is facility specific. Bidders are reminded that they shall bear 100% of the costs to interconnect to the transmission provider's system. Bidders are encouraged to contact the applicable transmission function (i.e., PacifiCorp's transmission function at www.oasis.pacificorp.com) for information related to a system interconnection request. As stated above, all such requests, if made, must be made directly to PacifiCorp's transmission function through OASIS or other applicable tariffs, and not made to PacifiCorp through the submission of a bid in this RFP. Any bid seeking to do so will be summarily rejected if the attempt is not immediately withdrawn when discovered.

Once the Bidder is selected, the applicable transmission function typically has the option of funding the interconnection network upgrades or requiring the Bidder to fund such network upgrades and then receive revenue credits per the applicable OATT. Any such refunds shall be assigned to PacifiCorp directly or through a three-party contract, with the transmission provider treated as an independent third party; provided, however, if the Bidder is interconnecting to a third party and is scheduling power for delivery to PacifiCorp's control area using third party transmission then the refund shall remain with the Bidder.

F. PACIFICORP TRANSMISSION INTEGRATION SERVICE

Notwithstanding the foregoing, Bidders should not factor in the cost of integrating the proposed resources from bid-specified Points of Delivery to PacifiCorp's system. Such transmission integration costs and other integration costs will be factored in for determination of the Final Shortlist. These costs do not include interconnection costs. Transmission and other integration costs incremental to those in the IRP will be taken into account within the final analysis. Integration costs consistent with the IRP will be added to all bids.

After the Initial Shortlist is selected, the Structuring and Pricing group will provide the results of the initial Short list to the IRP Group. Pursuant to a consulting agreement between the IRP Group and PacifiCorp Transmission, PacifiCorp Transmission will provide more refined cost estimates associated with integrating the Short-listed resources into PacifiCorp's system. The IRP group will seek updated costs from PacifiCorp Transmission for only the Short-listed Bidders. These integration costs will be used as inputs into the IRP model along with the Short-listed proposals in order to determine the final Short list.

G. RESOURCE TYPES ELIGIBLE TO BID

The Renewable Resource must have a commercial operation date no later than December 31, 2012. Facilities generating power from the resource types defined as Renewable Resources in Section 1 are eligible to be the subject of bids under this RFP, provided they are capable of delivering at least 25,000 MWh per year. In addition, qualifying facilities with a nameplate of 10 megawatts or greater are eligible to bid.

Any resource considered pursuant to this RFP must be capable of clearly verifying time and amount of delivery of energy from the resource by metering or other means acceptable to PacifiCorp including without limitation metering on less than or equal to an hourly basis.

This solicitation is for proposals that offer *both* RECs and underlying generation from an associated Renewable Resource and <u>not</u> RECs only or RECs bundled with market purchases. Proposals that offer only Environmental Attributes or a rebundled product will be rejected.

H. PRODUCTION TAX CREDIT AND INVESTMENT TAX CREDIT

Bidders shall bear all risks, financial and otherwise, associated with Bidder's or the facility's eligibility to receive production or investment tax credits or qualify for accelerated depreciation for Bidder's accounting, reporting or tax purposes. The obligations of the Bidder to perform under any executed agreement as a result of this solicitation shall be effective and binding regardless of whether the sale of output from the Bidder's facility under such agreement is eligible for, or receives, production or investment tax credits during the term of the agreement.

I. ACCOUNTING

All contracts proposed to be entered into as a result of this RFP will be assessed by the Company for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with any and all information that the Company reasonably requires in order to make such assessments. Specifically, given the term lengths that Build own Transfer or Power Purchase Agreements accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a Capital Lease or Operating Lease[14] pursuant to SFAS No. 13, or (ii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a Variable Interest Entity[15] (VIE) onto PacifiCorp's balance sheet. To the extent a Bidder's proposal results in an applicable contract, the following shall apply with respect to VIE treatment:

The Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, after Bidders are selected in the Final Shortlist, if required by the Company accounting department, Bidders will be required to certify, with supporting information sufficient to enable the Company to independently verify such certification, that their proposals will not be subject to VIE treatment. Bids that result in VIE treatment will be rejected after they are given an opportunity to provide an alternate structure that does not trigger a VIE, which will be subject to consultation with the IE and PacifiCorp's advisors.

Each Bidder must also agree to make available at any point in the bid evaluation process, any and all financial data associated with the Bidder power purchase agreement, build own transfer and or Asset Acquisition and Sale Agreement that PacifiCorp requires to determine potential accounting impacts. Such information may include, but may not be limited to, data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's proposal. Financial data contained in the Bidder's financial statements (e.g., income statements, balance sheets, etc.) may also be required to provide additional information.

[14] "Capital Lease" and "Operating Lease" - shall have the meaning as set forth in the Statement of Financial Accounting Standards (SFAS) No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.

[15] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the FASB.

To the extent PacifiCorp rejects a proposal submitted in this RFP because it triggers VIE treatment, PacifiCorp shall provide documentation to the IE justifying the basis for its decision.

J. COST ASSOCIATED WITH DIRECT OR INFERRED DEBT

PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt (described below) as part of its economic analysis in the initial or Final Shortlist evaluation. However, after completing the Final Shortlist and before the final resource selections are submitted for acknowledgement by the Oregon Commission, the Company may take into consideration, in seeking approval, cost recovery or acknowledgement with respect to selected resources, any projected costs of direct or inferred debt. The Company will bear the burden to demonstrate to the satisfaction of its regulators the validity, magnitude and impacts of any such projected costs. At the request of the Utah or Oregon Commission, PacifiCorp will be required to obtain a written advisory opinion from a rating agency to substantiate the utility's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a Capital Lease pursuant to EITF 01-08 and SFAS No. 13 and the lower of the present value of the nonexecutory minimum lease payments or 100% of the fair market value of the asset must be added to PacifiCorp's balance sheet.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing PacifiCorp's credit standing.

SECTION 6. BID EVALUATION AND SELECTION

PacifiCorp will utilize a "first-price sealed bid format" in order to generate an initial short list. The initial short list constitutes the bids that will be evaluated with the IRP models, and from which the final short-listed bids will be selected for any post-bid negotiations.

Under this format, contract payments are based on the price contained in each winning bid proposal. The "first-price sealed bid format" means that PacifiCorp will utilize the initial prices and pricing structure submitted by the Bidder in order to determine the initial short-listed entities. PacifiCorp will not ask for, or accept, updated pricing from Bidders during the evaluation period. **PacifiCorp will negotiate both price and non-price issues after the Initial Shortlist and during post-shortlist negotiations.** PacifiCorp reserves the right not to engage in any post-bid or post-Shortlist negotiations with any Bidder that has not made the initial short list. Selection for the initial short list, the Final Shortlist and post-shortlist negotiations does not constitute a "winning bid proposal." Only execution of a definitive agreement by both PacifiCorp and the Bidder on terms acceptable to PacifiCorp in its sole and absolute discretion will constitute a "winning bid proposal." Any definitive power purchase agreement or build own transfer will be in the form of the PPA, BOT and Asset Acquisition and Sale Agreement shown in **Appendices E** and **F**, respectively. If the Bidder alters the PPA, BOT or Asset Acquisition and Sale Agreement or does not use it as the underlying agreement the bid evaluation will be effected. PacifiCorp has no legal obligation to enter into any agreement of any kind with any Bidder.

A. OVERVIEW OF THE EVALUATION PROCESS

The analysis for the RFP will be focused on determining which resources provide the best value to customers on a system-wide planning basis to meet customer requirements at the least cost, on a risk adjusted basis and in the public interest. The evaluation process will utilize a screening process to derive three Initial Shortlists of bids (described in Step 1 below) and the Final Shortlist will be determined using the integrated resource planning models, and any residual value of the project to determine the Final Shortlist.

The selection of three Initial Shortlists of bids will be based on price and non-price factors. The three Initial Shortlists will comprise of two Initial Short list for wind east and west resources and one initial shortlist for all other renewable resource types. The price factor will be derived using the PacifiCorp Structuring and Pricing RFP Base Model. The RFP Base Model determines the three Initial Shortlists of the top performing proposals on the basis of the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The non-price factors will evaluate the positive or negative 1) conformity to RFP bid requirements (**Appendix B**), 2) and the form of power purchase agreement (**Appendix E**) or build own transfer documents and or Asset Acquisition and Sale Agreement (**Appendix F**), 3) feasibility of proposal, 4) site control and permitting, and 5) operational viability.

The Initial Shortlists may contain up to 500 megawatts or 5 bids of the viable bids that qualify in the three separate Initial Shortlists from a screening basis will then be evaluated using an Integrated Resource Planning model to establish the Final Shortlist.

The Bidder is responsible for the negotiation, execution and cost of interconnecting or delivering in or into the PacifiCorp control area. The Bidder will be responsible for all incremental transmission expenses, which must be included in the bidders pricing, associated with delivery to PacifiCorp's network transmission system (inclusive of any third-party system upgrade needed to deliver such energy to PACE or PACW). If the Bidder does not provide such costs, any anticipated transmission cost which is not included in the Bidder's response or is incremental to transmission assumptions included in the IRP will be added by PacifiCorp using information reasonable and readily available during the economic evaluation phase.

Bids submitted in this RFP will be evaluated in two steps:

STEP 1—PRICE AND NON-PRICE SCREEN WILL BE USED TO DETERMINE THREE LISTS OF BIDS, TWO LIST FOR WIND RESOURCES, EAST AND WEST ,AND THE OTHER FOR ALL OTHER RENEWABLE RESOURCE TYPES. THESE THREE LISTS WILL BE DEEMED AS THE INITIAL SHORTLIST FOR SCREENING PURPOSES.

STEP 2—PACIFICORP'S PRODUCTION COST SIMULATION MODEL, USED FOR INTEGRATED RESOURCE PLANNING, WILL BE USED TO DETERMINE A LIST OF BIDS DEEMED AS THE FINAL SHORTLIST.

PacifiCorp intends to evaluate each bid received in a consistent manner by separately evaluating the non-price characteristics of the resource and the price characteristics. Each component will be evaluated separately and recombined to determine the bundled price and non-price score. The price factor will be weighted up to 70%, while the non-price factor will be weighted up to 30%. No proposal will receive a total weighting in excess of 100%. The price and non-price evaluation will be added together and used to determine the Initial Shortlist. The three Initial Shortlists will be made up of the highest scoring proposals.

B. PRICE FACTOR EVALUATION (UP TO 70%)

PacifiCorp will utilize the RFP Base Model to screen the proposals and to evaluate and determine the price ranking for the three Initial Shortlists.

The RFP Base Model is contained in a Microsoft Excel workbook that includes a number of proprietary Visual Basic macros, custom add-ins, and computational code written in C++.

<u>RFP Base Model Inputs</u>:
Market Quote Date: The model will pull corresponding forward price, volatilities, and correlation projections for electricity and fuel commodities. Treasury discount curves are also included. The same Market Quote Date will be used for all bids during each evaluation phase.

- Term: start and end date
- Transmission cost assumptions
- Rate base inputs, if applicable
- Point of delivery (POD) and Point of receipt (POR)
- Dispatch pattern
- Firm/unit contingent
- Resource type
- Product source
- Variable O&M payment ($/MWh)
- Variable O&M costs ($/MWh)
- Fixed energy payment ($/MWh, if applicable)
- Capacity charge ($/KW-mo, if applicable)

- Resource/POD availability by month
- Forward price curve multiplier by month
- Corporate financial inputs – inflation curve, WACC, etc.

Comparison Metric

The comparison metric will be the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The net PVRR component views the value of the energy and capacity as a positive, and the offsetting costs as negative. The more positive the net PVRR, the more valuable a given resource is to PacifiCorp's customers. The net PVRR/kW-mo metric is the annuity value which, when applied to the nominal kilowatts on a monthly basis and present-valued, will result in the same net PVRR as a straight NPV calculation.[16]

Bid Cost Relative to Adjusted Price Curves	Price Factor Weighting
Less than or equal to 80% of adjusted price projections	70%
Greater than 80% of adjusted price projections but less than 140% of adjusted price curves	Linearly interpolated
Equal to or greater than 140% of the adjusted price projection	0%

C. NON-PRICE FACTORS (UP TO 30%)

The primary purpose of the non-price analysis is to help gauge the factors related to the proposal which are outside of price. A matrix will be established for each non-price factor and will be used to compare the bids with one another. Non-price factors will be weighted up to 30% (in combination with the price scores) in the determination of which proposals will be chosen for the Initial Shortlist. The non-price factor criteria are identified in Chart 4 below. Bids will be evaluated and scored in five discrete categories: (1) 100% of the percentage weight; (2) 75% of the percentage weight; (3) 50% of the percentage weight; (4) 25% of the percentage weight or (5) 0% of the percentage weight. Bids will be evaluated based on their ability to demonstrate the proposal is thorough, comprehensive and provides limited risk to the customers prior to PacifiCorp performing due diligence on any given Bid. Bids which have a demonstrated track record or are mature proposals will be more highly evaluated. Chart 4 lists the key non-price criteria and the basis for weighting for each criterion. These Non-Price factors will be used in the evaluation of the Non-Price characteristics of the three categories of proposals (PPA, BOT, and Asset Acquisition), the qualifying facilities and the benchmarks.[17]

[16] The term "straight NPV calculation" refers to the act of present-valuing the net of the nominal capacity and energy value, and costs, to derive a net present value of the net margin between value and costs. To the extent that a significant number of the proposals are above 140% of adjusted price curves the two Initial Shortlists will be ranked on a percentage according to price.

[17] The benchmark resources will be evaluated on a risk adjusted basis.

CHART 4 – NON-PRICE FACTORS

Non-Price Factor	Non-Price Factor Weighting
1) Conformity to RFP requirements - has the bidder provided all the requirements pertaining to their proposals in Appendix B, C-1,C-2 or C-3, D and J	6%
2) Conformity to pro forma PPA, BOT or Asset Acquisition and Sale Agreement - has the bidder required any additions or deletions that impose additional costs and or risks to customers.	6%
3) Development and feasibility of proposal - Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail regarding the quality of their environmental compliance plan and any environmental impact of each proposal consistent with the proposed technology. Bids must demonstrate that the project can be reasonably developed within the appropriate timeframe to meet the proposed in service date and with limited risk to the customers. Bids which have achieved commercial operation will be awarded percentage weight consistent with the risk associated with each non-price category. For example, an existing project will be awarded 100% of the percentage weight associated with the Critical Path Schedule.	6%
4) Site control and permitting - Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail on the status of permitting, and site control. Bids which can demonstrate little or no risk associated with these criteria will be more highly valued	6%
5) Operational Viability - Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstrate sufficient detail of their ability to comply with environmental permits and requirements and their operating experience with similar renewable projects and technology.	6%

1) Conformity to RFP requirements

This category is intended to assess if all the requirements pertaining to Bidders and Benchmark proposals, to the extent applicable in Appendix B, C-1, C-2 or C-3, D and J have been provided and are responsive and complete.

2) Conformity to Pro Forma Agreements

This category is intended to assess if the Bidder conforms to the underlying *pro forma* agreements. IF any of the edits provided by the bidder to the underlying agreements, PPA, BOT or Asset Acquisition and Sale Agreement, shift or apply additional risks or costs to customers. If so, then the percentage will be adjusted. The percentage will not be adjusted if bidders provide edits which either add value to customers or do not impose additional costs or shift risks to customers. This category is intended to assess if the bidder conforms to the underlying *pro forma* agreements in the request for proposal. Do any of the edits provided by the bidder to the underlying agreements, PPA, BOT or Asset Acquisition and Sale Agreement, shift or apply additional risks or costs to customers. If so, then the percentage will be adjusted. The percentage will not be adjusted if bidders provide edits which either add value to customers or do not impose additional costs or shift risks to customers. Benchmark will be deemed to equal full weighting since the costs associated with any benchmark will be subject to regulatory rulings and not contracts.

3) Development Feasibility/Risk

This category is intended to assess the likelihood the Bidders' project and the benchmark resource can be successfully developed as proposed based on a number of factors which influence project development feasibility and risk of development. Factors influencing the status of project development as well as the likelihood the project will be developed on schedule will be assessed. For this category, the Company will evaluate the critical path schedule provided by the Bidders and Benchmark, the engineering design and technology maturity for the project proposed, the status of fuel supply arrangements, if any and the strategy of the Bidder and or Benchmark for securing fuel for the project, if applicable.

Bidders and benchmark shall provide a detailed project schedule with critical path milestones for the project that includes activities from the period of selection as the winning bidder to the commercial operation date. The Company will review and evaluate the project schedule to ensure there is a high likelihood the project can reach commercial operations as proposed.

Bidders and benchmark should also provide information about specific technology and equipment proposed for the project, including a description of the track record of the technology and equipment. The Bidder and benchmark should provide a detailed description and specifications for the proposed equipment. The Company reserves the right to conduct further due diligence on the equipment and project design. Bidders and benchmark should provide a detailed strategy for securing and delivering fuel to the project (for those projects other than wind) site. The Company prefers proposals that can demonstrate a secure and reliable fuel supply or strategy which demonstrates the ability of the bidder to secure or demonstrate a reliable supply for the project.

4) Site Control and Permits

Bidders and benchmark must be able to 1) document they have obtained site control and necessary permits (maximum points in this category) or 2) demonstrate how site control and permits will be obtained. To meet the site control requirement, Bidders shall have identified a site and must provide a copy of documentation establishing that the seller has and/or will have control over the site for the entire term of the contract. Eligible documentation includes a demonstration of site ownership, an option to purchase the site, or a binding letter of intent from the landowners for the full term of the contract. The Bidder and the benchmark must be able to obtain site control prior to signing a contract with the Company. For Bidders and the benchmark to demonstrate how they will obtain site control, they must submit documentation which supports the site control requirements. Bidders and the benchmark should also provide a list of all required permits that must be obtained. In addition, Bidders and the benchmark should identify any rights-of-ways that need to be acquired for the construction and provide a plan and schedule for securing the rights-of-ways.

5) Operational Viability

This category addresses key viability and risk factors associated with project operations. The two key factors of importance are first, the environmental management and compliance and any potential environmental impacts and second a description of prior operating experience of a similar project and technology. Bidders and benchmark should provide a description of the environmental management and compliance criterion for the renewable project and addresses the ability of such project, existing or to be constructed for a PPA or BOT, ability to meet all of the projects environmental compliance and permits. Second, Bidders and benchmarks should provide a description of any and all previous experience in operating and maintaining similar projects.

Step 2 – IRP – Final Shortlist

The Company will use its current renewable energy resource valuation methodology for evaluating bids for inclusion in the Final Shortlist. This methodology, called the Alternative Compliance Cost (ACC) method, uses the Company's production cost simulation system and its Forward Price Curve to generate a market-based alternative comparison of the bid resources. In determining the alternative, the Company first runs the production cost simulation system (the Planning and Risk, or PaR model) in stochastic mode using the then-current IRP preferred portfolio. The PaR model is then run a second time with the uncommitted future renewable resources removed from the preferred portfolio. The resulting production costs from this second model run reflect the market-based energy costs incurred as a result of no longer adding renewable resources to the IRP preferred portfolio. Next, other costs and benefits of the specific bid resource being considered are compared against the PaR model results. This comparison is in the form of a bid resource ACC value, which represents the resource cost, over the life of the project that yields a zero net PVRR difference with respect to the PaR model's market-based resource alternative. A negative ACC value, expressed on a dollar-per-MWh basis, indicates that the bid resource compares favorably to the market-based alternative, whereas a positive ACC value indicates that the bid resource compares unfavorably to the market-based alternative. The ACC value will also be examined on an "adjusted" basis with adjustments being made to account for (a) terminal value, (b) locational integration costs and (c) incremental capacity contribution. If the Final Shortlists have positive ACC values, the company may perform additional analysis to assess the market value of renewable energy credits, compliance with RPS requirements, and potential regulations.

D. FINAL SELECTIONS; OTHER FACTORS

The two steps described above constitute the formal evaluation process and will lead to the compilation of the Final Shortlist of resources for further negotiation. After completing the formal evaluation process described above, but before making the final resource selections to be submitted for approval or acknowledgement, the Company will take into consideration, in consultation with the IE, certain other factors that are not expressly or adequately factored into the formal evaluation process, but that are required by applicable law or Commission order to be considered. In addition the Company may evaluate and include in its final finally and prudent costs associated with direct and or indirect debt directly related with the resource procurement consistent with the information outlined in Section 5(I) and (J).

The Utah Energy Resource Procurement Act requires consideration of at least the following factors in determining whether a resource selected by the Company should be approved as in the public interest:

- 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;
- long-term and short-term impacts;
- risk;
- reliability;
- financial impacts on the affected electrical utility; and
- other factors determined by the Commission to be relevant.

Oregon Order No. 06-446, Guideline 10(d), requires that the Oregon IE evaluate the unique risks and advantages associated with a Self Build option, including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.

The Washington solicitation rules (WAC 480-107-001 et seq.) provide that ranking criteria must consider the following:

- Resource cost;
- Market-volatility risks;
- Demand side resource uncertainties;
- Resource dispatchability;
- Resource effect on system operation;
- Credit and financial risks to utility;
- Risks imposed on customers;
- Public policies regarding resource preference adopted by Washington state or the federal government;
- Environmental effects including carbon dioxide (CO_2);

- Differences in relative amounts of risk inherent among technologies, fuel sources, financing arrangements, and contract provisions; and
- Complements power acquisition goals identified in the IRP.

SECTION 7. AWARDING OF CONTRACTS

A. INVITATION

This RFP is merely an invitation to make proposals to the Company. No proposal in and of itself shall constitute a binding contract. The Company may, in its sole and absolute discretion, perform any one or more of the following:

- Determine, in consultation with the IE, which proposals are eligible for consideration as proposals in response to this RFP.
- Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each Bidder.
- Disqualify proposals contemplating resources that do not meet the definition of Renewable Resources in this RFP.
- Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
- Negotiate and request Bidders to amend any proposals.
- Select and enter into agreements with the Bidders who, in the Company's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interest of the Company, its customers, and state legal and regulatory requirements, and not necessarily on the basis of any single factor alone.
- Issue additional subsequent solicitations for proposals.
- Reject any or all proposals in whole or in part.
- Vary any timetable.
- Conduct any briefing session or further RFP process on any terms and conditions.
- Withdraw any invitation to submit a response.

B. CONFIDENTIALITY AGREEMENT

All parties will be required to sign Confidentiality Agreements if they qualify for the Final Shortlist (**Appendix F**) prior to entering into negotiations with the Company.

C. NONRELIANCE LETTER

All parties will be required to sign a nonreliance letter if they are qualify for the Final Shortlist (**Appendix H**) prior to entering into negotiations with the Company.

D. POST-BID NEGOTIATION

Prior to entering into post-bid negotiation with Bidders, selected Bidders must execute the non-reliance letter in **Appendices H**.

PacifiCorp will further negotiate both price and non-price factors during post-bid negotiations. PacifiCorp will also include in its evaluation any factor that may impact the total cost of a resource, including but not limited to all of the factors used in the Initial Shortlist cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable. Post bid negotiation will be based on PacifiCorp's cost assessment. PacifiCorp will continually update its economic and risk evaluations until both parties execute a definitive agreement acceptable to PacifiCorp in its sole and absolute discretion.

PacifiCorp shall have no obligation to enter into any agreement with any Bidder to this RFP and PacifiCorp may terminate or modify this RFP at any time without liability or obligation to any Bidder. In addition, this RFP shall not be construed as preventing PacifiCorp from entering into any agreement that PacifiCorp deems prudent, in PacifiCorp's sole opinion, at any time before, during, or after this RFP process is complete. Finally, PacifiCorp reserves the right to negotiate only with those entities who propose transactions that PacifiCorp believes in its sole discretion to have a reasonable likelihood of being executed.

E. SUBSEQUENT REGULATORY ACTION

Unless mutually agreed between the parties or unless required by actual (or proposed) law or regulatory order, at the time of contract execution, PacifiCorp does not intend to include a contractual clause whereby PacifiCorp is allowed to adjust contract prices in the event that an entity who has regulatory jurisdiction over PacifiCorp does not fully recognize the contract prices in determining PacifiCorp's revenue requirement. As of the issuance date for this solicitation, PacifiCorp is unaware of any such actual law or regulatory order.

Docket No. UM-1182
Exhibit PAC/202
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

PacifiCorp
Oregon All Source Request for Proposal
2016 Resource

Issued April 4, 2012
Responses May 9, 2012

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SECTION 1. INTRODUCTION

The purpose of this document is to prescribe the process by which PacifiCorp (the "Company") will request and evaluate proposals from Bidders to fulfill a portion of the capacity and energy resource needs identified in the Company's 2008 Integrated Resource Plan, as updated ("IRP") and the 2011 IRP which is currently pending acknowledgement before the Oregon Public Utility Commission ("Oregon Commission") and Utah Public Service Commission ("Utah Commission"). The scope of this All Source Request for Proposals ("RFP"), subject to the limitations described herein, is focused on system-wide, east and west balancing authority area ("BAA"), energy and capacity[1] generation which is capable of delivering energy and capacity in or to the Company's Network Transmission system[2] (www.oasis.pacificorp.com). This RFP is seeking capacity and energy resources to serve PacifiCorp's entire system. Bids from new or existing coal resources will only be considered by the Company if such proposals are consistent with Cal. Pub. Util. Code § 8340 (2006); and Utah Code Ann. § 54-17-502, *et seq.* and amending Utah Code Ann. §§ 54-2-1, 54-12-1, 54-12-2, 54-12-3, 54-17-201, 54-17-302 and 54-17-303; Wash. Rev. Code Ann. §§ 80.80.005, 80.80.010, 80.80.030 80.80.080 (2007); and Or. Rev. Stat. §§ 757.522, 757.524, 757.528, 757.531 and 757.533 (2009); and any additional state or federal requirements regarding new and existing resources that may be identified by the Company during the solicitation process. Thus, for example, because California and Washington laws cited above do not allow the Company the opportunity to recover costs associated with long-term coal resources, bids from new or existing coal resources shall be limited to a Maximum Term[3] of less than five (5) years. Bidders may propose any of eight (8) different Resource Alternative structures in three (3) separate Bid Categories. Proposals must identify the Resource Alternative and the Bid Category. The Bid Categories are separated into Base Load, Intermediate Load and Summer Peak resources as set forth below.[4] Each Bid Category will be screened to determine the initial shortlist and the top bids will then be input into the IRP models to determine the Final Shortlist.

Bid Category	Capacity Factor
1) Base Load	> 60%
2) Intermediate Load	20-60%
3) Summer Peak Q3 purchases	July-September HE 07 through HE 22 PPT

[1] Generating resources may include renewable resources only if the resource can be dispatched or scheduled by PacifiCorp ("Eligible Renewable Resources").
[2] Company's East Balancing Authority Area ("PACE") and/or the Company's West Balancing Authority Area ("PACW").
[3] Maximum Term of under five (5) years means a term greater than one (1) year but less than five (5) years.
[4] Section II of this RFP outlines guidelines offered by the Company to assist Bidders in identifying the Bid Category for each proposal.

All energy and capacity resources must provide unit contingent or firm resource capacity and associated energy that are incremental to the Company's existing capacity and energy resources and the resource must be available and ready to be dispatched or scheduled by June 1, 2016 (the "Eligible Online Date") by the Company.[5] To the extent Bidders propose resources that will be available to the Company for dispatch or scheduling prior to June 1, 2016, Bidders must request alternative online dates. Bidders must submit request for alternative eligible dates via the Independent Evaluators' ("IEs") website at least 30 calendar days prior to the bid due date.

The Company and IEs will review the request for each Bidder proposal and make a determination as to whether or not the alternative online date will be classified as an approved eligible date. Bidders must specify the online date for each resource proposed.

The Company will not submit a benchmark resource proposal for any category. The Company will develop an initial shortlist comprised of top-performing bids in each of the three (3) Bid Categories. The Company will target to select up to twice the megawatt quantity in each of the three Bid Categories. All assumptions and inputs that the Company will use in the evaluation of Bidder proposals will be provided and locked down with the IEs prior to receipt of proposals. The Company will then request best and final pricing from the Bidders whose proposals were selected to the initial shortlist. Twenty (20) days prior to the date best and final pricing is due, the Company may update assumptions used to evaluate proposals and provide them to the IEs. The IEs will review and provide feedback to the Company within ten (10) working days after any assumption updates are delivered and the Company will lock down the assumptions and inputs prior to the receipt of best and final pricing from Bidders. Any assumption updates will be made using the same methodology used to lock down assumptions prior to issuance of the RFP. To the extent any updated modeling assumptions shift the timing and size of the resource requirement, the Company will rerun the system optimizer using the updated resource portfolio as the Baseline Portfolio. In coordination with the IEs, the appropriate resources will be removed from this updated resource portfolio to create a need that can be filled by Bidder proposals with costs that are consistent with best and final pricing.

The following table sets forth the Company's 2011 Integrated Resource Plan preferred portfolio indicating the generic combined-cycle combustion turbine (CCCT) resource selected for 2016.

[5] The Company may allow on-line flexibility consistent with the resource need identified in the Capacity Load and Resource Balance; however, a resource must be online by June 1, 2016.

	Capacity (MW)									
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCCT F Class	-	-	-	625	-	597	-	-	-	-
CCCT H Class	-	-	-	-	-	-	-	-	475	-
Coal Plant Turbine Upgrades	12	19	6	-	-	18	-	8	-	-
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200
CHP - Biomass	5	5	5	5	5	5	5	5	5	5
DSM, Class 1	6	70	57	20	97	-	-	-	-	-
DSM, Class 2	108	114	110	118	122	124	126	120	122	125
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-
Micro Solar - Water Heating	-	4	4	4	4	4	4	4	-	-
Front Office Transactions	350	1,240	1,429	1,190	1,149	775	822	967	695	995

Note: Front office transaction (firm market purchases) reflect one-year transaction periods, and are not additive.

Calendar Year	2016
East	
East Existing Resources	7,949
East Obligation	8,946
East Reserves*	1,117
East Obligation + Reserves*	10,063
East Position	(2,114)
East Reserve Margin	(11%)
West	
West Existing Resources	3,447
West Obligation	3,649
West Reserves*	452
West Obligation + Reserves*	4,100
West Position	(653)
West Reserve Margin	(5%)
System	
Total Resources	11,397
System Obligation	12,595
System Reserves*	1,569
Obligation + 13% Planning Reserves*	14,164
System Position	(2,767)
Reserve Margin	(9%)

Bidders should note that although from a planning basis the IRP identifies specific types of resources in the preferred portfolio, this should not be considered by Bidders to be the only resource type or technology that the Company is willing to consider. The 2011 IRP assumes a 13% planning margin. Planned renewable targets, conservation and demand side management[6] resources are not included for purposes of calculating resource needs for this RFP. The renewable targets, conservation and demand side management resources will be included as fixed resources for System Optimizer (SO) modeling (which is discussed in more detail in Section 6). The Company may opt to contract for more or less capacity and energy depending upon, among other things, bids received in response to the RFP, purchases apart from this RFP, quality of bids received in response to this RFP, updates to the Company's forecasts, regional transmission availability and timing, procurement of shorter term resources or intermittent resources, and changes in wholesale market conditions.

In order to provide for a transparent and fair process, the RFP will be conducted under the oversight of IEs. An IE hired by the Utah Commission and an IE retained by the Company on behalf of the Oregon Commission will be involved in all aspects of receiving, evaluating, and ranking bids in response to this RFP, and in ensuring fairness throughout the RFP process. Potential bidders are invited and encouraged to contact either of the IEs with questions or concerns.

More information concerning the role of the IEs is provided in **Attachment 18**. Contact information for the IEs is as follows:

Utah Independent Evaluators: Merrimack Energy Group, Inc.
http://www.merrimackenergy.com/PacifiCorp2011RFP/index.asp
Oregon Independent Evaluators: Boston Pacific Company, Inc.
fmossburg@bostonpacific.com

Upon conclusion of the RFP process, PacifiCorp will request the Utah Commission to approve the selected resource(s). The Company will seek regulatory acknowledgement of the Final Shortlist consistent with Oregon Order No. 06-446. PacifiCorp will also seek rate recovery consistent with standard rate making practices in its six state jurisdictions.

This introductory Section 1 describes the type, timing and amount of resources sought for delivery by June 1, 2016. Section 2 addresses the Resource Alternatives, proposal characteristics and proposal options. Section 3 addresses logistics including where and when proposals must be submitted, bid fees and minimum requirements, as well as important conditions and procedures. Section 4 provides the required content and format for all Resource Alternatives. Section 5 outlines resource information including price and non-price information, integration, interconnection and transmission services, and use of PacifiCorp sites. Section 6 outlines the bid evaluation process. Section 7 outlines the awarding and rejecting of proposals. All of the required Appendices, Attachments and Forms for each of the Resource Alternatives are also provided.

[6]A separate RFP will solicit demand side management resources. Conservation is included in the Company's load forecast.

SECTION 2. RESOURCE ALTERNATIVES AND PROPOSAL CHARACTERICS

The Company is seeking approximately 600 MW of cost-effective resource(s) consisting of Base Load, Intermediate Load and Summer Peak Q3 resources to meet the Company's System Position beginning June, 2016. See **Attachment 1** for a description of the technology, configurations, fuel type, location, projected life, transmission requirements and operation and dispatch characteristics for the EPC Resource Alternative. Unless exceptions apply as identified in the summary of Resource Alternatives later in this section, a Bidder's proposal must exceed or equal 100 MW and have a fixed term of at least five (5) years. Resource(s) bid(s) proposed by Bidders must provide unit contingent or firm capacity and associated energy incremental to the Company's existing capacity and further be available for dispatch or scheduling by the Eligible Online Date.

The Company will consider each Resource Alternative proposed by the Bidders in one of three Bid Categories: Base Load, Intermediate Load or Summer Peak Q3. Bidders are required to identify one of the three Bid Categories for each Resource Alternative proposed.[7] To help Bidders identify a Bid Category, the Company offers the following guidelines:

- Base Load Bid Category: a Resource Alternative likely to exhibit a capacity factor at or above 60% over the proposed term.
- Intermediate Load Bid Category: a Resource Alternative likely to exhibit a capacity factor between 20% and 60% over the proposed term.
- Summer Peak Q3: a Resource Alternative that will be purchased by the Company in the months of July through September in hours ending 07 through 22 Pacific Prevailing time that either includes or excludes NERC holidays and Sundays over the proposed term.

In addition to identifying the Bid Category, Bidders are required to propose one of the following Resource Alternatives: (1) Power Purchase Agreement (PPA); (2) Tolling Service Agreement (TSA); (3) Engineering Procurement Contract (EPC) on Company defined site built to Company's specifications or Asset Purchase and Sale Agreement (APSA) on Company defined site built to Company's specifications; (4) Asset Purchase and Sale Agreement (APSA on Bidder's site; (5) purchase of an existing facility; (6) purchase of a portion of a facility jointly owned or operated by the Company; (7) restructuring of an existing PPA or Exchange Agreement and /or buyback of an existing sales agreement; or (8) Exceptions which include (a) Load Curtailment, (b) Qualified Facility (QF) or (c) Eligible Renewable Resources. Descriptions of each of these

[7] Bidders can propose the same Resource Alternative into more than one Bid Category: however, for purposes of this RFP, proposals bid into more than one Bid Category will be required to submit a bid fee for each Bid Category proposed. The Initial Shortlist will be developed for each of the three Bid Categories identified in this RFP.

Resource Alternatives are set forth below.

CHART 1

Resource Alternatives	Term	Location	Requirements
1) PPAs	Fixed term specified in the bid up to the life of the asset from a single resource located in or delivering to PACE or PACW under the PPA. Must be a minimum term of 5 years and a minimum of 100 MW. A PPA not backed by assets or backed by a coal resource is limited to a Maximum Term[8] of less than 5 years, and a minimum of 100 MW.	Bidders can bid on their sites, however, PacifiCorp is not required to operate the facilities	**Attachment 3, 19 and Appendix C-1, D, F.**
2) TSAs	Same as #1	Same as #1	**Attachment 5, 19 and Appendix C-1, D, F.**
3) EPC /APSA on PacifiCorp defined site	Life of the asset will be evaluated consistent with 2011 IRP Tables 6.1-6.4. [9]	Currant Creek site	Bids pursuant to the APSA, or Bids that result in an engineering, procurement, construction, commissioning, and turnover of a facility that complies with the

[8] Maximum Term of less than five (5) years means a term of greater than one (1) year but less than five (5) years.

[9] Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process.

Resource Alternatives	Term	Location	Requirements
			EPC specifications in **Attachment 17**; and contractual privities between PacifiCorp and the EPC contractor. Bidder must complete **Appendix C-2 and Attachment 19.**
4) APSAs on Bidder's Site	Life of the asset will be evaluated consistent with 2011 IRP Tables 6.1-6-4.[10] Coal resources, limited to a Maximum Term of less than 5 years, are not eligible for this Resource Alternative.	Facility built on a Bidder's site which is a new facility. If it is an existing facility, it should be bid under #5.	Bid pursuant to the APSA; PacifiCorp will own and operate the facility following commercial operation. Bidder must complete **Appendices C-2** and **F and Attachment 19**. Contractual privities between PacifiCorp and the EPC contractor. Company will perform due diligence of Bidder technical specification or Bidder may be required to apply Company technical specifications in

[10] Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process.

Resource Alternatives	Term	Location	Requirements
			Attachment 17.
5) Purchase of an existing facility	Evaluation will be completed based on the remaining depreciated life of the asset. Life of the asset will be determined by the 2011 IRP Tables 6.1-6.4 [11] Coal resources are eligible for this Resource Alternative if the remaining Life of the asset is limited to a Maximum Term of less than 5 years.	A single resource located in or delivering to PACE or PACW and integrated as a Network Resource.	Due diligence of facility that PacifiCorp deems appropriate (see **Attachment 13**). Bidder must complete **Appendix C-3 and Attachment 19.** PacifiCorp would own and operate the facility.
6) Purchase of a portion of a facility jointly owned by and/or operated by PacifiCorp	Same as #5	Same as #5	Same as #5
7) Restructuring of Existing PPA or Exchange Agreement and/or Buyback of an Existing Sales Agreement	Fixed term specified in the bid up to the life of the PPA or Exchange Agreement must be a minimum of 5 years and 100 MW. A PPA or Exchange Agreement for a coal resource is limited to a Maximum Term of less than 5 years, and a minimum of 100	Same as #5	Restructuring of the PPA or Exchange Agreement and/or buyback of an existing sales agreement must result in incremental capacity and energy. Bidders must complete

[11] Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process.

Resource Alternatives	Term	Location	Requirements
	MW.		**Attachment 19.**
Exceptions			
8 (a) Load Curtailment	Fixed term must be a minimum of 5 years and 25 MW.	Existing end use PacifiCorp customers with a load that can be physically curtailed and must be not less than 25 MW. The 25 MW may be aggregated. The load must respond within 30 minutes prior to the hour and remain curtailed for one continuous hour blocks.	PacifiCorp will not accept proposals for financial curtailment nor will it accept proposals that result in PacifiCorp having a residual delivery obligation for the curtailment of load via any other contract, law, regulation or order. Bidders must complete **Attachment 19.**
8 (b) Qualifying Facility (QF)	Fixed term must be a minimum of 5 years and 10 MW.	Same as #5	QFs are as defined under the regulations implementing the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Bidder must complete **Attachment 2, 19** and **Appendices C-1** and **F.**
8 (c) Eligible Renewable	Fixed term must be a minimum of 5 years and 10 MW. A PPA	Same as #5	Company must be able to dispatch or schedule renewable

Resource Alternatives	Term	Location	Requirements
Resource	not backed by assets is limited to a Maximum Term of 5 years and a minimum of 10 MW.		resource. Bidder must complete Bidders must complete **Attachment 19 and Appendices C-1, D, and F.**

1. PPA

Power purchase bids must be for a fixed term at a stated price which may be indexed to CPI, GDP, or a fixed annual rate specified by the Bidder. PPAs can be from a single resource or resources, as applicable, must be located in or into PACE or PACW and must be in the form of a PPA. A PPA Pro Forma Agreement is attached as **Attachment 3**. The source of energy and capacity for the PPA should be (a) a generation facility located on a Bidder-supplied site, or (b) from the Bidder's electrical system. The fuel source type must be specified in the proposal. Bids, including those from new or existing coal resources will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

In the event a Bidder proposes a PPA not backed by assets, the term accepted will be limited to a Maximum Term[12] of less than five (5) years.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor under a single EPC contract or an equivalent structure which will not increase the risk of default by multiple contractors to the Company and its customers. Any Contractor must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity (or its credit support provider) must have a Credit Rating[13] that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp. (See Appendix B)

[12] Maximum Term of five (5) years means a term of greater than one (1) year but no more than five (5) years.

[13] Credit Rating is defined in Section H.1.

2. TSA

Tolling Service Agreement bids must be for a fixed term at a stated price which may be indexed to CPI, GDP, or a fixed annual rate specified by the Bidder. TSAs can be from a single resource which is located in or delivering to PACE or PACW, and must be in the form of a TSA. The fuel source type must be specified in the proposal. A Pro Forma TSA is attached as **Attachment 5**. The facility from which the TSA is bid can be located on (a) a Bidder-supplied site, or (b) from the Bidder's electrical system. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. Bids, will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

In the event a Bidder proposes a TSA not backed by assets, the term accepted will be limited to a maximum of less than five (5) years.

The Bidder must specify in its bid whether the TSA will take the form of a financially settled physical TSA or physical TSA, if applicable. If the TSA is (1) a financially settled physical tolling arrangement, the Bidder will be responsible for the fuel, transportation, fuel-related O&M, and start-up charges, if any, or (2) a physical tolling arrangement, the Company may elect to be responsible for the fuel and transportation, however, the Bidder must demonstrate that fuel and transportation are available.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor under a single EPC contract or an equivalent structure which will not increase the risk of default by multiple contractors to the Company and its customers. Any Contractor must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity (or its credit support provider) must have a Credit Rating that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp.(See Appendix B)

3. EPC/APSA on PacifiCorp Defined Site

Bids for construction on a PacifiCorp defined site must take the form of the EPC Pro Forma Agreement to which the Company and the entity with overall EPC responsibility for the project must be parties. The EPC Pro Forma Agreement and the APSA Agreement are attached as **Attachment 4 and Attachment 6, respectively** and **Attachment 17** which sets forth the PacifiCorp site specifications. The fuel source type must be specified in the proposal. Any EPC and/or APSA proposal for the facility at the Currant Creek site must be bid in compliance with the specifications in **Attachment 17**. All Bidders in this category must complete the information requested in **Appendix C-2** and all submission documents identified in **Attachments 4 and 17**.

If the Bidder is submitting an EPC, the Bidder shall be responsible for the engineering, procurement and construction of the facility, including, but not limited to, construction permitting, engineering, procurement, and all related costs up to achieving commercial operation, with the exception of those costs to be borne by the Company to support start-up, testing, commissioning, and acceptance that are explicitly defined in the Bidder's proposal. If a bidder builds a project at the Currant Creek site the project must be built to meet the specifications provided in **Attachment 17**. Design evaluation criteria that the Company will use for bid screening and evaluation purposes can be located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP. Attachment 1 further provides information regarding the EPC Resource Alternative. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. If the Bidder is submitting an APSA the Bidder shall be responsible for all of the EPC requirements described above as well and the development of the project.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor, which must be a party to the EPC and or the APSA. To the extent the Bidder uses a Contractor or a separate legal entity other than the Bidder itself, this entity must be a party to the EPC and or the APSA and must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity (or its credit support provider) must have a Credit Rating that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp.(See Appendix B)

The aggregate of the "all-in" capital cost for the EPC and or APSA resource will include all payments to be made to the Bidder under the EPC and or APSA structures. These costs will include all Owners' Costs Under and EPC Owner's Development costs, which will be locked down prior to the receipt of the proposals and are outlined in **Attachments 7 & 8,** respectively. A listing of those categories and costs are in **Attachments 7 & 8.** .

4. APSA on a Bidder's Site

Bids for construction on a Bidder-owned site must be in the form of an APSA, to which the Company and the entity building the project must be parties. The APSA Pro Forma Agreement is attached as **Attachment 6**. The fuel source type must be specified in the proposal, and cannot be coal. Pursuant to the APSA, the Company will own and operate the facility following commercial operation. All Bidders in this category must complete the information requested in **Appendices C-2** and **F**. Bidders should also submit a form operations and maintenance ("O&M") agreement based on the terms and conditions set forth in **Attachment 16**.

Pricing for the purchase and sale of the facility can be structured to include progress payments, with defined milestones, or as a single lump sum payment due upon achievement of commercial operation. The Company will in no event make progress payments to a Bidder unless each such payment results in the transfer of a tangible asset or percentage ownership of an asset at the time each payment is made according to a schedule set forth in the associated bid and is acceptable to the Company.

This Resource Alternative is only for facilities that have not reached commercial operation as of the Bid Due Date. In the event the facility being proposed is existing and commercially operable as of the bid response date, then the Bidder should submit a bid pursuant to Resource Alternative #5 (Purchase of an Existing Facility). The Bidder shall be responsible for all aspects of the development and construction of the facility, including, but not limited to, permitting, engineering, procurement, construction and all related costs up to commercial operation with the exception of those costs to be borne by the Company to support start-up, testing, commissioning, and acceptance that shall be explicitly defined in the Bidder's proposal. The Company may require that the project be operated and maintained by Bidder for up to ten (10) years in order to ensure cost effectiveness, availability and reliability of the resources prior to the Company's acceptance of the resource. The parties agree to negotiate an O&M agreement after the bidder is selected from the Final Shortlist to enter into negotiations. Design evaluation criteria that the Company will use for bid screening and evaluation purposes are located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. As part of the Bidder's proposal under this Resource Alternative, the Bidder shall provide a comprehensive design basis and technical specification for the proposed facility.

Bidders should note that any proposal submitted in this category that proposes new construction of a generation facility must utilize the services of a single primary Contractor, which must be a party to the APSA. To the extent the Bidder uses a Contractor or a separate legal entity other than the Bidder itself, this entity must be a party to the APSA and must be experienced with the type of facility being proposed and, in addition to any other credit provision described herein, this entity (or its credit support provider) must have a Credit Rating that is BBB-/Baa3 or greater from S&P/Moody's or, if not publicly rated, an equivalent Credit Rating as determined by PacifiCorp. (See Appendix B)

The Company will own and the Bidder may be required to operate the facility following commercial operation for up to ten (10) years. Any existing power supply obligations (if any) associated with the facility shall not be assigned to the Company unless the Company, in its sole discretion, accepts such assignment.

The aggregate of the "all-in" capital cost for the APSA resource shall include all payments to be made to the Bidder under the APSA.

5. Purchase of an Existing Facility

In the event a sale of an existing facility is proposed by a Bidder, and if the facility is interconnected to PACE or PACW and commercially operable as of the bid response date, the Company will consider purchasing, owning, and operating the facility. The fuel source type must be specified in the proposal. Any such purchase would be contingent on disclosure to the Company by the Bidder of all information regarding the facility that may be material to the Company's decision to make the purchase, including without limitation all potential or existing claims or liabilities, on the Company's completion of and satisfaction with the results of such due diligence inquiries that the Company may deem appropriate in its sole discretion, and on the transfer of good and marketable title to the Company by the Bidder, free and clear of any and all liens and encumbrances. Such inquiries may include, but will not be limited to, site inspections, interviews, audit of all applicable books, contracts, forecasts, and records, and/or an assessment of past, future, or potential environmental liabilities. In addition, any existing network or point-to-point transmission rights associated with the facility's output must be released and reassigned to the Company, at the Company's option.

Such due diligence will be performed by qualified generation experts, who may be third-party legal and environmental experts and consultants satisfactory to the Company in its sole discretion, in addition to Company personnel. The Company reserves the right to no longer consider the resource, if in its sole discretion; it determines that there are aspects of the resource not in the best interest of the Company and its customers. The Company will require the information outlined in **Appendix C-3** to be provided by the Bidder in order to determine if the asset will be evaluated and the priorities of the evaluation. Design evaluation criteria that the Company will use for bid screening and evaluation purposes are located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. Bids will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

Existing power supply obligations associated with the facility, if any, shall not be assigned to the Company unless the Company, in its sole discretion, accepts such assignment.

6. Purchase of a Portion of a Facility Jointly Owned and/or Operated by PacifiCorp

A Bidder may propose that the Company purchase all or an additional portion of a facility in which the Company already has an existing ownership interest or one that the Company currently operates. The fuel source type must be specified in the proposal. Any such purchase by the Company would be contingent upon disclosure to the Company by the Bidder of all information regarding the facility and the Bidder's interest that may be material to the Company's decision to make the purchase, including without limitation, potential or existing claims or liabilities, the Company's completion of and satisfaction with the results of such due diligence inquiries that the Company may deem appropriate in its sole discretion; and the transfer of good and marketable title to the Company by the Bidder of the Bidder's interest, free and clear of any and all liens, claims and encumbrances. The Company's due diligence inquiries may include, but will not be limited to, an audit of all applicable books and records, and/or an assessment of past, future, or potential environmental liabilities. In addition, any existing network or point-to-point firm transmission rights associated with the facility's output owned or controlled by the Bidder must be released and reassigned to the Company, at the Company's option.

Such due diligence will be performed by qualified generation experts, which may be third-party legal and environmental experts and consultants, in addition to Company personnel. The Company reserves the right to no longer consider the resource, if in its sole discretion it determines that there are aspects of the resource that are not in the best interests of the Company and/or its customers. The Company will require the information outlined in **Appendix C-3** to be provided by the Bidder, in order to determine if the asset will be evaluated and the priorities of the evaluation. Design evaluation criteria that the Company will use for bid screening and evaluation purpose is located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. Bids will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

The Company would own and operate the prospective facility following closing on the sale. Existing fuel commodity or power commodity obligations associated with the facility, if any, shall not be assigned to the Company unless the Company, in its sole discretion, accepts such assignment.

7. Restructure of an Existing PPA or an Exchange Agreement and/or Buyback of an Existing Sales Agreement

The Company will accept proposals under this Resource Alternative for one or more of the following: (a) restructuring of an existing PPA between the Company and the Bidder; (b) an Exchange Agreement between the Company and the Bidder; and (c) the termination or buyback of an existing agreement for the sale of energy and capacity by the Company to the Bidder in PACE or PACW.

The fuel source type must be specified in the proposal.

If the bid calls for the restructuring of an existing PPA between the Company and the Bidder, such restructuring must result in making available to the Company incremental dependable energy and capacity in an amount of not less than 100 MW within PACE or PACW during the summer season (July through September) for delivery as provided in this RFP for a minimum term of five (5) years. The Bidder will be required to assign any and all existing network or point-to-point firm transmission rights associated with the incremental energy and capacity to the Company at the Company's request at no additional cost if the Company selects this bid. Bids will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

If the bid calls for an exchange agreement, such agreement would provide for the delivery by the Bidder to the Company of dependable energy and capacity in an amount of not less than 100 MW for delivery of a minimum of a five (5) year term as described in this RFP, in exchange for power to be supplied by the Company to the Bidder at another location (other than PACE or PACW) and/or during another time period.

8. Resource Alternative Exceptions

The following resources qualify for one of the three exceptions set forth below:

a. Load Curtailment

The Company has found that bilateral agreements with large end-use customers for the physical curtailment of load have proven to be effective in reducing the need for incremental energy and capacity at critical times. The fuel source type must be specified in the proposal. The Company invites end-use customers to bid physical load curtailment under this RFP. Any such bid must meet the following requirements: (a) the Bidder must be an existing end-use customer of the Company; (b) the load to be curtailed must be not less than 25 MW, however load can be aggregated by a single supplier to equal a total of 25 MW or more; (c) the curtailment must be a physical curtailment of the load; (d) the load to be curtailed must respond to the curtailment order 30 minutes prior to the hour within and remain curtailed for continuous one-hour blocks; (e) the Company must not have any residual delivery obligation for the curtailed load after exercising its curtailment rights hereunder pursuant to any other contract, law, regulation or order, and Bidder must waive any and all rights to assert any such contrary rights; and (f) the Bidder must provide the Company with reasonable contractual surety and credit assurances that such load curtailment will take place at times and in amounts required by this RFP. The Company will not accept proposals for financial curtailment of load. Bidders should start with the PPA (**Attachment 3**) as the underlying agreement.

b. Qualified Facility

QFs, as defined under the regulations implementing PURPA, with 10 MW or greater of capacity are eligible to participate in this RFP. Firm QFs with 10 MW or greater of capacity and a minimum term of five (5) years or longer will constitute a Resource Alternative exception. Design evaluation criteria that the Company will use for bid screening and evaluation purposes are located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP. Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements which will be considered by the Company in consultation with the IEs during the bid evaluation process. The fuel source type must be specified in the proposal. All Bidders in this category must complete the information requested in **Appendices C-1**, and F. Each QF Bidder must also submit the required information in **Attachment 2**[14] in order to be evaluated under this RFP. QF Bidders are subject to the credit requirements contained in this RFP. Bidders should start with the PPA (**Attachment 3**) as the underlying agreement. Bids will be considered by the Company and, during the evaluation process, will be given appropriate weight based on carbon ("CO_2") risks and other environmental compliance costs and risks associated therewith.

c. Eligible Renewable Resources

If the Bidder proposes an Eligible Renewable Resource, such proposal must provide for the delivery by the Bidder to the Company of dependable energy and capacity in an amount of not less than 10 MW for a minimum term of five (5) years as described in this RFP. However, in the event a Bidder proposes a PPA not backed by assets, the maximum term accepted will be five (5) years. The source of energy and capacity for the PPA should be a generation facility located on a Bidder-supplied site. Design evaluation criteria that the Company will use for bid screening and evaluation purposes is located in Chapter 6: Resource Options (Tables 6.1-6.4) of the 2011 IRP Bidders may propose adjustments to the Design Plant Life based on existing or planned plant improvements

[14] Schedule 38 in Utah and Oregon are included. Depending on location of the resource, a Bidder may also need to comply with the state specific QF tariff schedules which are available on PacifiCorp's website at: http://www.pacificorp.com/es/cg/cqfp.html

which will be considered by the Company in consultation with the IEs during the bid evaluation process. The fuel source type must be specified in the proposal. The Bidder should assume that the Company will not own or operate any facility bid into this category. All Bidders in this category must complete the information requested in **Appendices C-1, D,** and **F.** Bidders should start with the Power Purchase Agreement (**Attachment 3**) as the underlying agreement. Bidders are subject to the credit requirements contained in this RFP. Geothermal resources are encouraged to bid.

BID FEES/ PROPOSAL OPTIONS

To help defray the cost of the IEs, each Bidder shall submit with each of its bid proposals a nonrefundable "bid fee" of $10,000. Bidders submitting a bid in Resource Alternative category #8 (load curtailment, QFs, and Eligible Renewable Resources) shall submit a nonrefundable bid fee of $1,000. A bid in each Resource Alternative category may consist of one base proposal in addition to two alternatives for the same bid fee. The alternatives may consist of a different bid size, contract term, pollution control technologies, water cooling technologies, in-service date and/or pricing structure for the same Resource Alternative and Bid Category. In addition, bidders will have the option of submitting up to five additional alternatives as follows: (i) the fourth through sixth additional alternatives at a fee of $1,000 each, (ii) the seventh additional alternative at a fee of $2,000 and (iii) the eighth additional alternative at a fee of $3,000. A proposal for a different Resource Alternative, a different Bid Category, at a different site or using a different technology will be considered a separate proposal and will be subject to a separate bid fee. All bid fee(s) must be submitted with the proposals that are sent to Boston Pacific. The Bidder must attach to its proposal a certified check written in the required amount payable to the order of PacifiCorp. Bidders may submit multiple base bid proposals in response to this RFP. The IEs, in consultation with the Company shall confirm whether a Bidder's submission constitutes one or more proposals, for purposes of assessing bid fees. Any questions regarding bid fees should be directed to Merrimack Energy Group, Inc. or Boston Pacific.

PacifiCorp is interested in creative proposal options that add value to customers however, if a proposal is contingent on another proposal the Bidder must clearly state any contingencies so that the Company can evaluate them accordingly. As a result, PacifiCorp encourages Bidders to offer several different alternatives under the same proposal. For each proposal, Bidders are allowed to submit a base proposal and up to two alternatives, for the same bid fee. Bidders will also be allowed to offer additional alternatives as follows: (i) the fourth through sixth additional alternatives at a fee of $1,000 each, (ii) the seventh additional alternative at a fee of $2,000 and (iii) the eighth additional alternative at a fee of $3,000. Alternatives will be limited to different bid capacities, contract terms, cooling technologies, in-service dates,[15] and/or pricing/security structures. A Bidder may submit more than one proposal. If a Bidder submits the same

[15] Alternate in-service dates must comply with the guidelines set out in this RFP.

proposal but with three different bid capacities, the proposal must be considered one proposal with two alternatives and the Bidder will pay one bid fee. The Company's objective in offering Bidders the opportunity to propose multiple alternatives is to allow the Company to optimize the benefits from the solicitation by combining proposals of different capacities, terms and in-service dates.

FLEXIBILITY OF PROPOSALS

PacifiCorp is interested in proposals which offer PacifiCorp flexibility in terms of the commencement date of delivery in the contract and which provide PacifiCorp the ability to defer or accelerate the in-service date of the contract or buy-out the contract at its option. The Company will only allow Bidders to defer or accelerate in-service dates as an option that can be exercised by the Company. Proposals for firm online dates beyond June 1, 2016 are not allowed; however, Bidders can request approval with the IE to submit proposals having firm online dates prior to June 1, 2016. If Bidders provide proposals which would include an option to extend the proposal beyond the original term, Bidders are required to specifically identify such option and the required terms, conditions and price upon which the Company would exercise such option. If the Bidder is not offering to extend the term and no such option language is included in the proposal, the Company will not assume that the Resource Alternative extends beyond the term provided by the Bidder. Bidders are encouraged to be creative in their proposals within the scope of the RFP. To the extent Bidders want to propose in-service date deferral or acceleration options, Bidders should provide a complete description of their proposed deferral or acceleration option as an attachment to **Form 2**. Bidders should provide a schedule that offers a one (1) year in-service date deferral option and a one-year acceleration option along with the strike price (in total dollars) for which PacifiCorp would compensate the Bidder for exercising the option at each milestone date identified in **Form 2**. The schedule should also include the milestone dates prior to the proposed in-service date at which PacifiCorp could decide to exercise the deferral or acceleration option. Bidders can also offer a price schedule associated with the option for PacifiCorp to buy-out the contract at different milestone dates prior to commercial operation. For the buyout option, Bidders should use **Form 2** as a component of their bids. Bidders can provide breakup fees for all the milestone dates listed in **Form 2**, or identify select milestones and submit breakup fees for those dates. The milestones may be modified by the Bidders to address the specific project and proposal. For each option, Bidders should identify the option proposed along with specific triggers (i.e., triggers associated with specific milestones) within the Bidder's proposal. Concerning deferral, acceleration, and breakup options, Bidders must complete **Form 2** with suggested milestones and strike price. For each resource and alternative proposed, **Forms 1** and **2** should be completed, if applicable.

UNACCEPTABLE PROPOSAL CHARACTERISTICS

The Company will not accept renewable resources that cannot be dispatched or scheduled by PacifiCorp. All bids from new or existing coal resources will be considered by the Company and, during the evaluation process, will be given appropriate weight based on CO2 risks associated therewith.

The Company will not accept proposals where the Bidder retains the option to displace any resource for economic reasons and/or where the Bidder holds the unilateral option to select one or more alternate Point(s) of Delivery. In addition, the Company will not accept any proposal that provides for planned maintenance or planned derates per the North American Electric Reliability Corporation ("NERC") during the months of June through September or December through February in any year.

SECTION 3. LOGISTICS

A. SCHEDULE OF RFP ACTIONS

Table 2 sets forth the anticipated schedule:

Table 2

Event	Anticipated Date
RFP issued	January 5, 2012
RFP bid conference	January 17, 2012
Intent to Bid Forms due	February 14, 2012
Bidders submit proposals (Bid Due Date)	May 9, 2012
Evaluation of Initial Shortlist completed	July 8, 2012
Only Initial Shortlist submits best and final updated proposals (Best and Final Bid Due Date)	August 8, 2012
Final evaluation of Best and Final Bids completed Final Shortlist	September 10, 2012
Oregon Commission acknowledgement of Final Shortlist[1]	October 2012
Negotiation of bids on Final Shortlist completed	December 22, 2012
PacifiCorp decision	January 7, 2013
File application in Utah Commission approval proceeding (120 days)	January 16, 2013
Utah Commission approval (120 days) from filing	May 16, 2013
Avoided cost filing[2]	
[1]The Oregon Commission may acknowledge the Final Shortlist. *See* Oregon Order No. 06-446 Guideline 13.	
[2]Updated avoided costs filing by state will be made to the extent required by law or regulatory order.	

<u>Bidders should note that the above schedule is an anticipated schedule only and is subject to change. The Company accepts no liability to the extent the actual schedule is different from the anticipated schedule.</u>

B. PREBID CONFERENCE

Time:	9:30 -10:30 a.m. Pacific Time / 10:30 -11:30am Mountain Time
Date:	January 17, 2012
Location:	Oregon - 825 NE Multnomah – Room 956 (9th floor) Utah - North Temple Office – 215 L (2nd Floor above Security desk)

Interested parties and Bidders may submit questions prior to the RFP bid conference. All information, including the pre-bid conference materials, questions and answers will be posted on the PacifiCorp website at www.pacificorp.com prior to the issuance of the final approved RFP. After the final approval of the RFP, Merrimack Energy Group, Inc. will be responsible to maintain and post all materials on a website established by the IE. The Company will be responsible to maintain and post all materials on the Company's website at www.pacificorp.com. Any questions on the RFP or related documents and all communications with the Oregon and Utah IEs should be directed as follows:

Utah Independent Evaluator: Merrimack Energy Group, Inc.
http://www.merrimackenergy.com/PacifiCorp2008RFP/index.asp
Oregon Independent Evaluators: Boston Pacific Company, Inc.
croach@bostonpacific.com

C. INTENT TO BID FORMS

Bidders who intend to be considered as part of this RFP process **<u>must</u>** return the "Intent to Bid Form" **(Appendices A and B)** as set forth below. Two (2) copies of the Intent to Bid Form must be sent to <u>both</u> of the following addresses by express, certified or registered mail, or hand delivery by 5:00 p.m. Pacific Time on February 14, 2012.

Utah Independent Evaluator
Merrimack Energy Group, Inc.
c/o Utah Division of Public Utilities
Heber M Wells Bldg, 4th Floor
160 East 300 South
Box 146751
Salt Lake City, Utah 84114-6751

<u>and</u>

Oregon Independent Evaluator
Boston Pacific Company, Inc.
c/o Pacific Power Legal Department
Attention: Mary Wiencke
825 NE Multnomah, Suite 1800
Portland, Oregon 97232

D. SUBMISSION OF BIDS

Bidders are required to submit hard copies and electronic copies of proposal(s) as set forth below:

1. a signed original and two (2) hard copies of each bid and any required forms, and
2. two (2) electronic copies of the bid and any required forms (on two (2) separate compact discs) that are in PDF format.

Utah Independent Evaluator
Merrimack Energy Group, Inc.
c/o Utah Division of Public Utilities
Heber M Wells Bldg, 4th Floor
160 East 300 South
Box 146751
Salt Lake City, Utah 84114-6751

and

Oregon Independent Evaluator
Boston Pacific Company Inc.
c/o Pacific Power Legal Department
Attention: Mary Wiencke
825 NE Multnomah, Suite 1800
Portland, Oregon 97232

Bids will be accepted until 5:00 p.m. Pacific Time on May 9 , 2012 Any bids received after this time will be subject to return unopened to the Bidder following a decision based on consultation between the IEs and PacifiCorp.

Only Bidders on the Initial Shortlist will be required to submit updated Best and Final proposals to the addresses above by 5:00 pm Pacific Time on **August 8, 2012** . Any bids received after this time will be subject to return unopened to the Bidder following a decision based on consultation between the IEs and PacifiCorp.

E. RFP TEAM

An RFP Team will be established by the Company prior to the final approval of the RFP. The RFP Team shall consist of an Evaluation Team and Intent to Bid Team. The composition of the teams and their primary roles and responsibilities are shown below in Chart 3.

CHART 3

Work Group	Roles
IEs	The IEs will ensure a fair and reasonable process is used in the RFP. The IEs will provide oversight of the RFP process and will validate, audit and review all aspects of all proposals, providing oversight to the process and validation on the models, inputs, assumption(s), risk assessment, and generation specifications for the PacifiCorp sites. See **Attachment 18** for Role of the IEs.
Evaluation Team: Origination, Generation, and/or Third-Party Engineering Consultants as required	Overall coordinator of the process. Bid process management for all proposals and coordination with the IEs and all of the work groups. Evaluation of the non-price components of the analysis. Specifying, evaluating and confirming conformity with design specifications; conducting, as needed, technological and operational due diligence, generation expertise, environmental due diligence on all resources.
Evaluation Team: Structuring and Pricing, Integrated Resource Planning Team, Generation and/or Third-Party Engineering Consultant as required.	Economic analysis and modeling including validation of the inputs to the risk assessment of the bid.
Evaluation Team: Environmental	Air, water and discharge, emission credits, site permits and facilities.
Evaluation Team: Credit	Credit screening, evaluation and monitoring throughout the process.
Evaluation Team: Legal	Legal will confirm compliance of bids to requirements of RFP and its Forms, Attachments and Appendices; conduct of legal process; conducting due diligence inquiries; supervising any documentation entered into as part of the RFP process.
Intent to Bid Team: Origination, Generation, Legal and Credit	Origination, Generation, Legal and Credit will work with the IEs to ensure that Appendices A and B are complete.

F. EFFECTIVENESS OF BIDS

Each bid proposal must remain open for acceptance by the Company from the date of submittal through **June 15, 2013** unless earlier released in writing by the Company or if the Bidder's proposal does not make the Final Shortlist. If during the course of the RFP process, the Company, with input from the IEs, determines that a Bid update is appropriate, then all Bidders will be entitled to update their assumptions.

G. PROCEDURAL ITEMS

1. Intent to Bid Form - Bidder's Qualification, Capability and Credit

In order to participate in the RFP, each Bidder must complete and submit to the IEs the Intent to Bid Form which includes **Appendices A** and **B** for each Resource Alternative it intends to submit in its proposal by the date identified in Section 3. The Company will require each Bidder to demonstrate its Qualification Capability and Experience as required in **Appendix A**. In addition, twenty (20) business days after the Bidder is notified by the Company that the Bidder has been selected for the Final Shortlist the Bidder will be required to provide any necessary guaranty commitment letter from the entity providing guaranty credit assurances on behalf of the Bidder and/or necessary letter of credit commitment letter from the financial institution providing letter of credit assurances. The timing of when credit security must be posted is detailed in **Attachment 14**. The forms of commitment letters are in **Attachment 15.**

Attachment 14 explains how the Credit Matrix in **Appendix B** will be used to determine the amount of credit assurances required if a Bidder makes the Final Shortlist. The use of the Credit Matrix requires a sequence of checks against the Credit Matrix. The Bidder must first check its Credit Rating in the Credit Matrix in order to determine the amount of credit assurances required. If the amount of credit assurances required from the prior sentence is an amount other than $0, the Bidder must next check the Credit Rating of its proposed credit support provider in the Credit Matrix. The difference in the amounts of credit assurances required using the Bidder's Credit Rating and amount of credit assurances required using its proposed credit support provider's Credit Rating is the maximum amount that the credit support provider will be required to commit to in its commitment letter. For any residual amount of credit assurances required, the Bidder must obtain a commitment letter from a second credit support provider with a higher Credit Rating than the first credit support provider, committing to provide credit assurances in the residual amount. Note that the higher Credit Rating of any second credit support provider will need to be high enough such that any ultimate residual amount will be $0. An example of using the Credit Matrix in this sequence of checks is described in **Attachment 14**. It is important that Bidders realize that more than one commitment letter from the entity(ies) providing credit assurances on behalf of the Bidder may be required and if the Bidder is selected further credit requirements will be required as it pertains to the specific credit requirements in each of Agreements in **Attachment 1,3,4,5,** and **6**. If the Bidder's initial proposed credit support provider's Credit Rating is high enough such that the amount of credit assurance required is $0, note that only a single commitment letter from that entity is needed, and the amount required will be the difference between what is required based on the Bidders Credit Rating and $0.

Appendices A and **B** are attached to the Intent to Bid Form and must be completed in order to submit a proposal. In **Appendix A**, the Bidder must provide information that the Bidder's project development team has successfully completed the development and commissioning of at least one generation project with characteristics similar to the proposed project. The proposal must pose an acceptable level of development and technology experience, as determined by the Company's Evaluation Team. In **Appendix B** the Bidder must demonstrate the ability to post the credit assurances consistent with the Credit Matrix for each Resource Alternative being proposed if they are selected on the Final Shortlist. Each Bidder must provide the requested financial and credit information and indicate what its ability will be to post any necessary credit assurances, if applicable, and be prepared to provide the necessary guaranty and/or letter of credit commitment letter(s) if it is selected for the final short list. The forms of commitment letters are in **Attachment 15**.

All Bidders must demonstrate their ability to meet the credit requirements and to provide any necessary credit assurances, including their plan for doing so (including the type of security proposed, sources of security and a description of its credit support provider) for the Resource Alternative they are proposing. Bidders should also provide a demonstration of their ability to finance their project based on past experience and a sound financial plan identifying the proposed sources for debt and equity. If the Bidder does not provide all the information required in **Appendices A** and **B** to the satisfaction of the Company the Bidder may be notified that the Bidder will not be eligible to submit a proposal. If the Bidder can demonstrate to the Company its ability to meet the qualifications in **Appendices A** and **B** then the Bidder will be permitted to submit proposal(s) in the RFP. In the event that the Bidder (or Bidder's credit support provider's) credit status changes at any time after submission of a bid into the RFP process, the Company reserves the right to request updated information to reevaluate the creditworthiness of the Bidder and/or the Bidder's credit support provider.

The Bidder will be required to demonstrate its ability to post credit assurances in the amounts outlined in the Credit Matrix in **Appendix B** or as otherwise adjusted based on the Bid Category proposed. A credit methodology paper explaining the rationale behind the Credit Matrix is provided in **Attachment 14.** A Bidder must be able to demonstrate its ability to post any necessary credit assurances in the form of a guaranty commitment letter from either a proposed guarantor and/or in the form of a letter of credit commitment letter from a financial institution that would be issuing a letter of credit. This commitment letter(s) is then to be posted twenty (20) business days after the Bidder is selected for the Final Shortlist. Forms of credit commitment letters are provided in **Attachment 15**. The amount of any credit assurances to be provided will be determined based upon (a) the Credit Rating in the Credit Matrix of the Bidder and the entity(ies) providing credit assurances on behalf of the Bidder, if applicable, (b) the size of the project, (c) the Eligible Online Date, (d) the type of Resource Alternative bid, and (e) the Bid Category proposed. Please note that a financial institution providing credit assurances on behalf of the Bidder must have a Credit rating of a least 'A' and 'A2' from Standard & Poor's Rating Group (S&P) and Moody's Investors Services, (Moody's), respectively, and have assets (net of reserves) of at least $10,000,000,000. QF Bidders and Eligible Renewable Resource Bidders are subject to the credit requirements contained in this RFP.

The Credit Rating is defined as the lower of: (x) the most recently published senior, unsecured long-term debt rating (or corporate rating if a debt rating is not available) from S&P or (y) the most recently published senior, unsecured debt rating (or corporate rating if a debt rating is not available) from Moody's. If option (x) and (y) are not available, the Credit Rating will be determined by the Company through an internal process review and utilizing a proprietary credit scoring model developed in conjunction with a third party. All Bidders will receive a Credit Rating which will determine the amount of any credit assurances to be posted.

If a Bidder is an existing counterparty of the Company, the Company reserves the right to protect itself from counterparty credit concentration risk and may require credit assurance in addition to that outlined in the credit matrix.

In addition to any credit security requirements as shown in the Credit Matrix, the Bidder may be required to post other credit security, depending on the Resource Alternative that is bid. The bidder should refer to the respective proforma agreement for that Resource Alternative for any additional credit security requirements.

In the event that the Bidder posts a letter of credit as collateral it must be issued by a bank acceptable to the Company in the Company's reasonable discretion, and be in form and substance acceptable to the Company and meet the requirements set forth in **Attachment 9.** The timing of when credit assurances must be posted is detailed in **Attachment 14.**

2. Submission of Proposals by Bidders

All bid proposals must be received no later than the date specified in Section 3. All bid proposals must contain the requirements and be in the format set forth in the RFP Proposal Form for the specific Resource Alternative as indicated in Section 4. The RFP Proposal Form identifies all of the required Attachments and Forms for each Resource Alternative the Bidder intends to submit. Any bid proposal that does not contain <u>all</u> of the required information by the due date specified in Section 3 will be subject to rejection as nonresponsive following review and agreement by the IEs and the Company. It is each Bidder's responsibility to submit additional information related to its bid proposal if such information will materially improve the value of its bid proposal or the Company's understanding thereof.

Each bid proposal must be signed by an officer of the bidding company via an Officer Certification found in **Appendix E.** Each proposal must contain the following information:

a) Each bid must include a statement by the Bidder that the Terms and Conditions of the applicable Pro Forma Agreements, selected as part of the Resource Alternatives submitted by Bidder, are acceptable to the Bidder **or** identify any significant exceptions to the Pro Forma Agreements in the form of a redline agreement or through written comments which specifically identify the significant exceptions as part of the Bidder's proposal.

b) Proposals must clearly specify all pricing terms. In addition, Bidders should describe any contract deferral and acceleration options proposed, as well as any contract buyout options proposed. Proposals with pricing that is subject to change must explain what triggers the change, what the change is tied to, and any information the Company will require to evaluate the pricing risks associated with the proposal. All pricing must be in terms of nominal dollars. Prices and dollar figures quoted will be assumed to be in nominal terms for the year in which they occur unless clearly stated otherwise. The Form Pricing Input Sheet (**Form 1**) contains the applicable pricing inputs which will be required to be completed by the Bidder for the bid to be evaluated. This Form Pricing Input Sheet includes inputs such as start/end date, point of interconnection, resource type, variable and fixed O&M, start-up costs, capacity payment or capital expenditures, PPA or TSA escalation rates, heat rates and capacity levels adjusted for both expected temperature, degradation per the manufacturer's recommended maintenance schedule, and a variety of other inputs, including specific published indices, if applicable.

c) All bid proposals must be for a capacity greater than 100 MW except for: (i) QF or Eligible Renewable Resources which must have 10 MW or greater of installed capacity; and (ii) end-use customers or an aggregate of the Company's customers with physical load curtailment proposals for a minimum of 25 MW each.

d) Bid proposal prices must clearly define all costs that the Bidder expects the Company to pay associated with any of the Resource Alternatives, including, but not limited to, station service, test energy, fuel for testing, gas lateral construction, electrical interconnection, other utilities interconnection costs, start-up consumables, or any other costs (including fuel) the bidder expects the Company to incur to accomplish synchronization and/or project turnover.

e) All bid proposals must indicate a present ability and commitment to abide by environmental, health, and safety standards, no less stringent than PacifiCorp's standards, with respect to the operation, construction and maintenance of any physical resources, facilities, plant or equipment.

f) All bid proposals must provide evidence that the developer or the Bidder has already obtained or will obtain the generation site (e.g. letter of intent) before signing a contract with the Company.

3. Minimum Eligibility Requirements for Bidders

Bidders may be disqualified for failure to comply with the RFP if any of the requirements are not met. To the extent proposals do not comply with these requirements they will be deemed ineligible and will not be considered for further evaluation. PacifiCorp, in consultation with the IEs, will return those proposals deemed ineligible together with the bid evaluation fee. Reasons for rejection of a Bidder or its bid include:

a) Receipt of proposal and/or Intent to Bid Form after the applicable response deadline.

b) Failure to meet the requirements and provide all of the information requested in Section 4 of the RFP, including provision of the content required for each Resource Alternative.

c) Failure to permit disclosure of information contained in the proposal to PacifiCorp's agents, contractors or regulators.

d) Any attempt to influence PacifiCorp or the IEs in the evaluation of the proposals, outside the solicitation process.

e) Failure to disclose the real parties of interest in the proposal submitted.

f) Bidder is in current material litigation or has threatened material litigation against PacifiCorp. The Company will work with the IE to determine if the Bidder should be excluded from the RFP in the event the Bidder is threatening or in litigation with the Company.

g) Failure to include a certified check for the appropriate bid fee(s) payable to PacifiCorp.

h) Failure to clearly specify all pricing terms in proposal.

i) Failure to offer unit contingent or system firm capacity and energy, delivered into or in PACW or PACE, including appropriate contract term lengths and commercial operation dates.

j) Presentation of an unacceptable level of development and technology risk.

k) Failure to demonstrate to PacifiCorp's satisfaction that the Bidder's project development team has successfully completed the development and commissioning of at least one generation project with characteristics similar to the proposed project.

l) Failure to demonstrate to PacifiCorp's satisfaction that Bidder can meet the security requirements for each Resource Alternative being proposed consistent with the requirements in the appropriate Pro Forma Agreements for that resource.

m) Failure to address satisfactorily both the price and non-price factors.

n) Bidder's failure to include a statement in the proposal that the Bidder agrees to indemnify and hold harmless the Independent Evaluators for their actions associated with the RFP process.

o) Failure to demonstrate to PacifiCorp's satisfaction the ability to abide by the applicable environmental, health, and safety standards for the project.

p) Failure to submit a contract structure acceptable to PacifiCorp.

q) Bidder or project being bid is involved in bankruptcy proceedings.

r) Submission of a PPA or TSA that is not backed by an asset for a term longer than five (5) years.

4. Company's Reservation of Rights and Disclaimer

The Company reserves the right, without qualification and in its sole discretion, to reject any or all bids, and to terminate this RFP in whole or in part at any time. Without limiting the foregoing, the Company reserves the right to reject as non responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined in Section 4. The Company also reserves the right to request that the IEs contact any Bidder for additional information. The Company further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any Bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact the Company and/or any collusive bidding or other anticompetitive behavior or conduct.

Bidders who submit bid proposals do so without recourse against the Company, its parent company, its affiliates and its subsidiaries, or against any director, officer, employee, agent or representative of any of them and the IE, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. The bid fees submitted by any Bidder, once the bid is accepted, will not be refunded (unless otherwise determined by the Company in consultation with the IEs) in the event of any modification or withdrawal of this RFP, rejection of any bid proposal, or failure to execute an agreement.

5. Accounting

All contracts proposed to be entered into as a result of this RFP will be assessed by the Company for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with any and all information that the Company reasonably requires in order to make such assessments.

Specifically, given the term lengths that PPA, TSA, and/or exchange proposals may cover in response to this RFP, accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a Capital Lease or Operating Lease[16] pursuant to

[16] "Capital Lease" and "Operating Lease" - shall have the meaning as set forth in the FASB ASC Topic 840 as issued and amended from time to time by the Financial Accounting Standards Board.

Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 840 (formerly SFAS No. 13), or (ii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a Variable Interest Entity[17] (VIE) onto PacifiCorp's balance sheet. To the extent a Bidder's proposal results in an applicable contract, the following shall apply with respect to VIE treatment:

> The Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, all Bidders are required to certify, with supporting information sufficient to enable the Company to independently verify such certification, that none of their proposals will subject the Company to such VIE treatment. Bids that result in VIE treatment will be rejected after they are given an opportunity to provide an alternate structure that does not trigger a VIE, which will be subject to consultation with the IEs.
>
> Further, any applicable contract that the Company executes will require that: (i) the Seller covenant that the Company will not be subject to VIE treatment at any point during the term of the agreement, and (ii) in the event that the contract causes the Company to be subject to VIE treatment at any point during the term of the agreement, unless cured, such treatment will constitute a seller event of default.

Each Bidder must also agree to make available at any point in the bid evaluation process, any and all financial data associated with the Bidder, the Facility and/or the PPA, TSA or other contract that PacifiCorp requires to determine potential accounting impacts. Such information may include, but may not be limited to, data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's proposal. Financial data contained in the Bidder's financial statements (e.g., income statements, balance sheets, etc.) may also be required to provide additional information.

To the extent PacifiCorp rejects a proposal submitted in this RFP because it triggers VIE treatment, PacifiCorp shall provide documentation to the IEs justifying the basis for its decision.

6. Cost Associated with Direct or Inferred Debt

PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt (described below) as part of its economic analysis in the initial or Final Shortlist evaluation. However, after completing the Final Shortlist and before the final resource selections are submitted for approval by the Utah Commission, the

[17] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in the FASBASC Topic 810 (formerly FIN 46) as issued and amended from time to time by the FASB.

Company may take into consideration, in seeking approval, cost recovery or acknowledgement with respect to selected resources, any projected costs of direct or inferred debt. Inferred debt will only be considered by the Public Utility Commission of Oregon when the Company seeks cost recovery of selected resources. The Company will bear the burden to demonstrate to the satisfaction of its regulators the validity, magnitude and impacts of any such projected costs. At the request of the Utah or Oregon Commission, PacifiCorp will be required to obtain a written advisory opinion from a rating agency to substantiate the utility's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a Capital Lease pursuant to EITF 01-08 and SFAS No. 13 and the lower of the present value of the nonexecutory minimum lease payments or 100% of the fair market value of the asset must be added to PacifiCorp's balance sheet.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing PacifiCorp's credit standing.

7. Confidentiality

The Company will attempt to maintain the confidentiality of all bids submitted, to the extent allowed by law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the Bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark their entire proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

All information supplied to the Company or generated internally by the Company shall remain the property of the Company. Bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during or after this RFP process unless required by law or regulatory order. The Bidder expressly acknowledges that the Company may retain information submitted by the Bidder in connection with this RFP.

Only those Company employees who are directly involved in this RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or Bidder information.

Bidders should be aware that information supplied by Bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions applicable to that particular proceeding. This means that parties to regulatory proceedings may request to view confidential information. If such a request occurs, the Company will attempt to prevent such confidential Bidder information from being supplied to intervening parties who are Bidders or who may be providing services to a Bidder, but the Company shall not be held liable for any information that it is ordered to be released or that is inadvertently released.

Lastly, the Company intends to utilize its internal, proprietary, forward price projections in its evaluation process. The resulting projections and evaluations will not be shared with entities external to the Company, including with Bidders, unless required by law or regulatory order.

8. Regulatory Process

Utah Code § 54-17-101, *et seq.* requires PacifiCorp to use a solicitation process to construct or acquire a significant energy resource, defined as 100 MW or more with a dependable life of ten (10) years or more. Utah law requires the participation of an independent evaluator, appointed by the Utah Commission, to actively monitor the solicitation process for fairness and compliance with state law. Prior to execution of contracts for any of the Resource Alternatives listed above the Company will go through a preapproval process, consistent with the Utah Energy Resource Procurement Act[18] and will seek acknowledgement of resources pursuant to Oregon Order No. 06-446.[19]

9. Subsequent Regulatory Action

The Company does not intend to include a contractual clause whereby the Company is allowed to adjust contract prices in the event a regulatory agency exercises jurisdiction over the Company, and does not fully recognize the contract prices in determining the Company's revenue requirement. As of the issuance date of this solicitation, PacifiCorp is unaware of any such actual or proposed law or regulatory order.

SECTION 4. RFP PROPOSAL CONTENT

The following outlines the content and format requirements for all proposals by Resource Alternative when responding to this RFP. Proposals that do not include the information requested in this form will be deemed ineligible for further evaluation unless the information is not relevant.

The Bidder is required to provide information in the following format to meet the criteria of this RFP. All sections must be completed and in compliance with the RFP in order for the bid to be accepted. Bidders must provide the appropriate bid fee(s) for the number of Resource Alternatives and Bid Categories that are being offered.

Each Bidder must provide the following information: 1) All RFP Appendices, Form(s)

[18] The Utah Energy Resource Procurement Act may be viewed at: http://www.le.state.ut.us.

[19] Oregon Order No. 06-446 is located at: http://edocs.puc.state.or.us.

and Attachments identified below as required for all proposals; and 2) the Appendices, Form(s) and Attachments identified under each of the Resource Alternatives identified below in Table 4.

TABLE 4

Proposal Type	Required Information
All Bidders are required to submit the following:	Intent to Bid Form: Appendix A and Appendix B Appendix D – Fuel Supply Form (may vary if Bidders offer fixed price) Appendix E – Officer Certificate Form Attachment 19 – Term Sheet of Proposal Form 1 - Pricing Input Sheet Form 2 - Permitting and Construction Milestones depending on the Resource Alternative

1) PPA:	Attachment 3 - Power Purchase Agreement (PPA) Appendix F - Bidder Site Control Form Appendix C-1 - PPA and TSA Information Request
2) TSA:	Attachment 5 – Tolling Service Agreement Appendix C-1 - PPA and TSA Information Request Appendix F - Bidder Site Control Form
3) EPC/APSA Bids at PacifiCorp Defined Site:	Attachment 4 – Engineer Procure and Construct (EPC) with Appendix – Currant Creek specifications Attachment 6 - Asset Purchase and Sale Agreement (APSA) with Appendices

	Attachment 17 – Specification for Currant Creek Site Appendix C-2 - Technical Information Summary
4) APSA Bids at Bidder Sites:	Attachment 6 - Asset Purchase and Sale Agreement (APSA) with Appendices Attachment 16 – O&M Term Sheet Appendix C-2 - APSA Information Request Appendix F - Bidder Site Control Form Bidder's form of O&M Agreement
5) Sale of Existing Facilities Bids :	Attachment 13– Due Diligence Items for the Acquisition of an Existing Facility Appendix C-3 – Existing Asset Purchase Information Request
6) Sale of Portion of Jointly Owned or Operated Bids:	Attachment 13 - Due Diligence Items for the Acquisition of an Existing Facility Appendix C-3 - Existing Asset Purchase Information Request
7) Restructuring Bids of an Existing PPA or an Exchange Agreement and/or Buyback of an Existing Sales Agreement:	Existing PPA or Exchange Agreement and Any other form deemed to be required to evaluate the restructuring proposal.
8) Exceptions: **a) Load Curtailment:**	Attachment 3 - Power Purchase Agreement
b) QFs:	Attachment 3 - Power Purchase Agreement Appendix C-1 - PPA Information Request Appendix F - Bidder Site Control Form Attachment 2 - QFs Bidder Information
c) Eligible Renewable Resources:	Attachment 3 - Power Purchase Agreement Appendix C-1 - PPA Information Request Appendix F - Bidder Site Control Form

SECTION 5. RESOURCE INFORMATION

A. PRICE AND NON-PRICE INFORMATION

The Company intends to rely on the outcome from this RFP to ascertain the most prudent resource decision. Bidders should note that the IRP is a useful document for information purposes and Bidders should not infer in any way that the IRP should prescriptively guide their specific proposal. The Company intends to use then-current assumptions in its evaluation of bids.

With respect to air quality standards, it is PacifiCorp's intent to incorporate cost assumptions into all bids that are consistent with the "then current assumptions." The base case assumptions are located in the 2011 IRP in Chapter 7, Modeling and Portfolio Evaluation Approach. This represents the best information available at the time the 2011 IRP was filed in March 2011. The base case will be updated through the RFP process and shared with the IEs.

This RFP will incorporate assumptions regarding the future cost, if any, associated with future tax assessment(s) or other impositions based on the quantity of CO_2 emissions produced from the combustion of fuel by a facility selected and contracted through this RFP. If a Bidder proposes a PPA, a source must be identified which will determine the CO_2 emissions. For bids with a specified facility, which would include an asset backed PPA; the potential CO_2-related expenses will be included in the Company's evaluation based on the asset identified by the Bidder as backing the resource. The CO_2-related expenses will be consistent with the reference case assumptions utilized in the 2011 IRP or the then current assumptions if applicable. The bid evaluation process will incorporate the assumption that the Bidder does not contractually absorb the liability associated with potential future CO_2 expenses. The foregoing notwithstanding, a bidder desiring to offer a bid in which it proposes to absorb some or all of any liability associated with CO_2 costs, may do so and will be reflected in the evaluation accordingly.

As such, if the bid does not provide for the passing through of such costs absent a pledge to absorb this liability, the bid evaluation process will incorporate the assumption that Bidders will pass through to PacifiCorp any costs associated with meeting future air quality requirements relating to specified facilities.

B. PRICE INFORMATION

1. Fixed & Variable Cost for Capacity and Energy

The Bidder – specified fixed O&M payment ($/kW-mo)

- **This value can be a fixed value or indexed to the Consumer Price index, the Gross Domestic Product, or a bidder-supplied fixed rate.**

Variable O&M ($/MWh)

- **This value can be a fixed value or indexed to the Consumer Price Index, the Gross Domestic Product, or a bidder-supplied fixed rate.**

a) Fixed Costs

The fixed resource costs will include, but are not limited to, the following components:

- The Bidder - specified capacity cost payment ($/kw-mo)
- The Bidder – specified fixed O&M payment ($/kw-mo)
- The Bidder – must include interconnection costs in their proposal and other costs (e.g., applicable transmission wheeling expense) necessary to deliver the energy to an interconnection point on PacifiCorp's system
- The Bidder – In the evaluation process, the Company will add the cost of transmission integration. The integration costs associated with the possible Points of Delivery in **Attachment 20** will be used, on a prorated basis, as a proxy cost in the initial shortlist. Bidders must identify the Point of Delivery in Section 4(C)(1). If the Bidder cannot determine if the Point of Delivery corresponds to one of the Points of Delivery in **Attachment 20** then the Bidder must request clarification with the Utah IE who will seek the determination from PacifiCorp's Transmission department.

b) Variable Costs

The variable generation costs will include, but are not limited to, the following components:

- The variable energy commodity price, which, depending on pricing structure, could take one of several forms. Energy commodity costs could (1) be based or indexed to a specified gas index, (2) could be established as the product of a fuel index value times the contractual heat rate, or (3) in certain structures, the variable energy commodity price can be fixed or indexed to the Consumer Price index, the Gross Domestic Product, or a bidder-supplied fixed rate.
- Variable O&M ($/MWh).
    - This value can be a fixed value with a fixed escalation and escalated using an index as described above.
- Transmission losses in those cases where the Company will incur third-party transmission losses (if applicable).
- Start costs (if applicable) per plant and per machine (if applicable). Bidders must define if this start cost is from initiation of start to synchronization, minimum sustainable load that the plant is in compliance or to full load. Start costs, operating hour costs and variable O&M cost must be clearly separated and defined. Cost presentation format provided by the Bidder should be in $/MWh terms and operating assumptions clearly defined.

C. NON-PRICE INFORMATION

1. Point(s) of Delivery

This RFP is requesting approximately 600 MW of cost-effective resources that are capable for delivery into or in the Company's network transmission system[20] in PACE or PACW. All proposals will be contingent on the ability of PacifiCorp's commercial and trading function ability to designate the proposed resource (new, existing, imported, etc.) as a Network Resource under the network service contract between PacifiCorp Transmission and PacifiCorp Commercial and Trading.

PacifiCorp is interested in resources that are capable of delivery into or in a portion of the Company's network transmission system in PACE or PACW. Specifically, the point(s) of delivery of primary interest to PacifiCorp are:

East system Points of Delivery (PACE)

- Salt Lake Valley
    - Connected to a major 138 kV or 345 kV substation in the Wasatch Front load area south of the Ben Lomond substation and north of the Camp Williams substation.

[20] Any costs required to upgrade PacifiCorp's electrical infrastructure (integration costs) will be considered in the overall economics of the resource. See **Attachment 20** for cost assumptions for Integration costs. If the Bidder is proposing another site that is not stated in **Attachment 20**, PacifiCorp will use the best available information at the time of evaluation to determine the integration costs for the analysis.

- PacifiCorp Sites
  - Currant Creek
- Mona 345 kV
- Glen Canyon 230 kV
- Nevada/Utah Border:
  - Gonder-Pavant 230 kV line known as "Gonder 230 kV"
  - Red Butte – Harry Allen 345 line known as "NUB" or Red Butte 345 kV
- Crystal 500 kV
- West of Naughton
  - Connected to a major 230 kV or 345 kV substation west of Naughton substation to the Utah border.

Although the Company will consider resources delivered to the following areas these areas have been identified as having potential transmission constraint implications and as such, will need to be evaluated accordingly:

- Wyoming, unless the resource(s) electrically reside south of the Naughton Monument 230kV line. If, resources in Wyoming are not electrically west of Naughton such resources may be useful in supporting the increased load and wind resources in Wyoming; however, such resources may be negatively affected by transmission constraints.
- All points of receipt which require transmission line construction will require 4-7 years and in some scenarios even longer in order to allow time for environmental work, route selection, permitting, and construction. Resources located at one of these Point of Receipt (POR's)'s may require cost adjustment for some period of time to accommodate re-dispatch of existing resources or other means of managing transmission congestion in the interim period between completion of plant construction and before new transmission is commissioned.
- Estimates provided in the document are conceptual (plus or minus 50%) un-scoped and provided for informational purposes. System impact studies completed for actual generation interconnection request may identify new constraints and impacts that significantly change the cost and schedule estimates provided here. Cost estimates and schedules provided in this document do not represent any firm offer of service.

PacifiCorp is willing to consider purchasing capacity and associated energy that is sourced from Desert Southwest (Nevada, California, Arizona, New Mexico); provided, the selling entity is able to purchase firm transmission from the resource to either Gonder or Nevada Utah Border.

West System Points of Delivery (PACW)

- Mid Columbia – Yakima Area
  - Midway 230 kV

  - Wanapum 230 kV
- California Oregon Border
- Portland
  - Troutdale 230 kV
- Willamette Valley
  - Alvey 500 kV
  - Fry 230 kV
- Southern Oregon
  - Chiloquin230 kV
  - Dixonville 230 kV
  - Meridian 230 kV
  - Reston 230 kV
- Central Oregon
  - Bend 69 kV
  - Pilot Butte 69/230 kV
  - Ponderosa 230 kV
  - Redmond 69 kV
- Oregon Coast
  - Astoria to Tillamook 115 kV
  - Boyer (Lincoln City) 115 kV

- Within the Western Control Area – The point of interconnection is the point between the resource, or the electrical system to which the resource is connected, and PacifiCorp's transmission system.

- Scheduled to the point(s) of interconnection between PacifiCorp's western control area and the Bonneville Power Administration or Portland General Electric such that transfer limitations are not exceeded. If the resource is located within the Bonneville control area the Bidder must show they have control area service from the resource to the delivery point.

- All points of receipt that require transmission line construction will require 4-7 years and in some scenarios even longer in order to allow time for environmental work, route selection, permitting, and construction. Resources located at one of these POR's may require cost adjustment for some period of time to accommodate re-dispatch (if possible) of existing resources or other means of managing transmission congestion in the interim period between completion of plant construction and before new transmission is commissioned.

2. Proposals Requiring Third-Party Interconnection and Transmission Service

For proposals that will require third-party transmission service to provide delivery of capacity and associated energy to the bid-specified Point of Delivery on PacifiCorp's west and east system, Bidders are responsible for any interconnection, electric losses, reserves, transmission and ancillary service arrangements required to deliver the proposed firm capacity and associated energy to the bid specified Point(s) of Delivery. Such proposals must identify all third-party interconnection, electric losses, transmission and ancillary service products, provider of reserves, and must provide a complete description of those service agreements, and provide documentation that such service(s) will be available to Bidder during the full term of offer(s) proposed.

Bidders who propose bids relying on third-party transmission should be aware that the use of transmission that is interruptible within the hour in any segment of the schedule and tag from the source to the Point(s) of Delivery will require the Company to evaluate the need to carry 100% reserves against the import schedule or the Bidder will need to explain and provide the agreement they have where a specific balancing authority is in fact providing reserves within the hour.

Bidders who propose unit contingent arrangements or system portfolio bids that are interruptible within an operating hour will require the Company to evaluate the need to carry 100% reserves against the import schedule or the Bidder will need to explain and provide the agreement they have where a specific balancing authority is in fact providing reserves within the hour.

3. Standards of Conduct

Each Bidder responding to this RFP must conduct its communications; implementation and operations in compliance with the Federal Energy Regulatory Commission's ("FERC") Standards of Conduct for Transmission Providers, requiring the separation of its transmission and merchant functions. The third-party transmission service is NOT a transmission service agreement with the Company's marketing function, the Commercial and Trading department; rather it is with PacifiCorp's transmission function, the Transmission Services department, or other third-party transmission providers.

4. PacifiCorp Transmission Interconnection & Transmission Services

This RFP requires that all Bidders must enter into a separate Interconnection Agreement if their facilities are located within the PacifiCorp footprint in accordance with PacifiCorp's Open Access Transmission Tariff ("OATT"). Bidders must advise PacifiCorp Transmission Services if its service is being requested as part of this RFP. Bidders requiring interconnection service from PacifiCorp Transmission should request

Energy Resources (ER) Interconnection Service.

All proposals that will require a new electrical interconnection to the PacifiCorp transmission system or an upgrade to an existing electrical interconnection to the PacifiCorp transmission system must include a statement of the cost of interconnection, together with a diagram of the interconnection facilities. The Bidder will be responsible for, and is required to include in its bid, all costs to interconnect to PacifiCorp's transmission system. The Bidder will be responsible for applying to PacifiCorp Transmission Services for a Large Generator Interconnection Agreement ("LGIA"), except in connection with the EPC Contract, in which case PacifiCorp Generation will apply for the LGIA. However, the interconnection costs from all Bidders will be included in the bid evaluation. **Bidders are reminded that they shall bear 100% of the costs to interconnect to PacifiCorp's transmission system**. Bidders are encouraged to contact PacifiCorp's Transmission Service department (at www.oasis.pacificorp.com) for information related to a system interconnection requests.

Once the Bidder is selected, funding of the interconnection upgrades, if any, will be allocated in accordance with existing FERC policy and in accordance with PacifiCorp's OATT. The Bidder may be required to fund such upgrades and then receive revenue credits per PacifiCorp's OATT. Any such revenue credits shall be assigned to the Company.

5. PacifiCorp Transmission Integration Service

Bidders should not factor in the cost of integrating the proposed resources from bid-specified Points of Delivery to PacifiCorp's system. Such integration costs will be factored in for determination of the Final Shortlist. PacifiCorp has preliminarily identified the high level potential costs to integrate resources from the bid-specified Points of Delivery to the PacifiCorp system. These costs are reflected in **Attachment 20**. These costs do not include interconnection costs which the Bidder is responsible to include in their bid. The Points of Delivery and the costs identified in **Attachment 20** are proxy costs to integrate resources into the system which will be used in the evaluation of the initial shortlist to determine the cost to integrate resources at those specific Points of Delivery.

In the event that a Bidder proposes a facility, PPA or TSA that is not at one of the locations identified in **Attachment 20**, the Bidder will seek clarification from the IEs, who will seek clarification from PacifiCorp Transmission Services as to the appropriate cost to use from **Attachment 20** for integration of the resources proposed to PacifiCorp's system.

6. Change of Law

In the event there is a change of law which increases the costs associated with this RFP, the Company will negotiate the allocation of such risks after identification of

the bidders on the Final Shortlist.

SECTION 6. BID EVALUATION PROCESS OF THE PROPOSALS

The Evaluation Team and the IEs will adhere to the following bid evaluation process.

A. OVERVIEW OF THE EVALUATION PROCESS

The analysis for the RFP will be focused on finding the best combination of resource opportunities to meet customer requirements at the least cost, on a risk adjusted basis and in the public interest. The evaluation process will utilize a screening process to derive an Initial Shortlist of bids that will be updated with those final best and final proposals from the Initial Shortlist (described in Step 1 below) and only the bids in the initial best and Final Shortlist will then be placed in a system wide production cost model to determine the Final Shortlist (described in Steps 2 and 3 below). The Company intends to utilize a "first price sealed bid format" in order to determine both the Initial and Final Shortlist of proposals.

The selection of an Initial Shortlist of bids will be based on price and non-price factors. All Bidders must submit **Attachment 19; Term Sheet**. The Company will provide the Bidder with a PDF of **Attachment 19** with any clarifying questions or edits. The Bidder will have two (2) working days to update the PDF and return it to the Company in both a PDF and word document via email to the RFP email box. **Attachment 19** will summarize the Bidders terms and pricing inputs for each bids submitted. Within 2 business days the Bidder will return the PDF and word document to the Company. This will be used to model the bidder inputs in the evaluation. The price factor will be derived, in the Initial Shortlist analysis, using the PacifiCorp Structuring and Pricing RFP Base Model.

The RFP Base Model will be used to establish the Initial Shortlist for each of the three Bid Categories: a Base Load category, an Intermediate Load category and a Summer Peak category. In performing the price evaluation for the Initial Shortlist for each Bid Category, the Company will use the RFP Base Model to calculate the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The non-price factors will evaluate the proposed resource characteristics, including development feasibility and risk, site control and permitting, and operational viability and risk impacts. The underlying criteria within each category are explained in more detail in Section 6.B.

Bids which qualify in the Initial Shortlist from a screening basis will be asked to provide their Best and Final pricing. Those Bids will be updated using the RFP model, if required. Once the Best and Final Bids are selected in the Initial Shortlist those Bids will be run through production cost models to establish a preferred portfolio and subsequently a Final Shortlist. After the Final Shortlist is determined, post-bid negotiations will take place. Under this format, contract payments will be based on the price contained in each winning bid proposal. The "first price sealed bid format" means that the Company will utilize the initial prices and/or pricing structure submitted by the Bidders in order to determine the initial short-listed entities. In selecting the RFP bids for contract negotiations, an optimization model will be used to pick the least cost portfolios of resource options from the Initial Shortlist under different sets of forecast assumptions (prices, emission expenses, etc.). Additional deterministic and stochastic analyses will be performed to support portfolio risk analysis of each of the optimal portfolios determined by the optimization model.

In selecting resources to be submitted for approval or acknowledgement as part of the Final Shortlist, the Company will take into consideration, in consultation with the IEs, certain other factors not expressly included in the formal evaluation process, but required to be considered by applicable law or Commission order.

The evaluation process described below is consistent with that used in the Company's IRP process and applicable laws and orders, and is expected to provide sufficient analytical basis from which to make resource choices. The evaluation will identify the resources most commonly included in the highest performing portfolios as the RFP "winners" that will then advance to contract negotiations. Portfolio performance is measured as the expected PVRR, adjusted for risk, and accounting for statutory public interest factors. The stochastic performance measure used to assess each resource set will be the risk-adjusted PVRR, which is calculated as the mean PVRR plus the expected value (EV) of the 95th percentile PVRR, where EV = $P(PVRR)_{95}$ x 5%.[21]

The Company will not ask for, or accept; updated pricing from Bidders during the evaluation period until the Best and Final pricing is requested of Bidders. Once the Company determines the Final Shortlist it is the Company's intent to negotiate both price and non-price issues during the post-bid negotiations. Selection for the initial shortlist, Final Shortlist, and/or post-bid negotiation does not constitute a "winning bid proposal." For the purpose of the RFP, only execution of the definitive agreement by both the Company and the Bidder that is specific to the Bidder's proposal, as the same may be amended pursuant to any post-bid negotiations, will constitute a "winning bid" proposal Bidders should also be aware that operational separation exists, pursuant to FERC's Standards of Conduct, between the merchant and transmission functions of PacifiCorp. As a result, PacifiCorp will require the Bidder to be responsible for the negotiation, execution and cost of interconnecting a resource or a contract of firm capacity with associated energy in or in to PacifiCorp's balancing authority area. The Bidder will be responsible for all incremental transmission expenses associated with delivery to PacifiCorp's network transmission system (inclusive of any third-party system upgrade needed to deliver such energy to PACE or PACW). Any anticipated transmission cost which is not included in **Attachment 20** or otherwise that is not disclosed in the Bidder's

[21] This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations.

response will be added by PacifiCorp using information reasonably and readily available during the economic evaluation phase.

Transmission integration costs will be used on a prorated basis in the development of the initial shortlist in Step 1. In the system wide production cost models utilized in Step 2 and Step 3, the transmission costs and system benefits (i.e. additional economic transactions, etc.) will be evaluated.

The Company will not make any of the evaluation models - the RFP Base Model, the System Optimizer model, and the Planning and Risk model - available to Bidders. The IEs will have full access to the inputs (including the Company's forward price projections) and all models used in the evaluation process.

B. THE EVALUATION PROCESS

Bids submitted in this RFP will be evaluated in three steps:

1. Step 1—Price and Non-price screen will be used to determine a list which will be deemed an initial shortlist for all proposals.

The Company intends to evaluate each bid received in a consistent manner by separately evaluating the non-price characteristics of the resource and the price characteristics. Each component will be evaluated separately and combined to determine the bundled price and non-price score. The price factor will be weighted up to 70%, while the non-price factor will be weighted up to 30%. No proposal will receive a total weighting in excess of 100%. The price and non-price evaluation will be added together and used to determine the initial shortlist for each Bid Category.

a) Price Factor Evaluation (Up to 70%)

The Company will utilize the RFP Base Model to screen the proposals and to assign the price ranking for the eligible bids received in the three Bid Categories: Base Load, Intermediate Load, and Summer Peak. The RFP Base Model will compare the cost of each proposal against the value of expected energy priced at the forward price curve.

<u>RFP Base Model Inputs (some inputs may not be applicable to all Resource Alternatives)</u>:

- Forward Prices
- Discount Rates
- Start and End Date
- Transmission Cost
  - Third-party wheeling
  - Integration
- CO_2 Emission Rates

- Rate Base Inputs
- Dispatch Restrictions (hours per day, hours per year, starts per day, etc.)
- Capacity and Heat Rate Degradation Curves
- Variable O&M ($/MWh)
- Operating Hour Costs ($ per operating hour)
- Start-up Costs ($/MWh)
- Fixed O&M ($/kW-mo)
- Daily Gas Capacity (MMBtu/day)
- Daily Gas Demand Charge ($/MMBtu-mo)
- Gas Transportation/Delivery Adder ($/MMBtu)
- Fuel Reimbursement/Gas Pipeline Losses (%)
- Energy Payment ($/MWh)
- Capacity Charge ($/kW-mo)
- Monthly Availability Rate
- Project cash flow Financial Inputs (Inflation, AFUDC rates, after-tax weighted average cost of capital, tax rates, etc.)

Calculation of the Price Score

The price score will be calculated for each proposal (and each alternative as applicable) using a market ratio metric. The market ratio will be expressed as a percentage and will be calculated by dividing the nominal levelized PVRR of expected energy value, expressed on a $/kW-mo basis, into the nominal levelized PVRR of proposal costs, expressed on a $/kW-mo basis. A market ratio less than 100% indicates that the PVRR of proposal costs are lower than the equivalent market alternative, and therefore favorable to customers. The market ratio will be used to assign a price score of between zero and 70% to each proposal (and each alternative as applicable) as set forth in the table below.[22]

Market Ratio	Price Factor Weighting
Less than or equal to 60%	70%
Greater than 60% but less than 140%	Linearly interpolated
Equal to or greater than 140%	0%

b) Non-price Factors (up to 30%)

Non-price factors will be used to establish a non price score of up to 30%. The non-price analysis will gauge the relative development, construction and operational characteristics and associated risks of each proposal. A matrix will be established for each non-price factor and will be used to compare the bids with one another. For each non-price factor, proposals will be assigned one of three discrete scores: (1) 100% of the percentage weight; (2) 50% of the percentage weight; or (3) 0% of the percentage weight. Bids will

[22] To the extent a majority of the proposals yield a market ratio above 140%, the upper market ratio limit of 140% will be adjusted and reviewed with the IEs in order to ensure that the majority of proposals are not ranked only on non-price score factors.

be evaluated based on their ability to demonstrate the proposal is thorough, comprehensive and provides limited risk to the buyer prior to the Company performing due diligence on any given Bid. Bids which have a demonstrated track record or are mature proposals will receive higher scores. Table 5 lists the key non-price criteria and the basis for weighting for each criteria.

Table 5

Non-price	Non-price Weighting Factor
Development Feasibility/Risk ▪ Critical Path Schedule 0-5% ▪ Engineering Design and Technology 0-2.5% ▪ Fuel Supply and Transportation Strategy 0-2.5%	Up to 10% Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and their ability to demonstrate that the project can be reasonably developed within the appropriate timeframe to meet the proposed in service date and with limited risk to the buyer. Bids which have achieved commercial operation will be awarded percentage weight consistent with the risk associated with each non-price category. For example, an existing project will be awarded 100% of the percentage weight associated with the Critical Path Schedule criteria.
Site Control and Permitting ▪ Permits Required 0-5% ▪ Access to Water Supply 0-2.5% ▪ Rights of Ways 0-2.5%	Up to 10% Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail on the status of permitting, access to available water supply and site control. Bids which can demonstrate little or no risk associated with these criteria will be more highly evaluated.
Operational Viability/Risk Impacts ▪ Safety Compliance/Strategy 0-1.0% ▪ Environmental Compliance/Strategy 0-2.5% ▪ Environmental Impact 0-1.5% ▪ Experience/Qualifications 0-2.5% ▪ O&M Plan 0-2.5%	Up to 10% Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and demonstration of sufficient detail regarding the quality of their environmental compliance plan and O&M plan as well as the environmental impact of each proposal consistent with the proposed technology.

Development Feasibility/Risk

This category is intended to assess the likelihood the project can be successfully developed as proposed, based on a number of factors which influence project development feasibility and risk of development. Factors influencing the status of project development as well as the likelihood the project will be developed on schedule will be assessed. For this category, PacifiCorp will evaluate the Critical Path schedule provided by the Bidders, the engineering design and technology maturity for the project proposed, the status of fuel supply arrangements and the strategy of the Bidder for securing fuel for the project.

Bidders shall provide a detailed project schedule with critical path milestones for the project that include activities from the period of selection as the winning bidder to the commercial operation date. PacifiCorp will review and evaluate the project schedule to ensure there is a high likelihood the project can reach commercial operations as proposed. This review will include the risks of delays in securing the necessary environmental permits.

Bidders should also provide information about specific technology and equipment proposed for the project, including a description of the track record of the technology and equipment. The Bidder should provide a detailed description and specifications for the proposed equipment (including the turbine, steam generator, cooling equipment and environmental control equipment proposed). PacifiCorp reserves the right to conduct further due diligence on the equipment. PacifiCorp prefers proposals that demonstrate that the generation design and equipment proposed is technologically mature and the Bidder has included a reasonable plan to address how the project will conform to change in environmental requirements in the future.

Bidders should provide a detailed strategy for securing and delivering fuel to the plant site. If the project is in the early stages of development, PacifiCorp requires a fuel supply and transportation plan that demonstrates that the fuel supply arrangements adequately conform to the type of project/technology proposed (*e.g.* gas-fired combined cycle). PacifiCorp prefers proposals that can demonstrate a secure and reliable fuel supply or strategy which demonstrates the ability of the Bidder to secure a reliable supply for the project.

Site Control and Permits

Bidders must be able to 1) document they have obtained site control and provide documentation on which necessary permits have been obtained (maximum points in this category) or 2) demonstrate how site control and permits will be obtained. To meet the site control requirement, Bidders shall have identified a site and must provide a copy of documentation establishing that the seller has and/or will have control over the site for the entire term of the contract. Eligible documentation includes a demonstration of site ownership, an option to purchase the site, or a binding letter of intent from the landowners for the full term of the contract. The Bidder must be able to obtain site control prior to signing a contract with the Company.

For Bidders to demonstrate how they will obtain site control, they must submit documentation which supports the site control requirements. Bidders should also provide a list of all required permits that must be obtained. In addition, Bidders should identify any rights-of-ways that need to be acquired for the construction of supporting facilities (i.e. water pipelines, fuel lines, transmission lines, rail spurs, etc.) and provide a plan and schedule for securing the rights-of-ways.

Finally, PacifiCorp is particularly interested in the plan proposed by the Bidder for securing necessary water rights for the project, including the sources of water and status of any agreements in place to secure and deliver the water to the project site.

Operational Viability/Risk Impacts

This category addresses key viability and risk factors associated with project operations. The five key factors of importance are the Bidder's safety management and compliance plan, environmental management and compliance plan, the proposal's environmental impacts, the Bidder's experience/qualifications on similar work, and the Bidder's O&M plan. The safety and environmental management and compliance criteria address the ability of the generation facilities supporting the project to anticipate and remain in compliance with existing and future safety and environmental regulatory requirements and to reduce environmental impacts. Bidders should, to the extent practicable, explain and justify their choices of pollution control and water cooling technologies. PacifiCorp is interested in proposals that can demonstrate, through a credible plan, the ability to mitigate safety risks and manage and reduce environmental costs and impacts. Options to meet the requirements of developing regulations for control of currently regulated air emissions and mercury, along with emerging issues such as greenhouse gas emissions and ways to mitigate future CO_2 impositions, should be included in the Bidder's strategy for meeting the necessary requirements.

An important criterion for evaluating proposals will be the project's environmental impacts. The proposal's overall plan to minimize air emissions will be an important aspect of this review. In addition, site impacts such as water usage, land use, waste disposal, etc. will be considered. Proposals should include a description of the Bidder's plan to address site-specific areas of environmental sensitivity. Bidders are encouraged to identify areas where incremental improvements in environmental performance and water use and efficiency can be made through more advanced pollution control and water cooling technologies, if applicable, and to provide projected cost analysis for such incremental improvements, and tradeoffs with other factors like fuel use and air emissions. If a Bidder is not able to address this issue fully in its initial bid submission, it should identify any additional information it will be prepared to provide in the event its bid moves from the Initial Shortlist to the Final Shortlist.

The Bidder is also required to provide an O&M plan for the proposal. The O&M plan should include any plans for the Bidder to execute a long-term contract with a reputable O&M provider, a description of the funding levels/mechanism and contractual arrangements, and a description of the previous experience of the Bidder in operating and maintaining similar facilities.

c) Total Score (up to 100%)

The initial shortlist will be established using the combined price and non-price results, and will be established for each of three Bid Categories: Base Load, Intermediate Load, and Summer Peak. For Bidder's that include proposal alternatives, only the top performing option will be considered the eligible proposals for evaluation puposes. Bidders will be asked to update to provide their Best and Final proposals which will be further updated using Step 1 for selection to the initial shortlist. The Company will quantify whether a proposal exceeds the 10% cost increase limit using the RFP Base model, which is the model used to establish the initial shortlist. The nominal levelized present value revenue requirement of both fixed and variable costs, quantified on a $/kW-mo basis, will be calculated consistent with the best and final pricing offered by the Bidder and divided by the same metric calculated consistent with the original pricing. The 10% cost increase limit will have been exceeded if the result of this calculation exceeds 1.10, which would reflect a cost increase in excess of 10% to the original proposal. If Bidders increase their overall pricing when they submit their best and final pricing by more than 10% from their original submission, they may be eliminated by the Company after the Company consults with the Independent Evaluators. The Company will target to select up to twice the megawatt quantity in each of the three Bid Categories.

The Final Shortlist will be comprised of Step 2 and Step 3.

2. Step 2—System Optimizer Capacity Expansion Model - Optimized Portfolio Development

Based on the initial shortlist,Ventyx Energy LLC's System Optimizer model will be used to develop optimized portfolios under various assumptions for future emission expense levels and market prices. System Optimizer will develop a corresponding number of optimized portfolios-—one for each combination of emission and wholesale market and natural gas price assumptions—drawing from resource options in the initial shortlist (described above). These assumptions will be conceptually consistent with the 2011 IRP low, medium, and high cases, but may reflect more recent data at the time the analysis is conducted. An optimal portfolio will be established for each combination of emission and wholesale market and natural gas price assumptions.

In the event that a bidder proposes to absorb some or all of the risk of future carbon emission costs that the benefits of the bidder absorbing future risk of carbon emissions will be conducted in Step 4 of the RFP. The starting point for System Optimizer portfolio development is the set of preferred resources and input assumptions that will be consistent with PacifiCorp's 2011 IRP.[23] The resource in the year for which there is a capacity need as defined by the resource portfolio will be removed in order to create a capacity deficit that the model must fill with one or more bid resources. (The model will also be allowed to select a variable quantity of firm market purchases, or "front office transactions" to ensure that a specified annual planning reserve margin is maintained throughout the simulated period.) If assumption updates are made prior to the receipt of Bidders' best and final pricing for proposals selected to the initial shortlist which affect the timing and/or size of the resource need, the portfolio may be revised accordingly. Resources not removed to create a capacity deficit, except for front office transactions and natural gas-fired supply resources, will be fixed for all portfolios to remove the impact of out-year resource optimization on bid resource selection.

The System Optimizer will produce an optimized portfolio for each combination of carbon dioxide (CO_2) and natural gas price assumptions input into the model ("price scenarios"). In addition to a base case price scenario, additional price scenarios will be modeled. The price scenarios will be locked down by the IEs prior to receipt of bids.

Each System Optimizer portfolio will be a candidate for the optimum combination of resources to be selected through the RFP process and will therefore be advanced to the stochastic analysis step described below. Resources bid into the RFP that are not included in any of the portfolios resulting from this step will no longer be considered candidates for acquisition by the Company.

3. Step 3—Risk Analysis

Stochastic and deterministic risk analyses will be performed on each optimized portfolio advanced from Step 2 of the evaluation process. Consistent with the IRP, the Company will use the Planning and Risk model (PaR) to assess stochastic risks and the System Optimizer model to further quantify scenario risk.

a) Stochastic Analysis

The unique portfolios from Step 2 will be simulated using PaR in stochastic mode. The PaR simulation produces a dispatch solution that accounts for chronological unit commitment, dispatch, and transmission constraints.[24] Stochastic risk is captured in PaR results by using Monte Carlo random sampling of five variables: loads, commodity natural gas prices, wholesale electricity prices, hydro energy availability, and thermal unit

[23] Certain assumptions may be updated to reflect more current inputs. All such assumption updates will be reviewed with the IEs.
[24] In contrast, the System Optimizer does not model unit commitment or the holding of reserves.

availability for new resource options. The simulation is conducted for 100 model iterations using the sampled variable values.[25] To capture CO_2 emission costs and associated dispatch impacts, simulations will be conducted using the CO_2 tax values modeled for Step 2 above. This model set-up is consistent with the stochastic simulations conducted in the IRP.

Capital and fixed costs resulting from the System Optimizer portfolios developed in Step 2 of the evaluation process will be added to the net variable cost from the PaR simulation to derive a real-levelized PVRR. For each simulation, the stochastic cost and risk measures calculated include the following:

- Mean PVRR – Mean of the PVRR for the 100 simulation iterations
- Mean Upper-tail PVRR – This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs are computed.
- 95^{th} percentile PVRR – The PVRR of the iteration that represents the 95^{th} percentile for the 100 simulation iterations.
- Risk-adjusted PVRR – Calculated as the mean PVRR plus the expected value (EV) of the 95^{th} percentile PVRR, where EV = P $(PVRR)_{95}$ x 5%.
- Variable cost standard deviation – A measure of production cost variability risk, calculated as the standard deviation of annual variable costs for the 100 simulation iterations.
- Average annual Energy Not Served – Energy Not Served (ENS) is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. The stochastic ENS results are averaged across all 100 iterations and reported on an average annual GWh basis for the 20-year simulation period.
- CO_2 emissions footprint – The amount of CO_2, in tons, attributable to generation sources (direct emissions).

b) Deterministic Scenario Analysis

As an additional risk analysis step, the optimal portfolios will be subjected to a more in-depth deterministic dispatch model using the System Optimizer, with each portfolio being assessed for each of the future scenarios described in Step 2 above. For example, Portfolio 1 will have been optimized for Scenario 1, but in this step Portfolio 1 will be reevaluated under the other scenarios in order to assess the consequences of choosing a portfolio if other futures are realized. This step is intended to identify portfolios with

[25] Based on a sample size statistical analysis conducted for the 2004 IRP, PacifiCorp determined that 100 iterations exceeded the minimum number needed to be confident (at least at a 95% confidence level) that the sampled iteration mean is close to the true iteration mean. See Appendix G, pp. 98-99, of the 2004 IRP for details on the statistical analysis.

especially poor performance under certain future scenarios and used to inform the selection of final resource options.

Inputs used in System Optimizer and PaR®

Operational Costs
For each portfolio, the operational information for each added proposal will be entered into the production cost simulation (System Optimizer or PaR®). In addition, the Company will include any changes to the system topology to reflect transmission upgrades required by the added proposals. The operational information used in the production cost simulations includes:

1. Maximum capacity of each unit
2. Minimum capacity of each unit
3. Dependable per-unit capacity
4. Peaking capacity, for use under specified conditions
5. Actual pre-specified commitment and/or unit dispatch
6. Daily charge for operating a unit for at least one hour in the day
7. Variable O&M cost of each unit
8. The heat rate curve for a unit, plus any peaking capacity
9. Pre-scheduled maintenance, number of units and duration
10. Maintenance rate, for distributed maintenance per unit
11. Mean, maximum, and minimum time to repair, for outages scheduled by Convergent Monte Carlo
12. Minimum up- and downtimes of a unit
13. Per-hour operating cost, exclusive of fuel and variable O&M costs
14. Pumped storage pumping capacity and pumping minimum
15. Unit ramp rates (down and up)
16. Unit start-up O&M and fuel required for startup costs 17. Emission rates/costs

Bidders should ensure that they provide the information necessary to undertake the evaluation in their proposal. All the above items should be located in the Pricing Input sheet. The production-cost model simulations (System Optimizer and PaR®) will provide information on net system costs for fuel, variable plant O&M, unit start-up, market contracts and spot market purchases and sales.

Fixed Costs
As mentioned above, the revenue requirement costs associated with additional investments required by the bid—investment in new resources and/or transmission—will be added to the variable operating costs. The information required for new resources in order to calculate the fixed costs include:

1. Capital Costs—generation and transmission
2. Fixed O&M

3. Expected on-going capital costs
4. Incremental Transmission Asset Life
5. Incremental Resource Asset Life

4. Step 4 – Final Selections; Other Factors

The first three steps described above constitute the formal evaluation process and will lead to the compilation of the final shortlist of resources for further negotiation. After completing the formal evaluation process described above, but before making the final resource selections to be submitted for approval or acknowledgement, the Company will take into consideration, in consultation with the IEs, certain other factors that are not expressly or adequately factored into the formal evaluation process, but that are required by applicable law or Commission order to be considered, including any reasonable risk mitigation measures offered by a Bidder. The Company may consider creative means, proposed by Bidders, to absorb and securitize any CO_2 risk consistent with multi-state legal and regulatory requirements. The foregoing notwithstanding, a Bidder desiring to offer a bid in which it proposes to absorb some or all of any liability associated with CO_2 costs, may do so. In addition the Company will evaluate if there are any uncertainties associated with the Gateway transmission project. To the extent bidders submit a geothermal project and the company can quantify additional benefits to the Company it will be done in step 4.

The Company may also evaluate and include prudent costs associated with direct and or indirect debt consistent with the information outlined in Section 3(h)(5) and (6) when seeking approval, cost recovery or acknowledgement of the selected resource(s). In addition, the Company will consider the multi-state cost allocation process in evaluating all bids.

The Utah Energy Resource Procurement Act requires consideration of at least the following factors in determining whether a resource selected by the Company should be approved as in the public interest:

- 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;
- long-term and short-term impacts;
- risk;
- reliability;
- financial impacts on the affected electrical utility; and
- other factors determined by the Commission to be relevant.

SECTION 7. AWARDING OF CONTRACTS

A. INVITATION

This RFP is merely an invitation to make proposals to the Company. No proposal in and of itself shall constitute a binding contract. The Company may, in its sole and absolute discretion, perform any one or more of the following:

- Determine, in consultation with the IEs, which proposals are eligible for consideration as proposals in response to this RFP.
- Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each Bidder.
- Disqualify proposals contemplating resources that do not meet the definition of Base Load, Intermediate Load or Summer Peak resources in this RFP.
- Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
- Negotiate and request Bidders to amend any proposals.
- Select and enter into agreements with the Bidders who, in the Company's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interest of the Company, its customers, and state legal and regulatory requirements, and not necessarily on the basis of any single factor alone.
- Issue additional subsequent solicitations for proposals.
- Reject any or all proposals in whole or in part.
- Vary any timetable.
- Conduct any briefing session or further RFP process on any terms and conditions.
- Withdraw any invitation to submit a response.

B. POST-BID NEGOTIATION

The Company will further negotiate all terms and conditions during post-bid negotiations. The Company will continually update its economic and risk evaluation until a definitive agreement acceptable to the Company in its sole and absolute discretion is executed by both parties. The Company will allow Bidders to negotiate final contract terms that are different from the Pro Forma Agreements however changes to the Pro Forma Agreements will not be viewed favorably by the Company.

C. CONFIDENTIALITY AGREEMENT

All parties will be required to sign Confidentiality Agreements if they qualify for the Final Shortlist **(Attachment 11)** prior to entering into negotiations with the Company.

D. NON-RELIANCE LETTER

All parties will be required to sign a non-reliance letter if they qualify for the Final Shortlist **(Attachment 12)** prior to entering into negotiations with the Company.

Docket No. UM-1182
Exhibit PAC/203
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-07-05**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Steven R. McDougal**
ELECTRIC SERVICE SCHEDULES	)	
	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-07-05

June 2007

additional $5 million of insurance proceeds plus associated liabilities from PacifiCorp. This adjustment includes $1,069,257 of unspent insurance proceeds as a reduction to Idaho-allocated rate base.

Customer Advances for Construction (page 8.6) – This adjustment is required to properly assign customer advances for construction that were allocated system-wide in the unadjusted data. This adjustment reduces Idaho rate base by $499,058.

Centralia Transmission Line Sale (page 8.7) – In December 2006, the Company completed the sale of the Centralia transmission line to TransAlta Centralia Generation LLC. This adjustment removes the net investment and depreciation expense originally included in results.

Major Plant Additions (page 8.8) – This adjustment places into rate base one-half of major plant additions (defined as projects $2 million or greater) added during calendar year 2006 (added as a type II adjustment) and calendar year 2007 (added as type III adjustment). Current Creek Phase II, Leaning Juniper, and the Huntington Unit II scrubber make up the majority of the additions added in 2006. For 2007 major projects include the Lake Side generation facility, Marengo and Goodnoe Hills wind projects, and the Blundell bottoming cycle investment, along with significant transmission investments. A complete list of these projects is included on pages 8.8.2 - 8.8.5. Each generation resource investment was weighted by the in-service date to align the rate base investment with its inclusion in the calculation of net power costs. The accumulated depreciation reserve was also adjusted to match the depreciation expense and retirements calculated as described earlier. Exhibit No. 13 is a summary of the revenue requirement related

Rocky Mountain Power
Idaho General Rate Case
Major Plant Addition Detail - Jan2007 to Dec2007

Project Description	Account	Factor	In-Service Date	Jan07 to Dec07 Plant Additions
Steam Production				
303 Secondary SH Replacements	314	SG	Jun-07	2,158,370
U3 Replace Coal Pipe	314	SG	May-07	2,187,403
303 FGD Tower Linings	314	SG	Jun-07	2,569,426
303 Turbine HP Nozzle Box	314	SG	Jun-07	2,589,404
303 Bottom Ash Repairs	314	SG	Jun-07	2,593,624
U2 - Turbine - Generator Major	314	SG	Dec-07	3,270,276
303 Turbine L-0 Bucket Replacements	314	SG	Jun-07	3,347,319
U3 Reheater Replacement	314	SG	Aug-07	4,015,512
303 Reheater Replacements	314	SG	Jun-07	5,021,737
JB U3 NOX	314	SG	Dec-07	5,777,792
HTR U3 NOX	314	SG	Dec-07	8,524,625
303 Main Controls System Upgrade	314	SG	Nov-07	9,118,064
Blundell Bottoming Cycle	314	SG	01-Nov-07	27,700,643
Steam Production Total				**78,874,195**
Hydro Production				
Irongate Tunnel	332	SG-P	Oct-07	2,545,231
North Umpqua Implementation	332	SG-P	Jun-07	2,925,430
Copco 2 Electrical Overhaul	332	SG-P	Dec-07	6,839,344
Hydro Production Total				**12,310,005**
Other Production				
Goodnoe Hills	344	SG	15-Nov-07	196,572,406
Marengo Wind Project	344	SG	01-Aug-07	258,541,351
Lake Side Capital Build	344	SG	30-Jun-07	330,841,583
Other Production Total				**785,955,340**
Transmission				
McClelland Emigration Tap 1.4Mi OH Line	355	SG	Dec-07	2,122,182
Emery Moore 69kV Add	355	SG	Jul-07	2,418,912
Transmission Relay Repl Zone 3 Setting	355	SG	Dec-07	2,546,723
Oakley-Kamas line	355	SG	Dec-07	3,469,191
Shute Creek To Mona System Upgrade Study	355	SG	Dec-07	3,945,882
Craven Crk Provide 230kV Svc to Enterprise Prod-Pioneer	355	SG	Jul-07	5,108,986
Copco transformer 250 MVA	355	SG	Sep-07	7,695,049
Marengo Wind Project	355	SG	Apr-07	7,866,514
Line 1 Conversion Project, Convert Line 1 to 115 kV	355	SG	Dec-07	8,703,240
Upper Green River Valley project	355	SG	Nov-07	9,013,738
Summit Vineyard (Lake Side) Trns Interconnect	355	SG	May-07	9,861,575
Cache Valley Add. Bridgerland Sw St Ph 1	355	SG	Jul-07	15,505,664
Chappel Creek - provide 230kV service to Jonah Field	355	SG	Dec-07	16,102,548
Camp Williams-Mona 345kV #4 Line Project	355	SG	Jun-07	24,253,547
Summit Vineyard Lake Side Transmission	355	SG	Sep-07	44,549,831
Transmission Total				**163,163,582**

CONFIDENTIAL
Docket No. UM-1182
Exhibit PAC/204
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

Docket No. UM-1182
Exhibit PAC/205
Witness: Stacey J. Kusters

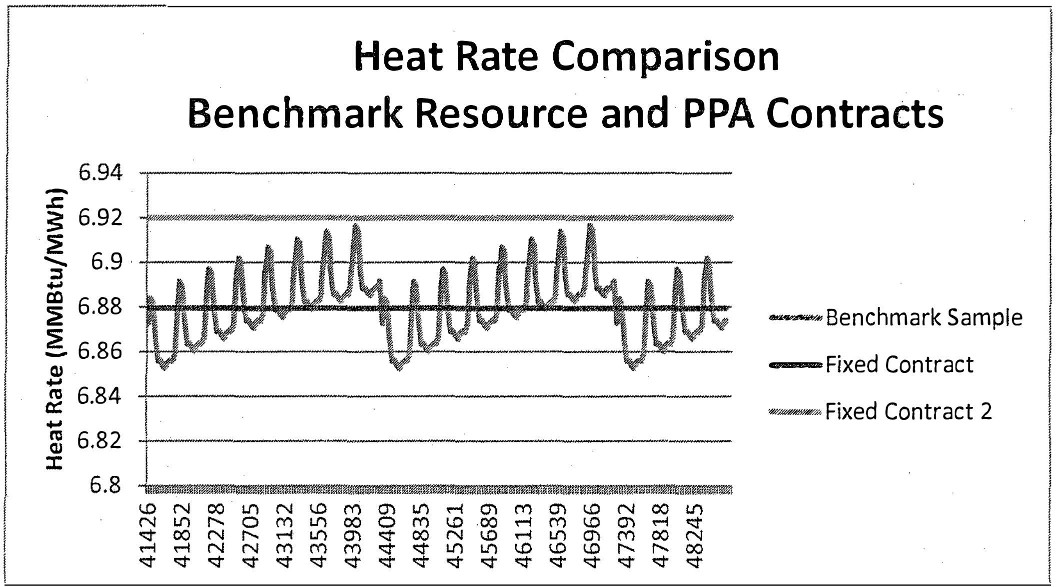
BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013


Heat Rate Comparison
Benchmark Resource and PPA Contracts
Heat Rate (MMBtu/MWh)
6.94
6.92
6.9
6.88
6.86
6.84
6.82
6.8
41426
41852
42278
42705
43132
43556
43983
44409
44835
45261
45689
46113
46539
46966
47392
47818
48245
Benchmark Sample
Fixed Contract
Fixed Contract 2

CONFIDENTIAL
Docket No. UM-1182
Exhibit PAC/206
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

CONFIDENTIAL
Docket No. UM-1182
Exhibit PAC/207
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

Docket No. UM-1182
Exhibit PAC/208
Witness: Stacey J. Kusters

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Stacey J. Kusters

January 2013

PACIFICORP ALL SOURCE RFP
POWER PURCHASE AGREEMENT

dated as of [______________], 2012,

BETWEEN

[*Bidder*],
as Seller,

AND

PACIFICORP,
as Buyer

[__________________________ Facility]

[__________, [*State*]]

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Exhibit O	Dispatch Procedures
Exhibit P	Net Energy Specifications and Dispatchable Quantities of Net Energy
Exhibit Q	Guaranteed Performance Parameters
Exhibit R	Dispatch Notice
Exhibit S	Credit Matrix ***[Note to bidders: Credit Matrix attached as Appendix to All Source RFP]***
Exhibit T	Form of Lender Consent

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT dated as of [__________], 2012 (this "**Agreement**"), is made and entered into between [__________], a [*describe entity*] ("**Seller**"), and PacifiCorp, an Oregon corporation, acting in its merchant function capacity ("**Buyer**"). Seller and Buyer are referred to collectively as the "**Parties**" and individually as a "**Party**."

RECITALS

A. Seller intends to develop, construct, own, operate and maintain [Insert Resource] [*consisting of* [_?_] *insert further description*] for the generation of electric energy located in [__________] County, [*State*], whose initial Facility Capacity shall be [___] MW (as more fully described in **Exhibit A**, the "**Facility**").

B. Seller responded to a Request for Proposals – PacifiCorp 2016 RFP. Buyer's objective in issuing the RFP was to fulfill, through a competitive bid process, a portion of its supply-side resource need as contemplated in Buyer's ____ Integrated Resource Plan.

C. Buyer's selection of Seller was based upon a competitive bid and was, in part, based upon Seller's representations and warranties, Seller's schedule achieving the Guaranteed Commercial Operation Date (initially capitalized terms not defined in these Recitals are defined in Section 1 below), and the guaranteed performance of the Facility, all as set forth herein. Such matters were a material inducement for the selection of Seller, and Seller's failure to perform in accordance with the terms and conditions or Seller's failure to meet its representations and warranties and schedules for delivery of Net Energy shall cause material damage to Buyer.

D. Seller will make available and sell to Buyer, and Buyer will receive and purchase from Seller, Contract Capacity and Net Energy associated with such Contract Capacity pursuant to the terms and conditions of this Agreement. Seller understands that Buyer will include such Contract Capacity in Buyer's resource planning.

AGREEMENT

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements set forth below, the Parties agree as follows:

SECTION 1

DEFINITIONS; RULES OF INTERPRETATION

1.1 Defined Terms. Unless otherwise required by the context in which any term appears, defined terms used in this Agreement (as indicated by initial capitalization, except as otherwise provided in this Section 1.1) shall have the following meanings:

"**AAA**" is defined in Section 15.2.

"**Abandonment**" means (1) the relinquishment of all possession and control of the Facility by Seller, other than pursuant to a transfer permitted under this Agreement, or (2) if after commencement of the construction, testing. and inspection of the Facility, and prior to the Commercial Operation Date, there is a complete cessation of the construction, testing, and inspection of the Facility for ninety (90) consecutive days by Seller and Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or request by, Buyer, or an event of Force Majeure.

"**Affiliate**" means, with respect to any entity, each entity that directly or indirectly, controls or is controlled by or is under common control with such designated entity. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlled by" and "under common control with"), as used with respect to any entity, shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such entity, whether through the ownership of voting securities or by contract or otherwise. Notwithstanding the foregoing, with respect to Buyer, Affiliate shall only include MidAmerican Energy Holdings Company and its direct, wholly owned subsidiaries.

"**Alternate Representative**" is defined in Section 6.4.2.

"**Ambient Facility Capacity**" means the Contract Capacity determined from the correction algorithms set forth in **Exhibit M**, based upon the Facility Capacity and the ambient conditions in effect in each hour.

"**Ancillary Services**" means those services and energy from time to time now or hereafter available that are necessary to support the Contract Capacity and transmission of energy from resources to loads while maintaining reliable operation of the System in accordance with Prudent Electrical Practices. Such services and energy include regulation reserve, spinning reserve, non-spinning reserve, voltage support, black start Capacity, and reactive power.

"**As-built Supplement**" shall be a supplement to **Exhibit A** that describes the Facility as actually built and shall include an American Land Title Association survey of the Premises and all such information as may reasonably be requested by Buyer.

"**Authorized Representative**" is defined in Section 6.4.2

"**Availability Notice**" is defined in Section 6.5.1.1.

"**Baseload Capacity**" means the Capacity of the Facility achieved when operating at the Reference Conditions with all items of Major Equipment operating at full load, but without duct firing.

"**Business Day**" means any day on which banks in Portland, Oregon are not authorized or required by Requirements of Law to be closed, beginning at 6:00 a.m. and ending at 5:00 p.m. local time in Oregon.

"**Btu's**" means British Thermal Units.

"**Buyer**" is defined in the Preamble.

"**CAF_h**" is defined in Section 5.1.2.

"**CAF_m**" is defined in Section 5.1.2.

"**Capacity**" means the output potential a machine or system can produce under specified conditions as generally expressed in kW or MW.

"**Capacity Payment**" means the Monthly Capacity Payments and the Minimum Monthly Capacity Payments payable in accordance with Section 5.1.

"**Capacity Payment Rate**" means, as of the Commercial Operation Date, $[**?**]/kW/month.

"**Capacity Payment Shortfall**" is defined in Section 5.1.4.

"**Capacity Rights**" means any current or future defined characteristic, certificate, tag, credit, ancil ary service attribute, or accounting construct, including any accounting construct counted towards any current or future resource adequacy or reserve requirements, associated with the Capacity of the Facility or the Facility's capability and ability to produce energy, but excluding any of the foregoing attributable to any expansion of the Facility occurring after the Commercial Operation Date, unless the output associated therewith is purchased by Buyer.

"**Carry-Over Letter of Credit**" is defined in Section 5.1.4.

"**Cash Escrow**" means an escrow account established by Buyer in a commercial bank or trust company organized under the laws of the United States of America or a political subdivision thereof, whose long-term senior unsecured debt is rated at least "A" by S&P and "A2" by Moody's, and with assets (net of reserves) of at least $10,000,000,000. Cash deposited to the escrow account shall earn interest at the rate applicable to money market deposits at the banking institution from time to time, and the interest shall be retained in the escrow account as additional security for Seller's performance under this Agreement.

"**CC**" is defined in Section 5.1.2.

"**Collateral**" is defined in Section 7.5

"**Combustion Turbine**" or "**CT**" means any one of the combustion turbines comprising the Facility.

"**Commercial Operation Date**" means the date on which the Facility is fully operational, reliable and each condition set forth in Section 2.2.6 has occurred and is and remains continuously satisfied as of the date and moment on which Seller gives Buyer notice that Commercial Operation has occurred.

"**Contract Capacity**" means [___] MW of Capacity from the Facility, comprised of **[?]** MW of Baseload Capacity and **[?]** MW of Peakload Capacity[if applicable].

"**Contract Year**" means a twelve (12) month period commencing at 00:00 hours on January 1 and ending on 24:00 hours on December 31; *provided, however*, that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the last Day of the Term.

"**CPR**" is defined in Section 5.1.2.

"**CPS**" is defined in Section 5.1.2.

"**Credit Matrix**" means the credit matrix attached hereto as **Exhibit S**.

"**Credit Rating**" means, as of any date, the lower the lower of: (x) the most recently published senior, unsecured long-term debt rating (or corporate rating if a debt rating is not available) from S&P or (y) the most recently published senior, unsecured debt rating (or corporate rating if a debt rating is not available) from Moody's. If option (x) and (y) are not available, the Credit Rating will be determined by the Company through an internal process review and utilizing a proprietary credit scoring model developed in conjunction with a third party.

"**Credit Support**" means, prior to the Commercial Operation Date, the amounts, if any, and subject to Section 7.1, shown on the Credit Matrix.

"**Credit Support Security**" means a guaranty, Letter of Credit or Cash Escrow provided pursuant to Section 7.1.

"**CT Start**" means the process of rotating any of the Facility's Combustion Turbine rotors by means of such Combustion Turbine's starting motor and subsequently introducing and igniting Fuel in the Combustion Turbine's combustor and increasing the rotating speed of the unit's rotor sufficiently that the starting motor can be disengaged, also referred to herein as the Start-Up of a Combustion Turbine. [If Applicable]

"**Daily Delay Damages**" for each Day shall be the positive number (and if not a positive number, zero) equal to the sum for all hours of the Day of the product for each hour of the Day of (1) the ICE™ SP15 Electricity Price Index for such Day, expressed in $/MWh, *multiplied by* (2) the applicable hourly scalar set forth in **Exhibit D** for the applicable hour in the daily (i) firm on-peak, (ii) firm off-peak or (iii) 24-hour firm (on Sundays and NERC holidays) Dow Jones™ SP15 Electricity Price Index (each such hour, the "**Applicable Hour**") during such Day, *multiplied by* (3) the loss factor of 1.112, *plus* (4) the basis of $13/MWh for each Applicable Hour or portion thereof during such Day, *minus* (5) one-twenty-fourth of the Capacity Payments and Energy Payments that would have been made with respect to such Day, if no Capacity Payments or Energy Payments have been paid with respect to such Day. If the Dow Jones™ SP15 Electricity Price Index ceases to be published during the Term, Buyer shall select as a replacement electricity price index or component, an index acceptable to Buyer in its discretion that, after any necessary adjustments, provides the most reasonable substitute quotation of the daily price of firm on-peak, firm off-peak or 24-hour firm energy at South of Path 15 for the applicable periods.

"**Day**" means the 24-hour period beginning at midnight PPT on a day and ending at midnight PPT on the next succeeding day.

"**Delivery Point**" means the physical points for Seller's delivery, and Buyer's receipt, of Net Energy at which the Facility is connected with the Transmission Provider's transmission system, as specified in the Interconnection Agreement and in **Exhibit B**. [***Note to Bidders: If energy is to be delivered to a transmission provider other than the Transmission Provider and wheeled to the Delivery Point, the Delivery Point will be at a point of interconnection with the Transmission Provider's transmission system where the resource can be integrated as a PacifiCorp Network Resource.***]

"**Dispatch**," "**Dispatched**," and "**Dispatching**" means the scheduling and control by Buyer of Net Energy, through submittal of schedules pursuant to the Dispatch Procedures and other provisions of this Agreement.

"**Dispatch Procedures**" means the procedures under which Buyer is entitled to Dispatch the Facility, as set forth in **Exhibit O**.

"**Dollar**" or "$" means the lawful currency of the United States of America.

"**Effective Date**" is defined in Section 2.1.

"**Electric System Authority**" means each of NERC, WECC, an RTO, a regional or sub-regional reliability council or authority, and any other similar council, corporation, organization or body of recognized standing with respect to the operations of the electric system in the WECC region.

"**Electrical Interconnection Facilities**" means all the facilities installed by Seller for the purpose of interconnecting the Facility to the Delivery Point, including electrical transmission lines, upgrades, transformers and associated equipment, substations, relay and switching equipment, and safety equipment, as set forth in **Exhibit B.**

"**Electric Metering Equipment**" is defined in Section 8.1.

"**Energy Payment**" means the payment to be made by Buyer to Seller pursuant to Section 5.3 and as specified in **Exhibit F**.

"Environmental Contamination" means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of federal, state or local laws or regulations, or to present a material risk that as a consequence of the application of federal, state or local laws and regulations that (a) the Premises will not be available or usable for the purposes contemplated by this Agreement or (b) the potential resulting liabilities could impair Seller's ability to meet its obligations hereunder.

"**Environmental Law**" means any federal, state or local law including statutes, regulations, rulings, orders, administrative interpretations and other governmental restrictions and requirements having the force and effect of law relating to (i) the discharge or disposal of any substance into the air, soil or water, including pollutants, water pollutants or process waste water, (ii) storage, emissions transportation or disposal of any Regulated Material, (iii) the environment or hazardous substances, all as amended from time to time, (iv) land use requirements pertaining to Regulated Materials, including laws requiring environmental impact studies or other similar evaluations, and (v) environmental issues pertaining to the development, construction, operation or maintenance of the Facility.

"**Event of Default**" is defined in Section 10.1.

"**EWG**" means an "exempt wholesale generator," as defined under the Public Utility Holding Company Act of 1935, as amended from time to time.

"**Example**" means an example set forth in **Exhibit G**. Each Example is for purposes of illustration only and is not intended to constitute a representation, warranty or covenant concerning the matters assumed for purposes of each Example. If there is a conflict between an Example and the text of this Agreement, the text shall control.

"**Excused Outage**" is defined in Section 5.1.2.

"**Facility**" shall have the meaning given to that term in the **Recitals**.

"**Facility Capacity**" means the maximum Capacity of the Facility, expressed in MW, when operated consistent with the manufacturer's recommended power factor and operating parameters, as set forth in **Exhibit A**.

"**FERC**" means the Federal Energy Regulatory Commission.

"**FIN 46**" is defined in Section 6.13.

"**Force Majeure**" is defined in Section 13.1.

"**Forced Outage**" means NERC Event Types U1, U2 and U3, as set forth in **Exhibit H**.

"**Fuel**" means natural gas.

"**Governmental Authority**" means any supranational, federal, state or other political subdivision thereof, having jurisdiction over Seller, Buyer or this Agreement, including any municipality, township and county, and any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government, including any corporation or other entity owned or controlled by any of the foregoing.

"**Guaranteed Commercial Operation Date**" means ***[Bidder to insert]***.

"**Guaranteed Heat Rate**" has the meaning assigned to such term in **Exhibit Q.**

"**Guaranteed Ramp Rate**" is defined in **Exhibit Q.**

"**Guaranteed Start-Up Time**" is defined in **Exhibit Q.**

"Hazardous Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (a) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (b) petroleum, including any fraction, derivative or additive; (c) asbestos; (d) polychlorinated biphenyls; (e) radioactive material; (f) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (g) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (h) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (i) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (j) defined as a pesticide under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"**Heat Rate**" means the number of Btu's used to produce one MW of energy measured at the Delivery Point.

"**Interconnection Agreement**" means the agreement to be entered into separately between Seller and Transmission Provider providing for the construction and operation of the Electrical Interconnection Facilities.

"Lender" means any individual or entity or successor in interest thereof lending money or extending credit (including any financing lease or credit derivative arrangement) to Seller (i) for the construction, term or permanent financing or refinancing of the Facility; (ii) for working capital or other ordinary business requirements for the Facility (including for the maintenance, repair, replacement or improvement of the Facility); (iii) for any development financing, bridge financing, credit support, credit enhancement or interest rate protection in connection with the Facility; or (iv) for the purchase of the Facility and related rights from Seller. "Lender" includes a Tax Investor (as defined in the Lender Consent).

"Lender Consent" means a Consent to Collateral Assignment in favor of one or more Lenders and in substantially the form of **Exhibit T**.

"Letter of Credit" means an irrevocable standby letter of credit in form and substance acceptable to Buyer in its discretion, naming Buyer as the party entitled to demand payment and present draw requests thereunder, which letter of credit:

(1) is issued by a U.S. commercial bank or a foreign bank with a U.S. branch, with such bank having assets (net of reserves) of at least $10,000,000,000 and a Credit Rating of:

(a) "A2" or higher from Moody's; and

(b) "A" or higher from S&P;

(2) on the terms provided in the letter of credit, permits Buyer to draw up to the face amount thereof for the purpose of paying any and all amounts owing by Seller hereunder;

(3) if a letter of credit is issued by a foreign bank with a U.S. branch, permits Buyer to draw upon a U.S. branch;

(4) permits Buyer to draw the entire amount available thereunder if such letter of credit is not renewed or replaced at least thirty (30) Business Days prior to its stated expiration date;

(5) permits Buyer to draw the entire amount available thereunder if such letter of credit is not increased, replaced or replenished as and when provided in Section 7;

(6) is transferable by Buyer to any party to which Buyer may assign this Agreement under Section 17.7; and

(7) shall remain in effect for at least ninety (90) days after the end of the Term.

"Licensed Professional Engineer" means a person acceptable to Buyer in its reasonable judgment who (i) is licensed to practice engineering in the state in which the Facility is located, (ii) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion, (iii) has no economic relationship, association, or nexus with Seller, (iv) is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility, (v) is engaged by Seller on terms reasonably acceptable to Buyer, (vi) has its fees paid for by Seller, and (vii) is licensed in an appropriate engineering discipline for the required certification being made. The engagement and payment of a Licensed Professional Engineer solely to provide the certifications, evaluations and opinions required by this Agreement shall not constitute a prohibited economic relationship, association or nexus with Seller, so long as such engineer has no other economic relationship, association or nexus with Seller.

"**MAAF**" is defined in Section 5.1.2.

"**Maintenance Outage**" means NERC Event Type MO, as set forth in **Exhibit H**.

"**Major Equipment**" is defined in **Exhibit I**.

"**Major Maintenance Cycle**" means, with respect to each item of Major Equipment, the period of time specified therefor in **Exhibit I**.

"**Mediation Notice**" is defined in Section 15.2.1.

"**Minimum Monthly Capacity Payment**" is defined in Section 5.1.3.

"**Monthly Capacity Payment**" is defined in Section 5.1.2.

"**Moody's**" shall mean Moody's Investor Services, Inc.

"**MW**" means megawatt.

"**MWh**" means megawatt hour.

"**NERC**" means the North American Electric Reliability Corporation.

"**Net Energy**" means, for any period, the energy output of the Facility delivered to Buyer at the Delivery Point pursuant to Buyer's Dispatch of the Facility of a quantity in MWh not to exceed that associated with Contract Capacity, as measured pursuant to Section 8, less station use and less transformation and transmission losses to the Delivery Point.

"**Network Resource**" means a generation resource which has been fully integrated into the System.

"**Notifying Party**" is defined in Section 8.2.

"**Operating Procedures**" are set out in **Exhibit K**.

"PPT" or "**Pacific Prevailing Time**" means Pacific Standard Time or Pacific Daylight Time, as applicable on the Day in question.

"**Party**" is defined in the Preamble.

"**Peakload Capacity**" means incremental Capacity, in excess of the Baseload Capacity, which is generated by the Facility utilizing duct firing. [if applicable]

"**Permits**" means all permits, licenses, approvals, certificates, entitlements and other authorizations issued by Governmental Authorities required for the development, construction, ownership, operation and maintenance of the Facility, and all amendments, modifications, supplements, general conditions and addenda thereto.

"**Person**" means any individual, entity, corporation, general or limited partnership, limited liability company, joint venture, estate, trust, association or other entity or governmental authority.

"**Planned Outage**" means NERC Event Type PO, as set forth on **Exhibit H**.

"**Pledge Interest**" is defined in Section 7.2.2.

"**Potential Event of Default**" means an event which, but for the passing of time or the giving of notice or both, would constitute an Event of Default.

"**Premises**" means the real property on which the Facility is or will be located, as more fully described on **Exhibit A**.

"**Prime Rate**" means the rate per annum equal to the publicly announced prime rate or reference rate for commercial loans to large businesses in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.

"**Protective Apparatus**" means such equipment and apparatus, including protective relays, circuit breakers and the like, necessary or appropriate to isolate the Facility from the System consistent with Prudent Electrical Practices.

"**Prudent Electrical Practices**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts for gas fired, combined cycle electric generation facilities, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, would have been expected to accomplish the desired result in a cost efficient manner consistent with good business practices, reliability criteria, safety considerations and expediency. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

"**Reference Conditions**" means the following conditions: standard ambient air pressure at the Premises of [**?**]; ambient temperature, dry bulb, of [**?**] degrees Fahrenheit; and relative humidity of [**?**] percent ([**?**]%).

"**Regulated Materials**" means any substance, material, or waste which is now or hereafter becomes listed, defined, or regulated in any manner by any United States federal, state or local law and includes any oil, petroleum, petroleum products and polychlorinated biphenyls.

"**Remaining Capacity**" means all the Capacity of the Facility in excess of the Contract Capacity.

"**Replacement Price**" means the price at which Buyer, acting in a commercially reasonable manner, purchases for delivery at the Delivery Point a replacement for any energy that Seller is required to deliver under this Agreement, plus (i) costs reasonably incurred by Buyer in purchasing such replacement energy, and (ii) additional transmission charges, if any, reasonably incurred by Buyer in causing replacement energy to be delivered to the Delivery Point. If Buyer elects not to make such a purchase, the Replacement Price shall be the market price at the Delivery Point for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by Buyer in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

"**Reporting Month**" is defined in Section 6.9.1.

"**Requested Net Energy**" means, for any period, the Net Energy of the Facility that has been scheduled by Buyer for delivery in accordance with the Dispatch Procedures and other terms of this Agreement.

"**Required Facility Documents**" means all Permits and agreements now or hereafter necessary for the development, construction, ownership, operation and maintenance of the Facility including the documents (i) to which Seller and Buyer are a party evidencing the Security Interests and (ii) those set forth in **Exhibit C**.

"**Requirements of Law**" means collectively, as to Seller and [*if Seller is not the ultimate parent, any ultimate parent entity*], Seller's organizational or governing documents and any federal, state, county or municipal, law, treaty, ordinance, franchise, rule, regulation, order, writ, judgment, injunction, decree, award or determination of any arbitrator, or a court or other Governmental Authority, in each case, now or hereafter applicable to or binding upon this Agreement, the Facility, Seller or [*if Seller is not the ultimate parent, any parent entity*] to which any of their respective properties are subject (including those pertaining to electrical, building, zoning, environmental and occupational health and safety).

"**RTO**" means any person, other than Transmission Provider, that becomes responsible as system operator for, or directs the operation of, the System.

"**S&P**" shall mean Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.).

"**Schedule**" or "**Scheduled**" means the acts of Buyer and Seller pursuant to Section 6.5 setting forth a schedule requesting and accepting the delivery of energy by Seller to Buyer on and after the Commercial Operation Date.

"**Scheduling Constraints**" means the limitations of the Facility's Capacity arising as a result of the need to observe the physical ramp rates of the Major Equipment and maintain minimum run times, minimum down times, minimum dispatch levels of Net Energy and Capacity per CT, and maximum levels of Net Energy and Capacity, to be generated by any item of Major Equipment, in compliance with the warranty requirements relating to each item of

Major Equipment, the operating and maintenance standards recommended by the Facility's equipment suppliers, and Prudent Electrical Practice, as set forth on **Exhibit P**.

"**Scheduling Fees**" means fees assessed by any person to schedule the delivery of the energy.

"**Security Interests**" is defined in Section 7.2.1.

"**Seller**" is defined in the Preamble.

"**Senior Lenders**" means the Lenders providing construction financing for the Facility, or any term or permanent take-out financing of such construction financing, that are not Affiliates of Seller.

"**Simple Cycle**" means operation of a Combustion Turbine without capturing the waste heat from the Combustion Turbine in the associated heat recovery steam generator and, therefore, without producing additional Net Energy from the steam turbine utilizing steam produced by such heat recovery steam generator. When one or more CTs are operated in Simple Cycle mode, the Facility will produce less Capacity and less Net Energy, while consuming Fuel at a higher heat rate, than when the Facility is operated in combined cycle mode to produce Baseload Capacity. The ramp rates applicable to each CT, as set forth in **Exhibit Q**, are faster in Simple Cycle mode than in combined cycle mode.

"**Solvency**" or "**Solvent**" is defined in Section 3.2.12.

"**Standard Heat Rate**" means the actual Heat Rate of the Facility at varying levels of the Net Energy and varying ambient conditions.

"**Start-Up**" means a firing of one or more of the items constituting Major Equipment when such item or items of Major Equipment is not being operated, including any firing required to perform a CT Start. The period of a Start-Up of any item of Major Equipment begins at the commencement of such firing and ends when such item of Major Equipment obtains and produces on a continuous basis the desired quantity of Net Energy.

"**Start-Up Testing**" means the tests set in **Exhibit E**.

"**System**" means the electric transmission sub-station and distribution facilities owned, operated or maintained by Transmission Provider, which shall include, after construction and installation of the Facility, the circuit reinforcements, extensions, and associated terminal facility reinforcements or additions required to complete the Facility, all as set forth in the Interconnection Agreement.

"**Tariff**" means Buyer's FERC Electric Tariff Fourth Revised Volume No. 11 Pro Forma Open Access Transmission Tariff, as revised from time to time.

"**Term**" is defined in Section 2.1.

"**Transmission Provider**" means [*PacifiCorp, an Oregon corporation, acting in its transmission function capacity*.] [*Note to Bidders: If the Facility is interconnected to another system, identify the appropriate Transmission Provider.*] Seller acknowledges that Buyer, as Buyer under this Agreement, has no responsibility for or control over such Transmission Provider.

"**Unexcused Outage**" is defined in Section 5.1.2.

"**Unplanned Outage**" means NERC Event Type U, as set forth on **Exhibit H**.

"WECC" means the Western Electricity Coordinating Council.

1.2 Rules of Interpretation.

1.2.1 General. Terms used in this Agreement but not specifically defined in this Section 1 shall have meanings as commonly used in the English language and, where applicable, in Prudent Electrical Practices. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used in accordance with such recognized meanings. Unless otherwise required by the context in which any term appears, (a) the singular shall include the plural and vice versa; (b) references to "Articles," "Sections," "Schedules," "Annexes," "Appendices" or "Exhibits" (if any) shall be to articles, sections, schedules, annexes, appendices or exhibits of this Agreement; (c) all references to a particular entity or an electricity market price index shall include a reference to such entity's or index's successors and (if applicable) permitted assigns; (d) the words "herein," "hereof" and "hereunder" shall refer to this Agreement as a whole and not to any particular section or subsection hereof; (e) all accounting terms not specifically defined in this Agreement shall be construed in accordance with generally accepted accounting principles in the United States of America, consistently applied; (f) references to this Agreement shall be deemed to include a reference to all appendices, annexes, schedules and exhibits hereto, as the same may be amended, modified, supplemented or replaced from time to time; (g) the masculine shall include the feminine and neuter and vice versa; (h) the word "including" shall be construed in its broadest sense to mean "without limitation" or "but not limited to" and (i) the word "or" is not necessarily exclusive.

1.2.2 Terms Not to Be Construed for or Against Either Party. Each term of this Agreement shall be construed simply according to its fair meaning and not strictly for or against either Party. The Parties have jointly prepared this Agreement, and no term of this Agreement shall be construed against a Party on the ground that the Party is the author of that provision.

1.2.3 Headings. The headings used for the sections of this Agreement are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions of this Agreement.

1.2.4 Interpretation with FERC Orders. Each Party conducts its operations in a manner intended to comply with FERC Order No. 717, Standards of Conduct for Transmission Providers, requiring the separation of its transmission and merchant functions. Moreover, the Parties acknowledge that each of Transmission Provider's and Interconnection Provider's transmission function offers transmission service on its System in a manner intended to comply with FERC policies and requirements relating to the provision of open-access transmission service. The Parties recognize that Seller will enter into the separate Interconnection Agreement.

1.2.4.1 The Parties acknowledge and agree that the Interconnection Agreement shall be a separate and free standing contract and that the terms of this Agreement are not binding upon Transmission Provider.

1.2.4.2 Notwithstanding any other provision in this Agreement, nothing in the Interconnection Agreement, nor any other agreement between Seller on the one hand and Transmission Provider or Interconnection Provider on the other hand, nor any alleged event of default thereunder, shall alter or modify the Parties' rights, duties, and obligations under this Agreement. This Agreement shall not be construed to create any rights between Seller and Transmission Provider.

1.2.4.3 Seller expressly recognizes that, for purposes of this Agreement, Transmission Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Transmission Provider or an Affiliate thereof. Seller acknowledges that PacifiCorp, acting in its merchant capacity function as purchaser hereunder, has no responsibility for or control over Interconnection Provider or Transmission Provider, and is not liable for any breach of agreement or duty by Interconnection Provider or Transmission Provider.

SECTION 2

TERM; COMMENCEMENT OF OPERATION

2.1 Term. This Agreement shall become effective when it is signed and delivered by both Parties (the "**Effective Date**") and, unless earlier terminated as provided in this Agreement, shall remain in effect until the **[?]** anniversary of the Commercial Operation Date (the "**Term**").

2.2 Milestones. Time is of the essence of this Agreement, and Seller's ability to meet certain milestones before the Commercial Operation Date and to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date is critically important. Therefore, Seller shall achieve the following milestones unless waived or extended by Buyer in its sole and absolute discretion: [***Note to bidders: portions of this Section 2.2 may not be applicable to a non-facility dependent contract***]

2.2.1 By [*date*], Seller shall demonstrate to Buyer's reasonable satisfaction that Seller has made all arrangements and obtained all means for transporting Fuel in quantities sufficient to operate the Facility at the Facility Capacity for the Term;

2.2.2 By [*date*], Seller shall obtain and provide to Buyer copies of all Required Facility Documents necessary for construction of the Facility;

2.2.3 By [*date*], Seller shall provide to Buyer evidence acceptable to Buyer that Seller has obtained construction financing for the Facility (or alternatively permanent financing subject only to construction of the Facility and Seller's execution of the lender's loan documents);

2.2.4 By [*date*], Seller shall provide Buyer with an As-built Supplement acceptable to Buyer;

2.2.5 By [*date*], Seller shall begin deliveries of Net Energy for purposes of initiating Start-Up Testing; and

2.2.6 By the Guaranteed Commercial Operation Date, the Commercial Operation Date shall have occurred. This shall require that all of the following conditions shall have been satisfied or waived by Buyer in its sole and absolute discretion:

(1) Buyer shall have received a certificate addressed to Buyer from a Licensed Professional Engineer certifying that the Facility is able to generate energy reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

(2) Start-Up Testing of the Facility shall have been completed;

(3) After Buyer has received notice of the completion of Start-Up Testing, Buyer shall have endorsed a certificate addressed to Buyer from a Licensed Professional Engineer certifying that the Facility has operated for testing purposes under this Agreement uninterrupted for a period of ten (10) consecutive days at a rate of at least the Facility Capacity based upon any sixty (60) minute period for the entire testing period. Seller must provide five (5) Business Days' written notice to Buyer before the start of the Start-Up Testing period. If the operation of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall start a new consecutive ten (10) day testing period and Seller shall provide Buyer forty-eight (48) hour written notice before the start of such testing period;

(4) Buyer shall have received a certificate addressed to Buyer from a Licensed Professional Engineer certifying that, in accordance with the Interconnection Agreement, all required Electrical Interconnection Facilities have been constructed, all required interconnection tests have been completed, the Facility is physically interconnected and is fully interconnected, fully integrated, and fully synchronized with the System and the Facility Capacity is a Network Resource;

(5) Buyer shall have received a certificate addressed to Buyer from a Licensed Professional Engineer, and, with respect to legal matters, an opinion from counsel acceptable to Buyer in the reasonable exercise of its discretion, certifying that Seller has obtained all Required Facility Documents for the construction and operation of the Facility and, if requested by Buyer in writing, Seller shall have provided copies of any or all such requested Required Facility Documents, together with (i) the certificates of insurance coverage or insurance policies required by Section 12.1, and (ii) copies of all Required Facility Documents which Seller is responsible to obtain or are required for the construction and operation of the Facility;

(6) Buyer shall have issued a written certificate to Seller certifying that Buyer has received all Facility drawings, plans, specifications, policies, and other documents required by this Agreement;

(7) Buyer shall have received a certificate addressed to Buyer from Seller's primary construction contractor certifying that the Facility has been turned over to Seller for permanent operation and maintenance and that the primary construction contractor owes no further construction-related obligations to Seller (other than punch list items); and

(8) Buyer shall have received a certificate addressed to Buyer from an office of Seller and acceptable to Buyer certifying that no Event of Default by Seller or Potential Event of Default by Seller exists under this Agreement.

2.3 Daily Delay Damages. Seller shall cause the Commercial Operation Date to occur on or before the Guaranteed Commercial Operation Date but no earlier than **[*? months*]** prior to the Guaranteed Commercial Operation Date. If the Commercial Operation Date does not occur on or before the Guaranteed Commercial Operation Date, to compensate Buyer for the failure to provide energy and Capacity from the Facility, Seller shall pay Buyer delay damages equal to the Daily Delay Damages times Contract Capacity for each Day or portion of a Day until that Day that the Commercial Operation Date occurs from and after the Guaranteed Commercial Operation Date. Each Party agrees and acknowledges that (a) the damages that Buyer would incur for the failure to provide energy from the Facility due to delay in achieving the Commercial Operation Date on or before the Guaranteed Commercial Operation Date would be difficult or impossible to predict with certainty, and (b) the Daily Delay Damages mech nism is an appropriate approximation of such damages. This Section 2.3 shall not limit the amount of damages payable to Buyer if this Agreement is terminated as a result of Seller's failure to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date and any such damages shall be determined in accordance with Section 10.7. In addition, this Section 2.3 shall not limit the damages payable to Buyer for matters resulting from delay in achieving the Commercial Operation Date other then the failure to provide energy from the Facility.

2.4 Damages Invoicing. By the tenth (10th) day following the end of the calendar month of the Guaranteed Commercial Operation Date, and continuing on the tenth (10th) day following the end of any calendar month during which Daily Delay Damages are incurred, Buyer shall deliver to Seller a proper invoice showing Buyer's computation of such damages and any amount due Buyer in respect thereof for the preceding calendar month. No later than ten (10) days after receiving such an invoice, Seller shall pay to Buyer, by wire transfer of immediately available funds to an account specified in writing by Buyer or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice.

2.5 Buyer's Right to Monitor. During the design, procurement, construction, installation, start up and testing of the Facility, Seller shall permit Buyer and its advisors and consultants to:

(a) Review and discuss with Seller and its advisors and consultants monthly status reports on the progress of the development, design, construction and installation of the Facility. Between the date on which this Agreement is executed and thirty (30) days following the Commercial Operation Date, Seller shall, on or before the tenth (10^{th}) day of each calendar month, provide Buyer with a brief monthly status report for the preceding month.

(b) Monitor the development, design, engineering, procurement, construction and installation of the Facility and the performance of the contractors constructing the Facility. Nothing in this Agreement shall be construed to require PacifiCorp to review, comment on, or approve of any contract between Seller and a third party.

(c) Review and monitor the progress of Seller's negotiation and execution of contracts and the contractors' performance and achievement of (i) all initial performance tests and other tests required under the Facility construction contracts that must be performed in order to achieve the Commercial Operation Date and (ii) all tests contemplated by the warranty agreements between Seller and manufacturer of the Facility's CTs and any other Major Equipment. Buyer reserves the right to require additional performance tests of the Facility's CTs in the event that Seller elects not to have such CTs or other Major Equipment covered by warranty agreements acceptable to Buyer. Seller shall provide Buyer with at least five (5) Business Days' prior notice of each such test.

(d) Witness initial performance tests and other tests and review the results thereof.

(e) Perform such examinations, inspections, and quality surveillance as, in Buyer's reasonable judgment, are appropriate and advisable to determine that all Major Equipment comprising the Facility has been properly commissioned and that the Facility has achieved the Commercial Operation Date.

The Parties acknowledge and agree that Buyer is under no obligation to perform any of the monitoring rights under this Section 2.5. Any information or knowledge obtained by Buyer in the exercise of its rights under this Section 2.5 shall not prevent Buyer from subsequently asserting that Seller failed to perform its obligations under this Agreement or failed to satisfy any of its conditions in Section 2, nor shall the exercise by Buyer of such rights be used as evidence that Seller performed its obligations under this Agreement or satisfied its conditions in Section 2 or that Buyer gave any consent to Seller's action in meeting its obligations under Section 2. Buyer's right to indemnification, payments for damages or other remedy in this Agreement will not be affected by any investigation conducted with respect to, or any knowledge acquired (or capable of being acquired) at any time, whether before or after the execution and delivery of this Agreement or the Commercial Operation Date, including with respect to the accuracy or inaccuracy of any representation or warranty, or compliance with any covenant or obligation hereunder. Buyer shall maintain one or more designated representatives for purposes of the monitoring activities contemplated in this Section 2.5, which representatives shall have authority to act for Buyer in all technical matters under this Section 2.5. However, Buyer's representatives, in their capacity as representatives, shall not have the authority to amend or modify any provision of this Agreement. Buyer's initial representatives for purposes of this Section 2.5 and their contact information are listed in **Exhibit N**. Buyer may, by written notice to Seller, change its representatives or the contact information for such representatives.

SECTION 3

REPRESENTATIONS AND WARRANTIES

3.1 Buyer's Representations and Warranties. Buyer represents, covenants, and warrants to Seller that:

3.1.1 Organization. Buyer is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 Authority. Buyer has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 Corporate Actions. Buyer has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 No Contravention. The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Buyer or any valid order of any court, or any regulatory agency or other body having authority to which Buyer is subject.

3.1.5 Valid and Enforceable Agreement. This Agreement is a valid and legally binding obligation of Buyer, enforceable against Buyer in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller's Representations and Warranties. Seller represents, covenants, and warrants to Buyer that:

3.2.1 Organization. Seller is a [***insert legal entity***] duly [***organized***] and validly existing under the laws of [______].

3.2.2 Authority. Seller (i) has the requisite power and authority to enter into this Agreement and to perform, including all required regulatory authority to make wholesale sales from the Facility; (ii) has the power and authority to own and operate its businesses and properties, to own or lease the property it occupies and to conduct the business in which it currently engaged; and is duly qualified as [____] in Utah; and (iii) is in good standing under the laws of each jurisdiction where its ownership, lease or operation of property or the conduct of its business requires such qualification.

3.2.3 Actions. Seller has taken all [***insert appropriate legal entity***] actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 No Contravention. The execution, delivery, performance and observance by Seller of its obligations under this Agreement do not and will not:

3.2.4.1 contravene, conflict with or violate any provision of any material Requirements of Law presently in effect having applicability to either Seller or [***if Seller is not the ultimate parent, Seller's ultimate parent***];

3.2.4.2 require the consent or approval of or material filing or registration with any Governmental Authority or other person other than such consents and approvals which are (i) set forth in **Exhibit C** or (ii) required in connection with the construction or operation of the Facility and expected to be obtained in due course;

3.2.4.3 result in a breach of or constitute a default under any provision of any security issued by [***ultimate parent of Seller***] or any of its Affiliates or any material agreement, instrument or undertaking to which either [***ultimate parent of Seller***] or any of its Affiliates is a party or by which [***ultimate parent of Seller***]**'s** or any of its Affiliates' property is bound; or

3.2.4.4 require Seller to be licensed under the Utah Construction Trades Licensing Act.

3.2.5 Valid and Enforceable Agreement. This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 Litigation. No litigation, arbitration, investigation or other proceeding is pending or, to the best of Seller's knowledge, threatened against either Seller, its parents, or any Affiliate with respect to this Agreement and the transactions contemplated hereby and thereby.

3.2.7 Accuracy of Information. To the knowledge of Seller, no exhibit, contract, report or document furnished by Seller to Buyer in connection with this Agreement, or the negotiation or execution of this Agreement contains any material misstatement of fact or omits to state a material fact or any fact necessary to make the statements contained therein not misleading.

3.2.8 Required Facility Documents. All Required Facility Documents are set forth in **Exhibit C** attached hereto. To Seller's knowledge, no unusual or burdensome conditions are expected by Seller to be placed upon, or created by, any of the Required Facility Documents. The anticipated use of the Facility complies with all applicable restrictive covenants affecting the Premises and all Requirements of Law. The representation made in this Section 3.2.8 shall be deemed to be given throughout the entire Term.

3.2.9 Taxes. Seller has filed or caused to be filed all tax returns which were required to be filed and has paid all taxes shown to be due and payable on said returns or on any assessments made against it or any of its property including the Premises, and all other taxes, fees or other charges imposed on it or any of its property by any Governmental Authority, and no tax liens have been filed and no claims are being asserted with respect to any such taxes, fees or other charges, except where such taxes, fees or other charges are being contested in good faith by Seller through appropriate proceedings with adequate reserves set aside in the event of an adverse determination.

3.2.10 Seller's Intent. Seller intends:

3.2.10.1 To construct and operate the Facility in accordance with Prudent Electrical Practices, and in accordance with, and subject to the terms of this Agreement;

3.2.10.2 To supply the Contract Capacity and Net Energy of the Facility throughout the Term of this Agreement in accordance with the provisions of this Agreement; and

3.2.10.3 [***if Seller will be a single purpose vehicle, that its sole business shall be the ownership and operation of the Facility***.]

3.2.11 No Collusion. Neither Seller nor any of its representatives has e tered into any form of collusive arrangement with any person or entity which directly or indirectly has to any extent lessened competition between Seller and any other person or entity for the supply of Capacity and energy sought by Buyer.

3.2.12 Solvency. Seller, its parents and their Affiliates are Solvent. "**Solvent**" and "**Solvency**" means with respect to any person or entity on any date of determination, that on such date (a) the book value of the property of such person or entity is greater than the total amount of book liabilities, including contingent liabilities that are probable and estimable, of such person or entity, (b) such person or entity is able to pay its debts as they become absolute and matured, taking into account the possibility of refinancing such obligations and selling assets, (c) such person or entity does not intend to, and does not believe that it will, incur debts or liabilities beyond such person's or entity's ability to pay such debts and liabilities as they mature taking into account the possibility of refinancing such obligations and selling assets and (d) such person or entity is not engaged in business or a transaction, and is not about to engage in business or a transaction, for which such person's or entity's property would constitute an unreasonably small capital. The amount of contingent liabilities at any time shall be computed as the amount that are probable and estimable in the light of all the facts and circumstances existing at such time, and that can reasonably be expected to become an actual or matured liability.

3.3 Notice. If at any time during the Term, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties made by it in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with notice in accordance with Section 17.12 of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section 3 shall be given as soon as practicable after the occurrence of each such event.

SECTION 4

SALE AND PURCHASE OBLIGATIONS

4.1 Sale and Purchase of Contract Capacity, Capacity Rights, Net Energy and Ancillary Services.

4.1.1 Subject to the terms and conditions of this Agreement, on and after the Commercial Operation Date and for the balance of the Term, Seller shall make available to Buyer from the Facility the Contract Capacity and the Capacity Rights, and all Net Energy and Ancillary Services associated with such Contract Capacity that is Scheduled by Buyer for delivery in accordance with the Dispatch Procedures and Section 6.5.2.

4.1.2 Subject to Section 5.1, Buyer shall purchase the Contract Capacity of the Facility and pay a monthly Capacity Payment to Seller.

4.1.3 Seller shall provide Ancillary Services and Capacity Rights to Buyer without additional charge or expense.

4.1.4 Buyer shall be under no obligation to purchase any Capacity under this Agreement other than Contract Capacity. Buyer has or may in the future have certain planning, operating and reporting requirements with an Electric System Authority, and Seller shall cooperate with Buyer in connection therewith.

4.1.5 Buyer shall pay the amounts specified in Section 5, and Seller shall then provide to Buyer without additional charge or expense all Net Energy and Ancillary Services that have been Scheduled by Buyer.

4.1.6 Seller shall provide to Buyer from the Facility the Contract Capacity, and associated quantities of Net Energy or Ancillary Services as Scheduled by Buyer in accordance with this Agreement. Subject to Section 4.3, the Contract Capacity, and the Net Energy and Ancillary Services associated with such Contract Capacity, shall be made available exclusively to Buyer and Seller shall be free to sell the Remaining Capacity of the Facility, and the Net Energy and Ancillary Services associated with such Remaining Capacity, to any third party. Seller shall have absolute discretion over the operation of the Facility to generate the quantities of Capacity, Net Energy and Ancillary Services to be delivered to Buyer in compliance with the provisions of this Agreement. In addition, Seller shall have absolute discretion over the use of the Remaining Capacity in sales to any third parties.

4.2 Deliveries; Title and Risk of Loss. All Net Energy and Ancillary Services that have been, at Buyer's option, Scheduled by Buyer shall be delivered by Seller to Buyer at the Delivery Point. Seller shall be deemed to be in exclusive control of, and responsible for any damage or personal injury caused by, Net Energy or Ancillary Services delivered hereunder up to the Delivery Point; and Buyer shall be deemed to be in exclusive control of, and responsible for any damages or injury caused by, such Net Energy or Ancillary Services from the Delivery

Point. Seller warrants and agrees that it will transfer and deliver Contract Capacity, Capacity Rights, Ancillary Services and Net Energy to Buyer free and clear of all liens or other encumbrances and rights of third parties. Title to and risk of loss of all Net Energy or Ancillary Services shall transfer from Seller to Buyer upon delivery to Buyer at the Delivery Point. Buyer's purchase of Capacity Rights in no way represents any purchase of equity or ownership rights of any kind in Seller or the Facility.

4.3 <u>Dispatching Deliveries from the Contract Capacity versus the Remaining Capacity</u>.

4.3.1 Seller shall exclusively make available to Buyer the Contract Capacity of the Facility, and Seller shall deliver to Buyer, and Buyer shall receive, the quantities of Net Energy and Ancillary Services that were Scheduled by Buyer from such Contract Capacity in accordance with this Agreement. Subject to Section 4.3.1, Seller retains absolute discretion as to which items of the Major Equipment of the Facility are operated to generate and deliver (i) the quantities of Net Energy and Ancillary Services to be delivered to Buyer from the Contract Capacity and (ii) the quantities of Net Energy and Ancillary Services to be delivered to any third party purchaser from the Remaining Capacity.

4.3.2 During any Excused Outage or Unexcused Outage of the Facility, as defined in Section 5.1.2, which causes a partial outage of the Facility, but not a complete shutdown of the Facility, Buyer's right to the Contract Capacity shall not be affected by any reduction in the Facility Capacity, and to the extent there is a reduction of Facility Capacity, Seller shall make available to Buyer all of such reduced Facility Capacity up to the Contract Capacity. Subject to the foregoing, Seller shall, at all times, have the right to make available for sale to any third party purchasing any of the Remaining Capacity no more than the actual available Capacity of the Facility less the Contract Capacity.

4.3.3 At any time that the Contract Capacity is available, Buyer may elect to Schedule any of the quantities of Net Energy, and equivalent quantities of Ancillary Services, specified in the range of dispatchable quantities of Net Energy on **Exhibit P**.

4.4 <u>Curtailment Due to Failure to Comply with Interconnection Agreement</u>. Buyer shall not be obligated to purchase Contract Capacity or receive or pay for Net Energy to the extent generation or transmission curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or because (a) the interconnection between the Facility and the System is disconnected, suspended or interrupted, in whole or in part, pursuant to the terms of the Interconnection Agreement, (b) the Transmission Provider curtails Net Energy, (c) the Facility's Net Energy is not received because the Facility is not fully integrated or synchronized with the System or (d) an event of Force Majeure prevents either Party from delivering or receiving Net Energy. Nothing in this Section 4.4 shall relieve Seller of its duty to comply with the Interconnection Agreement and Net Energy curtailed as provided under this Section 4.4 shall not be deemed to be an Excused Outage, or credited toward the achievement of Net Energy, as the case may be.

4.5 <u>Sale of Test Energy</u>. During the period between the Effective Date and the Commercial Operation Date, Seller shall sell and make available to Buyer, and Buyer shall purchase and accept, all energy produced by the Facility during such period (the "**Test Energy**") at the price provided in Section 5.3.

SECTION 5

PAYMENTS; COSTS

5.1 Capacity Payments. Commencing on the last day of the month in which the Commercial Operation Date occurs, Buyer shall, subject to Section 5.1.4, pay to Seller in arrears a Capacity Payment equal to the greater of (i) the Monthly Capacity Payment as determined in Section 5.1.2, or (ii) the Minimum Monthly Capacity Payment as determined in Section 5.1.3.

5.1.1 All Capacity Payments shall be billed on a calendar month basis. In the event that Commercial Operation Date does not occur at the start of a calendar month, the first month's Capacity Payment shall be prorated to reflect the actual number of days of Commercial Operation in such month.

5.1.2 Monthly Capacity Payment. The "**Monthly Capacity Payment**" shall be computed based upon the following formula:

Monthly Capacity Payment = (CC × 1000 × CPR × MAAF) - CPS, where:

CC = the Contract Capacity;

CPR = Capacity Payment Rate;

CPS = Capacity Payment Shortfall, if any from any prior month; and

MAAF = Availability Adjustment Factor for that month, computed as follows:

a. If CAF_m = [Bidder to insert %], MAAF = 1

b. If CAF_m < [Bidder to insert %], MAAF = 1 - 2 x ([Bidder to insert] - CAF_m)

Provided, *however*, MAAF cannot be less than zero (0).

CAF_m = Average Capacity Availability Factor for a month shall equal the sum of the hourly Capacity Availability Factors ("**CAF_h**") determined for each hour of such month, divided by the total number of hours in such month; and

CAF_h = (AD + DD) / AFCE

Provided, *however*, CAF_h cannot be more than one (1).

where:

“**AD**” (Actual Deliveries) means, for any hour, the actual quantity of energy generated by the Facility and delivered by Seller to Buyer at the Delivery Point;

“**DD**” (Deemed Deliveries) means, for any hour, (i) a quantity of energy equal to the amount of energy that could have been generated by that portion of the Ambient Facility Capacity that was set forth in the Availability Notice (a) that was not dispatched by Buyer in such hour, (b) that was not generated and delivered due to a Potential Event of Default or an Event of Default by Buyer, or (c) that was not operated to generate and deliver Net Energy or Ancillary Services to Buyer due to any failure by Buyer; (ii) any amount of energy that was not available from the Facility for dispatch and receipt by Buyer, during the relevant hour, due to any outage or derating that meets the requirements for Scheduled Maintenance established in **Exhibit I**; and (iii) any amount of energy that was not available from the Facility for Dispatch and receipt by Buyer, during the relevant hour, due to any Force Majeure event. The unavailability of Capacity for any of the reasons set forth in clauses (i)(c), (ii) or (iii) shall be considered an “**Excused Outage**.” To the extent that the Capacity of the Facility, up to the Contract Capacity, is unavailable to Buyer for any reason other than an Excused Outage shall be considered an “**Unexcused Outage**.”

“**AFCE**” (Ambient Facility Capacity Energy) means the quantity of energy that could be produced from the Ambient Facility Capacity during such hour.

5.1.3 Minimum Monthly Capacity Payment. During any month, the “**Minimum Monthly Capacity Payment**” shall equal the amount determined by the following formula:

Minimum Monthly Capacity Payment = CC × 1000 × CPR × **[?%]**, where:

CC = the Contract Capacity;

CPR = Capacity Payment Rate; and

% = **[?]**.

5.1.4 Carry-Over Provisions. With respect to any month in which the calculated Monthly Capacity Payment is less than the Minimum Monthly Capacity Payment, the difference between the two payment amounts shall be set forth in a separate account (the amount in such account is referred to herein as the “**Capacity Payment Shortfall**”). The Capacity Payment Shortfall shall be increased by interest at the Prime Rate divided by 365 on the maximum amount of the Capacity Payment Shortfall on that day and shall be recovered by Buyer as a credit against the otherwise applicable Monthly Capacity Payment owed to Seller in any following month and by drawing on the Carry-Over-Letter of Credit as provided below. That portion of any Capacity Payment Shortfall which is not recovered in any month shall be carried over to each subsequent month thereafter until recovered by Buyer in full from Seller. If the Capacity Payment Shortfall exceeds $**[?]**, then Seller shall provide a Letter of Credit for the benefit of Buyer, in form reasonably acceptable to Buyer, with a face amount equal to the full amount of the Capacity

Payment Shortfall amounts ("**Carry-Over Letter of Credit**"). The amount of such Carry-Over Letter of Credit shall be adjusted thereafter, at the end of each month, to equal the then-outstanding Capacity Payment Shortfall. At the end of each Contract Year, Buyer shall be entitled to draw down against the Carry-Over Letter of Credit for the amount the Capacity Payment Shortfall that has not been recovered as of that date.

5.2 Energy Payment. Commencing on the last day of the month in which the Commercial Operation Date occurs, Buyer shall pay to Seller in arrears an Energy Payment as set forth in **Exhibit F** for Net Energy. Unless directly specified on Exhibit F, in no event shall the Energy Payment be increased during the term hereof on account of any action by any Governmental Authority, including the imposition of a fee, tax or requirement of allowances for the emission of greenhouse gases.

5.3 Test Energy. For the period between the Effective Date and the Commercial Operation Date, Seller shall sell and deliver Net Energy to Buyer at the Delivery Point as Test Energy. Buyer shall pay Seller for Test Energy delivered at the Delivery Point, an amount per MWh equal to eighty-five percent (Bidder to insert %) of the settled price for the applicable hour in the daily (i) firm on-peak, (ii) firm-off peak or (iii) 24-hour firm (on Sundays and NERC holidays) Dow Jones™ SP15 Electricity Price Index; *provided*, *however*, that the amount to be paid by Buyer for such Test Energy shall in no event exceed seventy-five percent (75%) of the price per MWh specified on **Exhibit M** for the first Contract Year. If the Dow Jones™ SP15 Electricity Price Index ceases to be published during the Term, Buyer shall select as a replacement electricity price index or component, an index acceptable to Buyer in its discretion that, after any necessary adjustments, provides the most reasonable substitute quotation of the daily price of firm on-peak, firm off-peak or 24-hour firm energy at South of Path 15 for the applicable periods.

5.4 Costs and Charges. Seller shall be responsible for all costs or charges imposed in connection with the delivery of Net Energy at the Delivery Point, including transmission costs and charges. Without limiting the generality of the foregoing, except to the extent otherwise provided in the Interconnection Agreement, Seller shall bear all costs associated with the modifications to Transmission Provider's interconnection facilities or electric system (including system upgrades) caused by or related to (a) the interconnection of the Facility with Transmission Provider's system, (b) any increase in Capacity of the Facility, and (c) any increase of delivery of energy from the Facility.

5.5 Station Service. Seller shall be responsible for arranging and obtaining, at its sole risk and expense, any station service required by the Facility and electric energy for any other activities occurring on the Premises or prior to the low side of the substation of the Interconnection Facilities.

SECTION 6

OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of construction of the Facility, Seller shall provide Buyer the As-built Supplement. The As-built Supplement shall be deemed effective and shall be added to **Exhibit A** of this Agreement when it has been reviewed and approved by Buyer. Buyer shall not unreasonably withhold, condition or delay its approval of the As-built Supplement.

6.2 Measurement and Quality of Net Energy. All Net Energy shall be measured at the Delivery Point and shall meet all requirements in the Interconnection Agreement and the specifications set forth in **Exhibit P**. Seller shall instruct the Transmission Provider in writing that Buyer is entitled to receive, directly from Transmission Provider, any and all data associated with the Facility or the production of Net Energy that the Transmission Provider has in its possession.

6.3 Standard of Facility Operation.

6.3.1 General.

6.3.1.1 At Seller's sole cost and expense, Seller shall operate, maintain and repair the Facility and the Electrical Interconnection Facilities in accordance with (i) the standards, criteria and formal guidelines of all Electric System Authorities and any successors to the functions thereof; (ii) the Required Facility Documents; (iii) the Interconnection Agreement; (iv) all Requirements of Law; (v) the requirements of this Agreement; and (vi) Prudent Electrical Practice. During the Term, Seller shall be the sole owner of the Electrical Interconnection Facilities. Seller shall defend, indemnify and hold Buyer harmless from and against any requirements to comply with FERC Open Access requirements respecting the Electrical Interconnection Facilities caused by Seller's act or omission. Seller acknowledges that it shall have no claims under this Agreement against Buyer, acting in its merchant function capacity, with respect to any requirements imposed by or damages caused by Buyer, acting in its transmission function capacity, in connection with the Interconnection Agreement or otherwise.

6.3.1.2 Without limiting the generality of Section 6.3.1.1, Seller shall:

6.3.1.2.1 At all times, employ qualified and trained personnel for managing, operating and maintaining the Facility and for coordinating such managing, operating and maintenance with Buyer. Seller shall ensure that prior to or on the first Day Seller delivers energy to the Delivery Point such qualified and trained personnel are available to Buyer at all times, twenty-four (24) hours per Day during the Term.

6.3.1.2.2 Operate and maintain the Facility with due regard for the safety, security and reliability of the System and Buyer's customers and in compliance with the general specifications contained in **Exhibit I**.

6.3.1.2.3 Comply with operating and maintenance standards recommended by the Facility's equipment suppliers.

6.3.1.2.4 Coordinate the Facility's relaying and protection to conform with Prudent Electrical Practice.

6.3.1.2.5 Furnish and install, at Seller's sole expense, a manually operable disconnecting device that can be locked by Buyer in the open position and visually checked to be in the open position, so as to be able to electrically isolate the Facility from the System. This device shall be installed at a location at or near the Delivery Point.

6.3.1.2.6 Have the Facility's protective relays calibrated and operationally checked, at least annually by a person qualified to perform such service and provide Buyer with a written confirmation of the calibration.

6.3.1.2.7 Operate the Facility in such a manner so as not to have an adverse effect on Buyer's voltage level or voltage waveform.

6.3.1.2.8 Operate the Facility in a manner and consistent with the Operating Procedures so as to permit Buyer to dispatch individuals items of Major Equipment required to generate energy Scheduled by Buyer.

6.3.2 Interconnection. Pursuant to the Interconnection Agreement, Seller shall be responsible for the costs and expenses associated with interconnection of the Facility at its Facility Capacity at the Delivery Point, including the costs of any System upgrades beyond the Delivery Point necessary to interconnect the Facility with System and to allow the delivery of energy to the Delivery Point.

6.3.3 Coordination with System. Pursuant to the Interconnection Agreement, Seller shall be responsible for the coordination and synchronization of the Facility's equipment with the System, and shall be solely responsible for (and shall defend and hold Buyer harmless against) any damage that may occur as a direct result of Seller's improper coordination or synchronization of such equipment with the System.

6.4 Operating Procedures and Compliance.

6.4.1 Without limiting the generality of Section 6.2, during the Term, the Parties shall observe the Operating Procedures.

6.4.2 In the Operating Procedures, each Party has designated an authorized representative (an "**Authorized Representative**") and an alternate representative (an "**Alternate Representative**") to act in the Authorized Representative's absence. A Party's appointment of an Authorized Representative and Alternate Representative shall remain in full force and effect until the Party delivers written notice of substitution to the other Party. The Authorized Representatives and Alternate Representatives shall be managers well-experienced with regard to matters relating to the implementation of the Parties' rights and obligations under this Agreement.

6.4.3 Operational Compliance.

6.4.3.1 Required Facility Documents. Seller shall maintain in full force and effect and available for inspection by Buyer during the Term all Required Facility Documents now or hereafter required.

6.4.3.2 Hazardous Substances. Seller shall operate the Facility in compliance with all Environmental Laws and permits, licenses, rules or orders promulgated, issued or otherwise required by a Governmental Authority having jurisdiction or enforcement power over any Environmental Law and Seller. Seller shall immediately notify Buyer if Seller or any Affiliate of Seller receives or obtains any actual knowledge of or actual notice of any past, present or future actions or plans which may interfere with or prevent compliance or continued compliance with Environmental Laws, affect the construction or operation of the Facility, or may give rise to any material liability under any Environmental Laws or to any common law or legal liability or otherwise form the basis of any claim, action, demand, suit, proceeding, hearing, study or investigation under Environmental Laws.

6.4.4 Taxes. Seller shall pay when due or reimburse Buyer for all existing and any new sales, use, excise, ad valorem, and any other similar taxes, imposed or levied by any Governmental Authority on the sale of Net Energy to Buyer under this Agreement regardless of whether such taxes are payable by Buyer or Seller under Requirements of Law.

6.4.5 Fines and Penalties.

6.4.5.1 Seller shall pay when due, and in no event later than thirty (30) days of assessment, all fines, penalties, or legal costs incurred by Seller or for which Seller is legally responsible for noncompliance by Seller, its agents, employees, contractors or subcontractors, with any provision of this Agreement, any agreement, commitment, obligation or liability incurred in connection with this Agreement or the Facility or any Requirements of Law, except where such fines, penalties or legal costs are being contested in good faith by Seller, its agents or contractors through appropriate proceedings with (i) adequate reserves set aside, or (ii) if requested by Buyer, the posting of adequate security, in the event of an adverse determination.

6.4.5.2 Subject to Section 6.4.4, if fines, penalties, or legal costs are assessed against Buyer by any Governmental Authority due to noncompliance by Seller with any Requirements of Law, or if the performance of Seller is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any Requirements of Law, Seller shall indemnify and hold harmless Buyer against any and all losses, liabilities, damages, and claims suffered or incurred by Buyer.

6.4.5.3 Seller shall reimburse Buyer for all fees, damages, or penalties imposed by any Governmental Authority, other person or to other utilities for violations to the extent caused by a Potential Event of Default or an Event of Default by Seller or a failure of performance by Seller under this Agreement.

6.5 Scheduling Procedures. [***Note to bidders: portions of this Section 6.5 may not be applicable to a non-facility dependent contract***]

6.5.1 Availability Notices and Updates.

6.5.1.1 By 5:00 A.M. PPT on the Business Day immediately preceding the next three (3) Days on which energy is to be delivered by Seller to Buyer, Seller shall provide Buyer with an hourly forecast of the Capacity of the Facility expected to be available to Buyer, up to the Contract Capacity, and for each hour of the next three (3) Days (as set forth in the form of **Exhibit L**, an "**Availability Notice**"); *provided*, *however*, that an Availability Notice provided on a Day before any non-Business Day shall include forecasts for each Day to and including the next Business Day. Delivery of an Availability Notice by Seller to Buyer with respect to any item of Major Equipment declared Available shall be deemed a declaration that all Ancillary Services capable of being provided from such Major Equipment are available for the Days for which such Availability Notice shall be effective. Seller shall promptly update Availability Notices any time information becomes available indicating a change in the forecast of generation of energy from the then current forecast; and in any event within 15 minutes of each time it becomes aware of a change (favorable or unfavorable) in the availability, or projected availability, of the Facility or electric transmission capacity, *provided* that such changes to the daily Availability Notices may be delivered by telephone within the fifteen (15) minute initial period and then later confirmed in writing within the hour. To the extent commercially reasonable, the parties shall cooperate to implement and use automatic forecast updates.

6.5.1.2 Availability Notices shall specify any known limitations on the availability of electric transmission capacity made known to Seller that may affect the ability of the Facility to generate and deliver Scheduled Energy to the Delivery Point. Seller will also provide Buyer with a monthly Availability Notice six Business Days before the commencement of each such month, and a weekly Availability Notice on each Friday for the next week. Availability Notices identifying reductions in availability will include a short description of the nature of the problem, steps taken or being taken to resolve it and Seller's estimate of the time by which a reduction in availability will be resolved. Availability Notices identifying projected restorations of Capacity availability will specify the time and extent that such restoration is projected to occur, and Seller will issue a further notice after restoration of availability is complete. Without limiting the foregoing, Seller will inform Buyer of any major limitations, restrictions, deratings or outages known to Seller affecting the ability to generate Facility Capacity for the following Day and will promptly update Seller's notice to the extent of any material changes in this information.

6.5.1.3 Availability Notices will be used by and relied upon by Buyer to establish and adjust electric transmission schedules. If Seller has provided notice to Buyer of a reduction in availability affecting transmission schedules, then prior to increasing Facility generation for delivery to Buyer as a result of restored availability, Seller will provide Buyer timely notice so as to enable Buyer sufficient time to reestablish its transmission schedules. The failure by Seller to provide revised Availability Notices is not a breach of this Agreement, but rather places Seller at risk for electric imbalance penalties or charges incurred by Buyer due to its lack of notice; *provided*, *however*, the failure to provide such notices more than **[?]** times a Contract Year shall constitute the failure to perform a material obligation hereunder that is not capable of being cured.

6.5.2 Dispatch Notice.

6.5.2.1 No later than 5:00 P.M. PPT on each Business Day, Buyer shall deliver to Seller a statement (which may be communicated by fax, e-mail or other electronic medium or a recorded telephone line) setting forth the estimated quantity of Net

Energy to be Scheduled during each hour of the immediately following Days at the Delivery Point. These estimates shall not be binding upon Buyer and Buyer may subsequently revise its estimates. The foregoing estimates by Buyer shall not be construed to permit Seller to limit the availability of the Facility such that Buyer is restricted from Dispatching Contract Capacity unless the Facility Capacity is physically unavailable due to Force Majeure, Planned Outage or Unplanned Outage, as the case may be. Buyer's written statement may request the delivery of energy to be Scheduled during any or all hours of any Day.

6.5.2.2 Each Dispatch Notice submitted by Buyer shall specify (i) the quantities of Net Energy or Ancillary Services being Scheduled from the Baseload Capacity component of the Contract Capacity, (ii) the quantities, if any, of Net Energy or Ancillary Services being Scheduled from the Peakload Capacity component of the Contract Capacity, and (iii) the quantities, if any, of Net Energy or Ancillary Services being Scheduled from the Facility in Simple Cycle mode. In order to be included on any Dispatch Notice, each quantity of Net Energy, and each equivalent quantity of Ancillary Services, being Scheduled by Buyer from the Baseload Capacity component of the Contract Capacity, or from the Peakload Capacity component of the Contract Capacity, or in Simple Cycle mode, must be shown as a dispatchable quantity on **Exhibit O**. Any amount not shown on **Exhibit O**, but which falls between listed numbers on **Exhibit O** and is explicitly within the range of allowed dispatch, shall be interpolated from the numbers immediately above and below that amount which are listed on **Exhibit O**, including applicable heat rates. An example of a hypothetical Dispatch Notice is attached hereto as **Exhibit R**.

6.5.2.3 Seller shall be obligated to accept a request for Net Energy that has been provided to Seller in accordance with the requirements of Sections 6.5.2.1 and 6.5.2.2 except to the extent (i) such request exceeds the Contract Capacity or the Scheduling Constraints or (ii) Seller declares that the Facility is not available as a result of a previously declared Planned Outage, a Forced Outage, or an event of Force Majeure. Seller shall promptly notify Buyer if Seller determines that it will not accept a Schedule submitted by Buyer for any of the foregoing reasons.

6.5.2.4 Buyer shall pay or reimburse Seller for all Scheduling Fees charged by any third parties, if any, associated with the Scheduling of Net Energy or Ancillary Services generated by the Facility for delivery to Buyer hereunder or, if applicable, any fees charged by an independent third party for providing Ancillary Services required to deliver Net Energy or Ancillary Services generated by the Facility to Buyer.

6.5.2.5 From time to time during the Term, Buyer may designate a third party to Schedule quantities of Net Energy on behalf of Buyer in accordance with any Requirements of Law. Buyer may also wish to change the designated entity acting in such capacity from time to time. Accordingly, upon request of Buyer, Seller shall make such arrangements in accordance with the Requirements of Law at Buyer's cost as may be reasonably necessary to facilitate the re-designation of the Person who may Schedule quantities of Net Energy on Buyer's behalf.

6.5.2.6 As shown in the Scheduling Constraints set forth for the Facility in **Exhibit P**, the ramp rates applicable to the various items of Major Equipment comprising the Facility are faster for the Facility operating in Simple Cycle mode than in combined cycle mode. To the extent that Buyer elects to Schedule the delivery of Net Energy, and any equivalent quantity of Ancillary Services, from the Facility in Simple Cycle mode the Scheduling Constraints applicable to Simple Cycle mode shall be applicable to such Scheduling by Buyer. For any Scheduling by Buyer of Net Energy or Ancillary Services from the Baseload Capacity component or the Peakload Capacity component of the Contract Capacity, the Scheduling Constraints applicable to combined cycle mode shall be applicable to such Scheduling by Buyer.

6.5.2.7 Buyer may Dispatch energy and Ancillary Services on a real time basis, subject to the Operating Procedures. Seller shall be obligated to accept a request for a change to the applicable schedule for energy and Ancillary Services.

6.6 Outages.

6.6.1 Planned Outages. No Planned Outage may be scheduled to occur during any portion of the time period commencing on May 15 and concluding on September 15.

6.6.2 Maintenance Outages. If Seller reasonably determines that it is necessary to schedule a Maintenance Outage, Seller shall notify Buyer of the proposed Maintenance Outage at least five (5) days before the outage begins (or such shorter period to which Buyer may reasonably consent in light of then existing conditions). Upon such notice, the Parties shall plan the Maintenance Outage to mutually accommodate the reasonable requirements of Seller and the service obligations of Buyer; *provided, however*, that, unless Buyer otherwise consents, such consent not to be unreasonably withheld, no Maintenance Outage may be scheduled between the hour ending 0700 through the hour ending 2200, Monday through Saturday, during the time period commencing on May 15 and concluding on September 15. Notice of a proposed Maintenance Outage shall include the expected start date and time of the outage, the amount of Capacity of the Facility that will not be available, and the expected completion date and time of the outage. Seller shall give Buyer notice of the Maintenance Outage as soon as Seller determines that the Maintenance Outage is necessary. Buyer shall promptly respond to such notice and may request reasonable modifications in the schedule for the outage. Seller shall use all reasonable efforts to comply with any request to modify the schedule for a Maintenance Outage. Seller shall notify Buyer of any subsequent changes in Capacity available to Buyer or any changes in the Maintenance Outage completion date and time. As soon as practicable, any notifications given orally shall be confirmed in writing. Seller shall take all reasonable measures and exercise its best efforts in accordance with Prudent Electrical Practices to minimize the frequency and duration of Maintenance Outages.

6.6.3 Forced Outages. Seller shall promptly provide to Buyer an oral report of any Forced Outage of the Facility. This report shall include the amount of the Capacity of the Facility that will not be available because of the Forced Outage and the expected return date of such Capacity. Seller shall promptly update the report as necessary to advise Buyer of changed circumstances. As soon as practicable, if the Forced Outage resulted in more than five percent (5%) of the Facility Capacity being unavailable, the oral report shall be confirmed in writing. Seller shall take all reasonable measures and exercise its best efforts in accordance with Prudent Electrical Practices to avoid Forced Outages and to minimize their duration.

6.6.4 Notice of Deratings and Outages. Without limiting the foregoing, Seller will inform Buyer of any major limitations, restrictions, deratings or outages known to Seller affecting the Facility for the following day and will promptly update Seller's notice to the extent of any material changes in this information, with "major" defined as affecting more than five percent (5%) of the Facility Capacity.

6.7 Schedule Coordination. If, as a result of this Agreement, Buyer is deemed by an RTO to be financially responsible for Seller's performance under the Interconnection Agreement, due to Seller's lack of a "scheduling coordinator" or other RTO recognized standing or otherwise, then (a) Seller shall use commercially reasonable and diligent efforts to acquire such RTO recognized standing such that Buyer is no longer responsible for Seller's performance under the Interconnection Agreement, and (b) Seller shall defend, indemnify and hold Buyer harmless against any liability arising due to Seller's performance or failure to perform under the Interconnection Agreement or Electric System Authority requirement.

6.8 Electronic Communications.

6.8.1 Telemetering. Seller shall provide telemetering equipment and facilities capable of transmitting the following information concerning the Facility pursuant to the Interconnection Agreement and to Buyer on a real-time basis and will operate such equipment when requested by Buyer to indicate:

6.8.1.1 instantaneous MW output at the Delivery Point;

6.8.1.2 Net Energy; and

6.8.1.3 Facility Capacity.

Seller shall also transmit to Buyer any other data from the Facility that Seller receives on a real time basis. Seller shall provide such real time data to Buyer on the same basis as the basis on which Seller receives the data (e.g., if Seller receives the data in four second intervals, Buyer shall also receive the data in four second intervals). Buyer shall have the right from time to time to require Seller to provide additional telemetering equipment and facilities to the extent necessary and reasonable.

6.8.2 Dedicated Communication Circuit. Seller shall install a dedicated direct communication circuit (which may be by common carrier telephone) between Buyer and the control center in the Facility's control room or such other communication equipment as the Parties may agree.

6.9 Reports and Records.

6.9.1 Monthly Reports. Within thirty (30) days after the end of each calendar month during the Term (each, a "**Reporting Month**"), Seller shall provide to Buyer a report in electronic format, which report shall include (a) summaries of the Facility's output data for the Reporting Month in intervals not to exceed one hour (or such shorter period as is reasonably possible with commercially available technology), including information from the Facility's Computer Monitoring System; (b) summaries of any other significant events related to the construction or operation of the Facility for the Reporting Month; and (c) any supporting information that Buyer may from time to time reasonably request (including historical data for the Facility).

6.9.2 Electronic Fault Log. Seller shall maintain an electronic fault log of operations of the Facility during each hour of the Term beginning as of the Commercial Operation Date. Seller shall provide Buyer with a copy of the electronic fault log within thirty (30) days after the end of the calendar month to which the fault log applies.

6.9.3 Other Information to Be Provided to Buyer. Seller shall provide to Buyer the following information concerning the Facility:

6.9.3.1 Upon the request of Buyer, the manufacturers' guidelines and recommendations for maintenance of the Facility equipment;

6.9.3.2 A detailed report summarizing the results of maintenance performed during each Planned Outage and any Forced Outage, and upon request of Buyer any of the technical data obtained in connection with such maintenance; and

6.9.3.3 A detailed report describing the facts, circumstances and events that caused and arose out of, or related to, any Forced Outage, failed Start-Up or other item of Major Equipment being taken off-line or tripping for any reason other than in connection with a Planned Outage.

6.9.4 Information to Any Governmental Authority. Seller shall, promptly upon written request from Buyer, provide Buyer with all data which is collected by Seller related to the Facility reasonably required for reports to and information requests from any Governmental Authority. Along with said information, Seller shall provide to Buyer copies of all submittals to any Governmental Authority directed by Buyer and related to the operation of the Facility with a certificate that the contents of the submittals are true and accurate to the best of Seller's knowledge. Seller shall use best efforts to provide this information to Buyer soon enough so that Buyer has time to review such information and meet any submission deadlines imposed by the requesting organization or entity. After the sending or filing any statement, application, and report or any document with any Governmental Authority relating to operation and maintenance of the Facility, Seller shall promptly provide to Buyer with a copy of the same.

6.9.5 Information to Any Intervenor. Seller shall, promptly upon written request from Buyer, provide Buyer with data reasonably required for information requests from any state or federal agency intervenor or any other party achieving intervenor status in any Buyer rate proceeding or other proceeding before any Governmental Authority. Seller shall use best efforts to provide this information to Buyer soon enough so that Buyer has time to review such information and meet any submission deadlines imposed by the requesting organization or entity.

6.9.6 Environmental Information. Seller shall, promptly upon written request from Buyer, provide Buyer with all data reasonably requested by Buyer relating to environmental information under the Required Facility Documents. Seller shall disclose to Buyer, as soon as it is known to Seller, any material violation of any environmental laws or regulations arising out of the construction or operation of the Facility, and the extent thereof, or the presence of Environmental Contamination at the Facility or on the Premises, alleged to exist by any Governmental Authority having jurisdiction over the Premises, or the existence of any past or present enforcement, legal, or regulatory action or proceeding relating to any actual or alleged violation or presence of Environmental Contamination.

6.9.7 Information Relating to Facility Performance. Seller shall provide Buyer monthly operational reports in a form and substance acceptable to Buyer and Seller shall, promptly upon written request from Buyer, provide Buyer with all operational data requested by Buyer with respect to the performance of the Facility and delivery of energy therefrom.

6.9.8 Audited Financial Statements. Seller shall provide Buyer within ninety (90) days after the end of each calendar year, its audited financial statements together with the audited financial statements of any guarantor providing Credit Support, in each case prepared in accordance with generally accepted accounting principles by an accounting firm of nationally recognized standing in the electric power industry reasonably acceptable to Buyer.

6.9.9 Notice of Default. Seller shall promptly notify Buyer of receipt of written notice or actual knowledge of the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement.

6.9.10 Notice of Litigation. Following its receipt of written notice or actual knowledge of the commencement of any action, suit, and proceeding before any court or Governmental Authority which would, if adversely determined, adversely affect Seller, the Premises or the Facility, Seller shall promptly give notice to Buyer of the same.

6.9.11 Additional Information. Seller shall provide to Buyer such other information respecting the condition or operations of Seller and the Facility as Buyer may, from time to time, reasonably request.

6.10 Access Rights. Upon reasonable prior notice and subject to the safety rules and regulations of Seller, Seller shall provide Buyer and its authorized agents, employees and inspectors with reasonable access to the Facility: (a) for the purpose of reading or testing metering equipment, (b) as necessary to witness any required Capacity tests necessary to determine the amount of Capacity associated with the Facility, (c) in connection with the operation and maintenance of the Electrical Interconnection Facilities for the Facility, (d) to provide tours of the Facility to customers and other guests of Buyer (not more than twelve (12) times per year), (e) for purposes of implementing Section 9.5, and (f) for other reasonable purposes at the reasonable request of Buyer.

6.11 EWG. Seller shall provide Buyer with copies of Seller's applications to FERC for EWG status and for authority to sell energy under this Agreement within ten (10) days of filing such applications. During the Term, Seller shall either (i) maintain its EWG status and its authority to sell power under this Agreement or (ii) otherwise cause Seller to be exempt from federal and state regulations as an electric utility.

6.12 Facility Images. Buyer shall be free to use any and all images from or of the Facility for promotional purposes. Upon Buyer's request and at Buyer's expense, Seller shall install equipment as Buyer may request, including without limitation video and or web-based imaging equipment. Buyer shall use its discretion with respect to how images from or of the Facility are presented by Buyer, including without limitation associating images of the Facility with Buyer's corporate logo but not the corporate logo of Seller.

6.13 Financial and Accounting Information. If Buyer or one of its Affiliates determines that, under the Financial Accounting Standards Board's revised Interpretation No. 46, Consolidation of Variable Interest Entities ("**FIN 46**"), it may hold a variable interest in Seller, but it lacks the information necessary to make a definitive conclusion, Seller hereby agrees to provide sufficient financial and ownership information so that Buyer or its Affiliate may confirm whether a variable interest does exist under FIN 46. If Buyer or one of its affiliates determines that, under FIN 46, it holds a variable interest in Seller, Seller hereby agrees to provide sufficient financial and other information to Buyer or its Affiliate so that Buyer may properly consolidate the entity in which it holds the variable interest or present the disclosures required by FIN 46.

SECTION 7

SECURITY AND CREDIT SUPPORT

7.1 Credit Support. At any time during the Term, Seller may have to post Credit Support Security in the amounts outlined on the Credit Matrix based upon its' Credit Rating or that of the entity providing credit assurances as Credit Support Security on behalf of Seller, and the size of the project. If the required Credit Support is greater than zero dollars ($0.00), upon the request of Buyer, Seller shall provide the Credit Support in the form of: (x) a guaranty, in form and substance acceptable to Buyer in its sole discretion from a Person acceptable to Buyer in its sole discretion, (y) a Let er of Credit, or (z) a Cash Escrow. Buyer shall be required to post Credit Support Security according to the schedule outlined in Attachment 21 to the All Source RFP; however at the time the milestone set forth in Section 2.2.3 has been met, Buyer shall be required to post Credit Support Security in the amount of 100% of the required Credit Support.

7.2 Subordinated Security Interests.

7.2.1 Security Interests. Concurrently with the execution of this Agreement and simultaneously with the acquisition by Se ler after the Effective Date of any real property in connection with the Facility (including land and water or rights thereto), Seller shall execute, file and record such agreements, documents, instruments, deeds of trust and other writings as Buyer may request, all in form and substance satisfactory to Buyer, to give Buyer a perfected security interest in and lien on the Fac lity, the Premises and all other assets necessary or in Buyer's opinion desirable for the development, construction, ownership, operation or maintenance of the Facility as security for Seller's performance and any amounts owed by Seller to Buyer pursuant to this Agreement (collectively the "**Security Interests**"). The Security Interests shall be subordinate in right of payment, priority and remedies only to the interests of the financiers for the Facility contemplated by Section 2.2.3 and approved by Buyer.

7.2.2 Pledge of Ownership Interests. *[Note to bidders: This section is applicable only if Seller is a special purpose entity.]* Concurrently with the execution of this

Agreement, Seller's equity holders shall execute and file such agreements, documents, instruments, and other writings as Buyer may request, all in form and substance satisfactory to Buyer, to give Buyer a perfected security interest in and lien on all ownership interests in Seller as security for Seller's performance and any amounts owed by Seller to Buyer pursuant to this Agreement (the "**Pledge Interest**"). The Pledge Interest shall be subordinate in right of payment, priority and remedies only to the interests of the financiers for the Facility contemplated by Section 2.2.3 and approved by Buyer.

7.2.3 Maintenance of Security Interests. Seller shall execute and file and record (or cause to be executed and filed and recorded) such Uniform Commercial Code financing statements and deeds of trust and shall take such further action and execute such further instruments and other writings as shall be required by Buyer to confirm and continue the validity, priority, and perfection of the Security Interests [and the Pledge Interest]. The granting of the Security Interests [and the Pledge Interest] shall not be to the exclusion of, nor be construed to limit the amount of any further claims, causes of action or other rights accruing to Buyer by reason of any breach or default by Seller under this Agreement or the termination of this Agreement prior to the expiration of the Term.

7.2.4 Transfer of Required Facility Documents. The Security Interests shall provide that if Buyer acts to obtain title to the Facility pursuant to the interests provided by Seller pursuant to Section 7.2.1, Seller shall take all steps necessary to transfer all Required Facility Documents necessary to operate the Facility to Buyer, and shall diligently prosecute and cooperate in such transfers.

7.3 Quarterly Financial Statements. If requested by Buyer, Seller shall within thirty (30) days provide Buyer with copies of its most recent quarterly financial statements, together with the audited financial statements of any guarantor providing Credit Support, in each case prepared in accordance with generally accepted accounting principles.

7.4 Security is Not a Limit on Seller's Liability. The Credit Support and Security Interests contemplated by this Section 7: (a) constitutes security for, but is not a limitation of, Seller's obligations under this Agreement, and (b) shall not be Buyer's exclusive remedy for Seller's failure to perform in accordance with this Agreement. To the extent that Buyer draws on the Credit Support, Seller shall within five (5) Busines Days reinstate the security to the full amount required by this Section 7.

7.5 Escrow Account. With respect to any Cash Escrow established pursuant to this Section 7 as Credit Support, Seller hereby grants Buyer a security interest in the escrow account and all moneys and other amounts in the account to secure payment and performance of Seller's obligations under this Agreement. Buyer shall have, and Seller agrees to take all further action required or reasonably requested by Buyer to ensure th t Buyer has, all rights of a secured party under Article 9 of the Uniform Commercial Code and applicable law with respect to the escrow account nd all moneys and other amounts in the escrow account. The escrow agreement shall be in form and substance acceptable to Buyer in its discretion and shall contain the following language: "Escrow Agent acknowledges that Seller has granted Buyer a security interest in the amounts held by Escrow Agent in the [***describe escrow accounts and all moneys and other amounts in the account***] (collectively, the "**Collateral**"). Escrow Agent acknowledges that it

(a) has received and holds possession of the Collateral for the benefit of Buyer and not as the agent of or on behalf of Seller and (b) shall continue to hold possession of the Collateral for Buyer's benefit until Escrow Agent receives notice in an authenticated record from Buyer that Buyer's security interest in the Collateral has been terminated. Escrow Agent acknowledges that it has no rights in and to the Collateral other than its right to receive payment of its fees and expenses pursuant to the Escrow Agreement."

SECTION 8

METERING

8.1 Net Energy. Meter equipment shall be installed, owned, operated, maintained and tested in accordance with the terms of the Interconnection Agreement and shall automatically account for line losses between such meter equipment and the Delivery Point (collectively, the "**Electric Metering Equipment**"). The Electric Metering Equipment shall be capable of metering Net Energy delivered at the Delivery Point on a continuous real time basis.

8.1.1 Seller Electric Metering. Seller shall be responsible for the maintenance, testing and calibration of the Electric Metering Equipment and the maintenance and testing of the electrical facilities and Protective Apparatus, including any transmission equipment and related facilities, necessary to interconnect the Facility at the Delivery Point. Such installation shall be completed, and the delivery of such data shall be commenced, as promptly as possible but in no event later than one month prior to the commencement of Net Energy deliveries. Seller shall bear all costs and expenses of installing, maintaining and testing all Electric Metering Equipment.

8.1.2 Check Meters. Buyer may at its option and expense install and operate one or more check meters to check Seller's meters. Such check meters shall be for check purposes and shall not be used in the measurement of Net Energy or Ancillary Services for the purposes of this Agreement. The check meters shall be subject at all reasonable times to inspection and examination by Seller or its designee. The installation and operation thereof shall, however, be done entirely by Buyer at no cost or expense to Seller. Seller shall grant to Buyer, at no cost or expense, the right to install such check meters at the Delivery Point and the right to access such check meters at reasonable times as requested by Buyer if such check meters are located on the Premises.

8.1.3 Change in Measurement Method. If, at any time during the Term a new method or technique is developed with respect to electricity measurement, or the determination of the factors used in electricity measurement, such new method or technique may be substituted for the method set forth in this Section 8.1 when in the opinion of the Parties, employing such new method or technique is advisable, and they so agree in writing.

8.1.4 Industry Standards. All Electric Metering Equipment, whether owned by Seller or by a third party, shall be operated, maintained and tested by or on behalf of Seller in accordance with Prudent Electrical Practices.

8.1.5 Access. Each Party shall have the right to receive reasonable advance notice with respect to, and to be present at the time of, any installing, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting of Electric Metering Equipment. The records from such Electric Metering Equipment shall be the property of Seller, but upon reasonable advance notice, Seller shall make available to Buyer all data, records and charts relating to the Electric Metering Equipment, together with calculations therefrom, for inspection and verification.

8.1.6 Installations. Any installations of Electric Metering Equipment required pursuant to this Agreement shall be scheduled by Seller; provided, however, that no installation which shall or could affect deliveries of Net Energy shall be made without the prior written consent of Buyer, which shall not be unreasonably withheld. Any installations of check meters by Buyer shall be scheduled by Buyer; provided, however that the installation shall not unreasonably interfere with the operation and maintenance of the Facility by Seller.

8.1.7 Estimates. During the period after the Effective Date and prior to the installation and commencement of operation of the meters contemplated by this Section 8.1.8, the Net Energy generated and delivered shall be estimated in good faith by Seller and the Parties shall prepare and submit invoices on the basis of such estimates. Any such invoice shall be adjusted retroactively based on the performance of the Facility during the three month period immediately following the installation of such meters.

8.1.8 Inspection. Seller, at its sole cost and expense, shall inspect and calibrate, or cause to be inspected and calibrated, all Electric Metering Equipment periodically, but not less frequently than annually. When any test, in the case of Electric Metering Equipment, shall show a measurement error of more than one-quarter percent (1/4%), correction shall be made for the period during which the measurement instruments were in error, first, by using the registration of Buyer's check meter, if installed and registering accurately; if no check meter is installed and registering accurately, or if the period cannot be ascertained, correction shall be made for one-half (1/2) of the period elapsed since the last date of test; and the measuring instrument shall be adjusted immediately to measure accurately.

8.2 Records. The Parties shall, for five (5) years or such longer period as may be required by the applicable Governmental Authority, each keep and maintain accurate and detailed records relating to the Facility's hourly deliveries of Net Energy. Such records shall be made available for inspection by either Party or any Governmental Authority having jurisdiction with respect thereto during normal business hours upon reasonable notice. If either Party (the "**Notifying Party**") shall propose to discard any records theretofore required to be retained by this Section 8.2, it shall give notice to the other Party thereof and the other Party may within thirty (30) days elect to take possession of such records by notice to the Notifying Party, and in such case the Notifying Party shall promptly, and in any event, no later than five (5) days following receipt of such notice, deliver such records to the other Party at its expense. If the Party receiving a Notice pursuant to this Section 8.2 shall not respond within such thirty (30) days, the Notifying Party may discard such records without any further obligation hereunder. Upon written request by Buyer, Seller promptly shall request that the Transmission Provider provide in writing any and all meter or other data associated with the Facility and Net Energy directly to Buyer. Notwithstanding any other provision of this Agreement, Buyer shall have the right to provide such meter data to any RTO or generation tracking service.

8.3 Adjustment to Loss Factors. If Buyer or Seller has a reasonable basis for concluding that the Electric Metering Equipment is not accurately measuring losses between the Electric Metering Equipment and the Delivery Point, it may propose an adjustment to the Electric Metering Equipment by notice to the other Party. Such an adjustment shall be prospective only. The notice will include information explaining in reasonable detail why the loss factor appears to be incorrect. The other Party shall have thirty (30) days in which to approve or disapprove of the proposed adjustment, which approval may not be unreasonably withheld, conditioned or delayed. A proposed loss factor adjustment that is not disapproved by notice to Seller given within the thirty (30) day period shall be deemed approved. The Parties shall cooperate in causing PacifiCorp Transmission to make an appropriate adjustment to the Electric Metering Equipment pursuant to the Interconnection Agreement.

SECTION 9

BILLINGS, COMPUTATIONS AND PAYMENTS

9.1 Monthly Invoices. On or before the tenth (10th) day following the end of each month, Seller shall deliver to Buyer a proper invoice showing Seller's computation of the Energy Payment, MAAF and the Capacity Payment for such month. If such invoice is delivered by Seller to Buyer, Buyer shall send to Seller payment for Seller's deliveries in respect thereof on or before the thirtieth (30th) day following the end of each month.

9.2 Offsets. Buyer may offset any payment due under this Agreement against amounts owing from Seller to Buyer pursuant to this Agreement, any other agreement between the Parties or otherwise. Buyer's exercise of recoupment and set off rights shall not limit the other remedies available to Buyer hereunder, under such other agreements, or otherwise.

9.3 Interest on Late Payments. Any amounts that are not paid when due under this Agreement shall bear interest at the Prime Rate plus two hundred (200) basis points from the date due until paid; provided, however, that this interest rate shall at no time exceed the maximum rate allowed by applicable law.

9.4 Disputed Amounts. If either Party, in good faith, disputes any amount due pursuant to an invoice rendered or written demand made under this Agreement, such Party shall notify the other Party of the specific basis for the dispute and, if the invoice shows an amount due, shall pay that portion of the statement that is undisputed, on or before the due date. Any such notice shall be provided within two (2) years of the date of the invoice in which the error first occurred. If any amount disputed by such Party is determined to be due the other Party, or if the Parties resolve the payment dispute, the amount due shall be paid within five (5) days of such determination or resolution, along with interest accrued at the rate determined under Section 9.3 from the date due until the date paid.

9.5 Audit Rights. Buyer, through its authorized representatives, shall have the right, at its sole expense and during normal business hours, to examine and copy the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made hereunder or to verify Seller's performance of its obligations hereunder. Upon request, Seller shall provide to Buyer statements evidencing the quantities of Net Energy delivered at the Delivery Point. If any statement is found to be inaccurate, a corrected statement shall be issued and any amount due thereunder will be promptly paid and shall bear interest calculated at the rate determined under Section 9.3 from the date of the overpayment or underpayment to the date of receipt of the reconciling payment. Notwithstanding the above, no adjustment shall be made with respect to any statement or payment hereunder unless Buyer questions the accuracy of such payment or statement within two (2) years after the date of such statement or payment.

SECTION 10

DEFAULTS AND REMEDIES

10.1 Defaults. The following events are defaults (each, an "**Event of Default**") under this Agreement:

10.1.1 Events of Default by Either Party.

10.1.1.1 A Party's failure to make a payment when due under this Agreement if the failure is not cured within ten (10) days after the non-defaulting Party gives the defaulting Party a notice of the default, except as provided in Section 9.4.

10.1.1.2 A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

10.1.1.3 A Party's breach of a representation or warranty made by that Party in this Agreement if the breach is not cured within thirty (30) days after the non-defaulting Party gives the defaulting Party a notice of the default.

10.1.1.4 A Party otherwise fails to perform any material obligation imposed upon that Party by this Agreement if the failure is not cured within thirty (30) days after the non-defaulting Party gives the defaulting Party notice of the default; provided, however, that, upon written notice from the defaulting Party, this thirty (30) day period shall be extended by an additional sixty (60) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional sixty (60) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

10.1.2 Events of Default by Seller.

10.1.2.1 Seller's failure to post or increase the Carry-Over Letter of Credit within ten (10) Business Days after the end of each month as may be required under Section 5.1.4.

10.1.2.2 Seller's failure to cause the Facility to achieve (a) an average of the applicable CAF_ms of at least [?%] in any three (3) consecutive quarters in a

Contract Year or (b) achieve an average of the applicable CAF_ms of at least **[?%]** in three (3) out of any five (5) consecutive Contract Years. [bidder to edit and provide parameters]

10.1.2.3 Seller's failure to post and maintain Credit Support as required by Section 7 if the failure is not cured within five (5) days after Buyer gives Seller a notice of the default.

10.1.2.4 Seller's failure to achieve a milestone by the date set forth for the achievement of that milestone in Section 2.2 (other than the failure to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date) if the failure is not cured within thirty (30) days after Buyer gives Seller a notice of the default.

10.1.2.5 Seller's failure to cause the Facility to achieve the Commercial Operation Date on or before [___] days following the Guaranteed Commercial Operation Date. ***[note to bidders: insert number of days; this will be a material component of the evaluation of your bid; the nature of the resource will be considered. The lowest feasible numeral is encouraged.]***

10.1.2.6 Seller's failure to cure any default under any Required Facility Documents (including the Interconnection Agreement) within the time allowed for a cure under such agreement or instrument.

10.1.2.7 Seller's sale of energy from the Facility to a Party other than Buyer in breach of this Agreement if Seller does not permanently cease such sale and compensate Buyer for the damages arising from the breach within ten (10) days after Buyer gives Seller a notice of default.

10.1.2.8 Seller's Abandonment of the Facility, or the Facility is unavailable to provide energy for ninety (90) consecutive days or one hundred twenty (120) non-consecutive days in any three hundred sixty-five (365) day period commencing on the Commercial Operation Date and prior to end of the Term.

10.2 Termination and Remedies.

10.2.1 Upon the occurrence of, and during the continuation of, an Event of Default, the non-defaulting Party shall be entitled to all remedies available at law or in equity, and may terminate this Agreement by notice to the other Party designating the date of termination and delivered to the defaulting Party no less than ten (10) days before such termination date; provided, however, that as a precondition to Seller's exercise of this termination right, Seller must provide copies of such notice to the notice addresses set forth in Section 22. Such copies shall be sent by registered overnight delivery service or by certified or registered mail, return receipt requested and shall state prominently therein in typefont no smaller than fourteen (14) point all-capital letters that "THIS IS A TERMINATION NOTICE UNDER A PPA. YOU MUST CURE A DEFAULT, OR THE PPA WILL BE TERMINATED," and shall state therein any amount purported to be owed and wiring instructions. Seller will not have any right to terminate this Agreement if the default that gave rise to the termination right is cured within the fifteen (15) Business Days of PacifiCorp's receipt of such notice.. Further, during the continuation of an Event of Default by Seller, and until it has recovered all damages incurred on account of such Event of Default by Seller, without exercising its termination right, Buyer may offset its damages against any payment due Seller.

10.2.2 In the event of a termination of this Agreement:

10.2.2.1 The Parties' respective obligations under this Agreement shall terminate (other than those obligations which expressly are to be performed after termination).

10.2.2.2 Each Party shall pay to the other all amounts due the other under this Agreement for all periods prior to termination subject to offset by the non-defaulting Party against damages incurred by such Party.

10.2.2.3 The amounts due pursuant to Section 10.2.2.2 shall be paid within thirty (30) days of the billing date for such charges plus interest thereon at the Prime Rate from the date of termination until the date paid. The foregoing does not extend the due date of, or provide an interest holiday for any payments otherwise due hereunder.

10.2.2.4 Without limiting the generality of the foregoing, the provisions of Sections 6.4.4, 6.9.4, 6.9.5, 8.2, 9.3, 9.4, 9.5, 10.7, 10.9, 11 and 14 shall survive the termination of this Agreement.

10.3 <u>Specific Performance</u>. Buyer shall be entitled to seek and obtain a decree compelling specific performance or granting injunctive relief with respect to, and shall be entitled, without the necessity of filing any bond, to enjoin any actual or threatened breach of any material obligation of Seller under this Agreement. Seller agrees that in view of the nature of the bid procedure that caused Seller to be selected, and the importance of the Facility and Buyer's requirement for Capacity and energy, specific performance (including temporary and preliminary relief) and injunctive and other equitable relief, including access to all records of Seller, are proper in the event of any actual or threatened breach of any material obligation by Seller under this Agreement, and that any liability limits contained in this Agreement shall not operate to limit the exercise of Buyer's remedies in equity to cause Seller to perform its obligations under this Agreement. In any action for specific performance or injunctive relief or other equitable relief, all expenses incurred by the prevailing party in such proceeding, including reasonable counsel fees, shall be awarded to the prevailing party in such proceeding. Seller agrees that it will not assert as a defense to Buyer's action for specific performance of, or injunctive relief or other equitable relief relating to, Seller's obligations hereunder that the amounts payable or paid by Seller in respect of liquidated damages or actual damage constitute an adequate remedy for the breach of such obligation, and Seller hereby conclusively waives such defense.

10.4 <u>Failure to Meet Availability</u>. If an Event of Default by Seller described in Section 10.1.2.2 shall occur, Buyer shall have the right to enter the Facility and do all such things as Buyer may consider necessary or desirable to remedy such situation or to improve the availability of the Contract Capacity, including making any repairs to the Major Equipment or the Facility. Seller shall reimburse Buyer for and shall indemnify and hold harmless Buyer from and against all losses, costs, charges and expenses incurred by Buyer in connection with exercise of its rights under this Section 10.4 other than due to the gross negligence or willful misconduct of Buyer. In connection with the exercise of the rights under this Section 10.4, Buyer shall have the right to recoup and set off all such losses, costs, charges and expenses against amounts otherwise owed by Buyer under this Agreement.

10.5 License to Operate Facility. During the occurrence and continuance of an Event of Default by Seller, Seller hereby irrevocably grants to Buyer the right, license, and authority to enter the Premises, operate the Facility, and to perform Seller's obligations under this Agreement for the Term of this Agreement. Notwithstanding the license gr nted to Buyer in this Section 10.5, so long as no Event of Default by Seller which would entitle Buyer to terminate this Agreement has occurred and is continuing, Buyer agrees that Seller may operate the Facility and provide the energy and Capacity in accordance with its obligations under this Agreement. Upon the occurrence of an Event of Default and the expiration of all applicable opportunities to cure, Buyer may, but shall not be obligated to, exercise its rights as licensee under this Section 10.5 in lieu of termination. Buyer's right to operate the Facility pursuant to the license granted in this Section 10.5 shall be effective for a period not to exceed 365 days from the date Buyer first exercises its license rights. During any period in which Buyer is operating the Facility pursuant to the license granted in this Section 10.5, Seller shall, upon request from Buyer, reimburse Buyer for all reasonable costs and expenses incurred by Buyer to operate and maintain the Facility. In connection with the exercise of the rights under this Section 10.5, Buyer shall have the right to recoup and set off all such losses, costs, charges and expenses against amounts otherwise owed by Buyer under this Agreement.

10.6 Termination of Duty to Buy. If this Agreement is terminated because of Seller's default, Seller may not require Buyer to purchase energy from the Facility before the date on which the Term would have ended had this Agreement remained in effect. Seller hereby waives its rights to require Buyer to do so.

10.7 Net Replacement Power Costs. If this Agreement is terminated because of Seller's default, Seller shall pay Buyer the positive difference, if any, obtained by subtracting (a) the result of (1) the energy, stated in MWh, that Seller was obligated to provide to Buyer during the remainder of the Term, multiplied by (2) the price per MWh (i) specified in **Exhibit F** for the remaining Contract Years subtracted from (ii) the market price of such energy as determined in good faith by Buyer, from (b) the Replacement Price for any energy that Seller was obligated to provide during the remainder of the Term. Amounts owed by Seller pursuant to this Section 10.7 shall be due within five (5) Business Days after Buyer gives Seller notice of the amount due.

10.8 Credit Support Security. Buyer may apply the Credit Support Security at any time to reduce amounts due from Seller to Buyer under this Agreement which are not paid when due.

10.9 Cumulative Remedies. The rights and remedies provided to Buyer under this Agreement are cumulative and not exclusive of any rights or remedies which Buyer would otherwise have.

SECTION 11

INDEMNIFICATION AND LIABILITY

11.1 Indemnities.

11.1.1 Indemnity by Seller. Seller hereby releases, indemnifies and holds harmless Buyer, its directors, officers, agents, and representatives against and from any and all losses, claims, actions or suits, including costs and attorney's fees, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Delivery Point, (b) any facilities on Seller's side of the Delivery Point, (c) Seller's operation or maintenance of the Facility, or (d) arising from Seller's performance under this Agreement, including any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to Buyer, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Buyer, its directors, officers, employees, agents or representatives.

11.1.2 Indemnity by Buyer. Buyer hereby releases, indemnifies and holds harmless Seller, its directors, officers, agents, and representatives against and from any and all losses, claims, actions or suits, including costs and attorney's fees, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Delivery Point, including any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents or representatives.

11.2 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of Buyer as an independent public utility corporation or Seller as an independent individual or entity.

11.3 Consequential Damages. Neither Party shall be liable to the other Party for special, punitive, indirect, exemplary or consequential damages, whether such damages are allowed or provided by contract, tort (including negligence), strict liability, statute or otherwise.

SECTION 12

INSURANCE

12.1 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "A" by the A.M. Best Company the insurance coverage specified on **Exhibit J** during the periods specified on **Exhibit J.**

12.2 Certificates and Certified Copies of Policies. Seller shall provide Buyer with a certified "true and correct" copy of the insurance policies, provisions and endorsements contemplated by **Exhibit J** within ten (10) days after the date by which such policies are required to be obtained (as set forth in **Exhibit J**). If any coverage is written on a "claims-made" basis, the certification accompanying the policy shall conspicuously state that the policy is "claims made."

SECTION 13

FORCE MAJEURE

13.1 Definition of Force Majeure. As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means an event (a) is not reasonably anticipated as of the date of this Agreement, (b) is not within the reasonable control of the Party affected by the event, (c) is not the result of such Party's negligence or failure to act, and (d) could not be overcome by the affected Party's use of due diligence in the circumstances. Force Majeure includes events of the following types only to the extent that such an event, in consideration of the circumstances, satisfies the tests set forth in the preceding sentence: acts of God; fire; explosion; civil disturbance; sabotage; and action or restraint by court order or public or government authority (as long as the affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such court or government action). Notwithsta ding the foregoing, none of the following constitute Force Majeure: (i) Seller's ability to sell, or Buyer's ability to purchase energy at a more advantageous price than is provided under this Agreement; (ii) the cost or availability of Fuel; (iii) economic hardship including lack of money; (iv) the imposition upon Seller of costs or taxes allocated to Seller under Sections 5 or 6; (v) delay or failure by Seller to obtain any Required Facility Document, other than Permits which Seller is diligently a d timely taking all reasonable steps to obtain; (vi) strikes or labor disturbances occurring at the Faci ity, the Premises or any of Buyer's or Seller's facilities; (vii) changes in, or costs of compliance with, Environmental Laws enacted after the date of this Agreement; (viii) curtailment or suspension of transmission or directive from the Transmission Provider or Interconnection Provider to curtail or suspend deliveries; (ix) the failure of the Interconnection Provider or Transmission Provider, whether or not the Interconnection Provider or Transmission Provider is PacifiCorp acting in its regulated transmission function capacity, for any reason to transmit Contract Capacity or energy and (x) increased cost of electricity, steel, labor, or transportation constitute an event of Force Majeure.

13.2 Suspension of Performance. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an evento f Force Majeure, both Parties shall be excused from the performance affected by the event of Force Majeure, provided that:

13.2.1 the Party affected by the Force Majeure, shall, within two (2) weeks after the occurrence of the event of Force Majeure, give the other Party written notice describing the particulars of the event; and

13.2.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and

13.2.3 the affected Party shall use diligent efforts to remedy its inability to perform.

13.3 Force Majeure Does Not Affect Other Obligations. No obligations of either Party that arose before the Force Majeure causing the suspension of performance or that arise after the cessation of the Force Majeure shall be excused by the Force Majeure.

13.4 Right to Terminate. If a Force Majeure event prevents a Party from substantially performing its obligations under this Agreement for a period exceeding one hundred eighty (180) days, then Buyer may terminate this Agreement by giving ten (10) days' prior notice to Seller. Upon such termination, neither Party will have any liability to the other with respect to the period following the effective date of such termination; *provided, however*, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising under this Agreement before the effective date of such termination.

SECTION 14

CONFIDENTIALITY

14.1 Confidential Business Information. The Parties' proposals and negotiations prior to the date hereof concerning this Agreement, the terms of this Agreement, and the actual charges billed to Buyer under this Agreement, constitute the "Confidential Business Information" of both Parties. Seller and Buyer each agree to hold such Confidential Business Information wholly confidential.

14.2 Duty to Maintain Confidentiality. Confidential Business Information may only be used by the Parties for purposes related to the approval, administration or enforcement of this Agreement and for no other purpose. Each Party agrees not to disclose Confidential Business Information to any other person (other than its affiliates, counsel, consultants, lenders, prospective lenders, buyers, prospective buyers, contractors constructing or providing services to the Facility, employees, officers and directors who agree to be bound by the provisions of this Section), without the prior written consent of the other Party, provided that either Party may disclose Confidential Business Information, if such disclosure is required by law, required in order for Buyer to receive regulatory recovery of expenses related to the Agreement or pursuant to an order of a court or regulatory agency or in order to enforce this Agreement or to seek approval of this Agreement. In the event a Party is required by law or by a court or regulatory agency to disclose Confidential Business Information, such Party shall to the extent possible notify the other Party at least three (3) Business Days in advance of such disclosure.

14.3 Irreparable Injury; Remedies. Each Party agrees that violation of the terms of this Section 14 constitutes irreparable harm to the other, and that the harmed Party may seek any and all remedies available to it at law or in equity, including injunctive relief.

14.4 News Releases and Publicity. Before issuing any news release or promotional material regarding the Facility, Seller shall contact Buyer for language that credits Buyer as purchasing the Net Energy and shall use such language in such news releases and promotional material.

SECTION 15

DISPUTE RESOLUTION

15.1 Negotiations. The Parties shall attempt in good faith to resolve all disputes arising out of or related to or in connection with this Agreement promptly by negotiation, as follows. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels one level above the personnel who have previously been involved in the dispute shall meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days from the referral of the dispute to senior executives, or if no meeting of such senior executives has taken place within fifteen (15) days after such referral, either Party may initiate litigation as provided hereinafter if neither Party has requested that the dispute be mediated in accordance with Section 15.2 below. All negotiations pursuant to this clause are confidential.

15.2 Mediation. If the dispute is not resolved within thirty (30) days from the referral of the dispute to senior executives, or if no meeting of senior executives has taken place within fifteen (15) days after such referral, either Party may request that the matter be submitted to nonbinding mediation. If the other Party agrees, the mediation will be conducted in accordance with the Construction Industry Arbitration Rules and Mediation Procedures (Including Procedures for Large, Complex Construction Disputes) of the American Arbitration Association (the "**AAA**"), as amended and effective on July 1, 2003 (the "**Mediation Procedures**"), notwithstanding any Dollar amounts or Dollar limitations contained therein.

15.2.1 The Party requesting the mediation, may commence the mediation process with AAA by notifying AAA and the other Party in writing ("**Mediation Notice**") of such Party's desire that the dispute be resolved through mediation, including therewith a copy of the Dispute Notice and the response thereto, if any, and a copy of the other Party's written agreement to such mediation.

15.2.2 The mediation shall be conducted through, by and at the office of AAA located in Salt Lake City, Utah.

15.2.3 The mediation shall be conducted by a single mediator. The Parties may select any mutually acceptable member from the panel of retired judges at AAA as a mediator. If the parties cannot agree on a mediator within five (5) days after the date of the Mediation Notice, then the AAA's Arbitration Administrator shall send a list and resumes of three (3) available mediators to the parties, each of whom shall strike one name, and the remaining person shall be appointed as the mediator. If more than one name remains, either because one or both parties have failed to respond to the AAA's Arbitration Administrator within five (5) days of receiving the list or because one or both parties have failed to strike a name from the list or because both parties strike the same name, the AAA's Arbitration Administrator will choose the mediator from the remaining names. If the designated mediator shall die, become incapable or, unwilling to, or unable to serve or proceed with the mediation, a substitute mediator shall be appointed in accordance with the selection procedure described above in this Section 15.2.3, and such substitute mediator shall have all such powers as if he or she has been originally appointed herein.

15.2.4 The mediation shall consist of one or more informal, nonbinding meetings between the Parties and the mediator, jointly and in separate caucuses, out of which the mediator will seek to guide the Parties to a resolution of the dispute. The mediation process shall continue until the resolution of the dispute, or the termination of the mediation process pursuant to Section 15.2.7.

15.2.5 The mediator's fees and expenses, shall be borne equally by the Parties. Each Party shall bear its own expenses incurred in connection with such mediation; provided, however, that if any dispute hereunder is not fully resolved as a result of such mediation, the prevailing party shall be awarded its reasonable attorney fees in any subsequent dispute resolution proceedings.

15.2.6 All verbal and written communications between the parties and issued or prepared in connection with this Section 15.2 shall be deemed prepared and communicated in furtherance, and in the context, of dispute settlement, and shall be exempt from discovery and production, and shall not be admissible in evidence (whether as admission or otherwise) in any other proceedings for the resolution of the dispute.

15.2.7 The initial mediation meeting between the Parties and the mediator shall be held within twenty (20) days after the Mediation Notice. Either Party may terminate the mediation process upon the earlier to occur of (A) the failure of the initial mediation meeting to occur within twenty (20) days after the date of the Mediation Notice, (B) the passage of thirty (30) days from the date of the Mediation Notice without the dispute having been resolved, or (C) such time as the mediator makes a finding that there is no possibility of resolution through mediation. The mediation shall follow and be governed by the laws of the State of New York.

15.2.8 All deadlines specified in this Section 15.2 may be extended by mutual agreement.

15.3 <u>Choice of Forum</u>. Each Party irrevocably consents and agrees that any legal action or proceeding arising out of this Agreement or the actions of the Parties leading up to the Agreement shall be brought exclusively in the United States District Court for the District of Oregon, Portland Division. By execution and delivery of this Agreement, each Party (a) accepts the exclusive jurisdiction of such court and waives any objection that it may now or hereafter have to the exercise of personal jurisdiction by such court over each Party, (b) irrevocably agrees to be bound by any final judgment (after any and all appeals) of any such court arising out of such documents or actions, (c) irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of venue of any suit, action or proceedings arising out of such documents brought in such court (including any claim that any such suit, action or proceeding has been brought in an inconvenient forum), (d) agrees that service of process in any such action may be effected by mailing a copy thereof by registered or certified mail, postage prepaid, to such Party at its address as set forth in this Agreement, and (e) agrees that nothing in this Agreement shall affect the right to effect service of process in any other manner permitted by law.

15.4 Settlement Discussions. No statements of position or offers of settlement made in the course of the dispute resolution process described in this Section will be offered into evidence for any purpose in any litigation or arbitration between the Parties, nor will any such statements or offers of settlement be used in any manner against either Party in any such litigation or arbitration. Further, no such statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation or arbitration. At the request of either Party, any such statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

15.5 Waiver of Jury Trial. EACH PARTY KNOWINGLY, VOLUNTARILY, INTENTIONALLY AND IRREVOCABLY WAIVES THE RIGHT TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED ON THIS AGREEMENT, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT AND ANY AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER VERBAL OR WRITTEN) OR ACTIONS OF ANY PARTY TO THIS AGREEMENT. THIS PROVISION IS A MATERIAL INDUCEMENT TO EACH OF THE PARTIES FOR ENTERING INTO THIS AGREEMENT. EACH PARTY HEREBY WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT AND ANY OTHER AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY MATTER ARISING HEREUNDER OR THEREUNDER WITH ANY PROCEEDING IN WHICH A JURY TRIAL HAS NOT OR CANNOT BE WAIVED.

15.6 Equitable Remedies. In any action for specific performance or injunctive relief or other equitable relief, all expenses incurred by the prevailing party in such proceeding, including reasonable counsel fees, shall be awarded to the prevailing party in such proceeding. Seller agrees that it will not assert as a defense to Buyer's action for specific performance of, or injunctive or other equitable relief relating to, Seller's obligations hereunder that the amounts payable or paid by Seller in respect of liquidated damages constitute an adequate remedy for the breach of such obligation, and Seller hereby conclusively waives such defense. Seller shall at all times during the Term, own, lease, control, hold in its own name or be signatory to all Required Facility Documents (as the case may be) relating to the Facility to the extent necessary to prevent a material adverse effect on Buyer's right to specific performance or injunctive relief.

SECTION 16

GUARANTEED PERFORMANCE PARAMETERS

16.1 Guaranteed Heat Rate. Seller shall operate and maintain the Facility so as to achieve the Guaranteed Heat Rate in accordance with the provisions of **Exhibit Q**.

16.2 Guaranteed Start-Up Time. Seller shall operate and maintain the Facility so as to achieve the Guaranteed Start-Up Time in accordance with the provisions of **Exhibit Q**.

16.3 Guaranteed Ramp Rate. Seller shall operate and maintain the Facility so as to achieve the Guaranteed Ramp Rate in accordance with the provisions of **Exhibit Q**.

SECTION 17

MISCELLANEOUS

17.1 Several Obligations. Nothing contained in this Agreement shall be construed to create an association, trust, partnership or joint venture or to impose a trust, partnership or fiduciary duty, obligation or liability on or between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

17.2 Choice of Law. This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules that may direct the application of the laws of another jurisdiction.

17.3 Partial Invalidity. The Parties do not intend to violate any Requirements of Law governing the subject matter of this Agreement. If any of the terms of this Agreement are finally held or determined to be invalid, illegal or void as being contrary to any Requirements of Law or public policy, all other terms of the Agreement shall remain in effect. The Parties shall use best efforts to amend this Agreement to reform or replace any terms determined to be invalid, illegal or void, such that the amended terms (a) comply with and are enforceable under Requirements of Law, (b) give effect to the intent of the Parties in entering into this Agreement, and (c) preserve the balance of the equities contemplated by this Agreement in all material respects.

17.4 Waiver. No waiver of any provision of this Agreement shall be effective unless the waiver is set forth in a writing that (a) expressly identifies the provision being waived, and (b) is signed by the Party waiving the provision. A Party's waiver of one or more failures by the other Party in the performance of any of the provisions of this Agreement shall not be construed as a waiver of any other failure or failures, whether of a like kind or different nature.

17.5 Governmental Jurisdiction and Authorizations. This Agreement is subject to the jurisdiction of those Governmental Authorities having control over either Party or this Agreement. Buyer's duty to comply with this Agreement is conditioned on Seller's submission to Buyer before the Commercial Operation Date and maintaining thereafter copies of all Required Facility Documents.

17.6 Restriction on Assignments. Except as expressly provided in Section 17.7, neither Party shall assign this Agreement or any of its rights or obligations under this Agreement without the prior written consent of the other Party.

17.7 Permitted Assignments. Buyer may assign its rights, delegate its duties or otherwise transfer its interests hereunder, in whole or in part to another entity having a long-term credit rating assigned thereto by a "nationally recognized statistical rating organization" (as that term is used in Rule 15c3-1(c)(2)(vi)(F) under the Securities Exchange Act of 1934) that equals or exceeds Buyer's long term credit rating as of the date of such assignment.

17.8 Entire Agreement. This Agreement (including all attached Exhibits, which are incorporated by this reference) supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding the subject matter of this

Agreement. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

17.9 Amendments. This Agreement shall not be altered or amended except by an instrument in writing specifically identifying the provisions to be amended and executed by authorized representatives of both parties.

17.10 No Third Party Beneficiaries. Notwithstanding anything to the contrary herein, this Agreement does not confer any rights upon any person other than the parties and their respective successors and permitted assigns. There are no third party beneficiaries of this Agreement.

17.11 Agents and Subcontractors. This Agreement may be performed by Buyer through the use of agents and subcontractors (but such use shall not relieve Buyer of any obligation hereunder).

17.12 Notices. All notices, requests, statements or payments shall be (a) made to the addresses set forth below, (b) in writing, and (c) delivered by letter, facsimile or other documentary form. Notice by facsimile or hand delivery shall be deemed to have been received by the close of the Business Day during which the notice is received or hand delivered. Notice by overnight mail or courier shall be deemed to have been received upon delivery as evidenced by the delivery receipt.

To Seller:	____________________ ____________________ ____________________
with a copy to:	____________________ ____________________ ____________________
To Buyer:	PacifiCorp 825 NE Multnomah, Suite 2000 Portland, Oregon 97232-2315 Attn: Sr. Vice President, Commercial & Trading
with copies to:	PacifiCorp 825 NE Multnomah, Suite 600 Portland, Oregon 97232-2315 Attn: Director of Contract Administration, Commercial & Trading

The Parties may change any of the persons to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section.

17.13 Mobile-Sierra. The rates for service specified in this Agreement shall remain in effect until expiration of the Term, and shall not be subject to change for any reason, including regulatory review, absent agreement of the parties. Neither Party shall petition FERC pursuant to the provisions of sections 205 or 206 of the Federal Power Act (16 U.S.C. § 792 et seq.) to amend such prices or terms, or support a petition by any other person seeking to amend such prices or terms, absent the agreement in writing of the other Party. Further, absent the agreement in writing by both Parties, the standard of review for changes to this Agreement proposed by a Party, a non-party or the FERC acting *sua sponte* shall be the "public i terest" application of the "just and reasonable" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and clarified by *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1 of Snohomish*, 554 U.S. __ , 128 S. Ct. 2733 (2008) and *NRG Power Mktg., LLC v. Maine Pub. Util. Comm'n*, __ U.S. __, __ S. Ct. __, N. 08-674 (2009).

17.14 Counterparts. This Agreement may be executed in two (2) or more counterparts, each of which is an original and all of which taken together constitute one and the same instrument.

[SIGNATURES ON NEXT PAGE]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed in their respective names as of the date first above written.

[SELLER],
as Seller

By: ______________________________

Name: ______________________________

Title: ______________________________

PACIFICORP,
as Buyer

By: ______________________________

Name: ______________________________

Title:

EXHIBIT T

FORM OF LENDER CONSENT

This CONSENT AND AGREEMENT (this "Consent"), dated as of ________, 200__, is entered into by and among PacifiCorp, an Oregon corporation, acting in its merchant function capacity (together with its permitted successors and assigns, "PacifiCorp"), _________________, in its capacity as [Administrative Agent] for the Lenders referred to below (together with its successors, designees and assigns in such capacity, "Administrative Agent"), and ___________, a _________ formed and existing under the laws of the State of ________ (together with its permitted successors and assigns, "Borrower"). Unless otherwise defined, all capitalized terms have the meaning given in the Contract (as hereinafter defined).

RECITALS

A. Borrower intends to develop, construct, install, test, own, operate and use an approximately ___ MW electric generating facility located _____________, known as the __________ Generation Project (the "Project").

B. In order to partially finance the development, construction, installation, testing, operation and use of the Project, Borrower has entered into that certain [Financing Agreement,] dated as of ________ (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Financing Agreement"), among Borrower, the financial institutions from time to time parties thereto (collectively, the "Lenders"), and Administrative Agent for the Lenders, pursuant to which, among other things, Lenders have extended commitments to make loans and other financial accommodations to, and for the benefit of, Borrower.

C. Borrower anticipates that, prior to the completion of construction of the Project; it will seek an additional investor (the "Tax Investor") to make an investment in Borrower to provide additional funds to finance the operation and use of the Project. [if applicable]

D. PacifiCorp and Borrower have entered into that certain Power Purchase Agreement, dated as of _____________ (collectively with all documents entered into in connection therewith that are listed on [Schedule A] attached hereto and incorporated herein by reference, as all are amended, amended and restated, supplemented or otherwise modified from time to time in accordance with the terms thereof and hereof, the "Contract").

E. Pursuant to a security agreement executed by Borrower and Administrative Agent for the Lenders (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Security Agreement"), Borrower has agreed, among other things, to assign, as collateral security for its obligations under the Financing Agreement and related documents (collectively, the "Financing Documents"), all of its right, title and interest in, to and under the Contract to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents.

AGREEMENT

NOW THEREFORE, for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be legally bound, the parties hereto hereby agree as follows:

SECTION 1. CONSENT TO ASSIGNMENT. PacifiCorp acknowledges the assignment referred to in Recital E above, consents to an assignment of the Contract pursuant thereto, and agrees with Administrative Agent as follows:

(A) Administrative Agent shall be entitled (but not obligated) to exercise all rights and to cure any defaults of Borrower under the Contract, subject to applicable notice and cure periods provided in the Contract. Upon receipt of notice from Administrative Agent, PacifiCorp agrees to accept such exercise and cure by Administrative Agent if timely made by Administrative Agent under the Contract and this Consent. Upon receipt of Administrative Agent's written instructions, PacifiCorp agrees to make directly to Administrative Agent all payments to be made by PacifiCorp to Borrower under the Contract from and after PacifiCorp's receipt of such instructions, and Borrower consents to any such action.

(B) PacifiCorp will not, without the prior written consent of Administrative Agent (such consent not to be unreasonably withheld), (i) cancel or terminate the Contract, or consent to or accept any cancellation, termination or suspension thereof by Borrower, except as provided in the Contract and in accordance with subparagraph 1(C) hereof, (ii) sell, assign or otherwise dispose (by operation of law or otherwise) of any part of its interest in the Contract, except as provided in the Contract, or (iii) amend or modify the Contract in any manner materially adverse to the interest of the Lenders in the Contract as collateral security under the Security Agreement. Any purported termination, cancellation or assignment which is not in compliance with this Section 1(B) shall be void which shall be the sole remedy under this Consent for such action.

(C) PacifiCorp agrees to deliver duplicates or copies of all notices of default delivered by PacifiCorp under or pursuant to the Contract to Administrative Agent in accordance with the notice provisions of this Consent. PacifiCorp may deliver any such notices concurrently with delivery of the notice to Borrower under the Contract. Administrative Agent shall have: (a) the same period of time to cure the breach or default that Borrower is entitled to under the Contract if such default is the failure to pay amounts to PacifiCorp which are due and payable by Borrower under the Contract, except that if PacifiCorp does not deliver the default notice to Administrative Agent concurrently with delivery of the notice to Borrower under the Contract, then as to Administrative Agent, the applicable cure period under the Contract shall begin on the date on which the notice is given to Administrative Agent, or (b) ninety (90) days from the date notice of default or breach is delivered to Administrative Agent to cure such default if such breach or default cannot be cured by the payment of money to PacifiCorp, so long as Administrative Agent continues to perform any monetary obligations under the Contract, Section 11.1.2(c) of the Contract is not being breached, and all other obligations under the Contract are performed by Borrower or Administrative Agent or its designees or assignees. If possession of the Project is necessary to cure such breach or default, and Administrative Agent or its designees or assignees declare Borrower in default and commence foreclosure proceedings, Administrative Agent or its designees or assignees will be allowed a reasonable period to complete such proceedings. PacifiCorp consents to the transfer of Borrower's interest under the Contract to the Lenders or Administrative Agent or their designees or assignees or any of them or a purchaser or grantee pursuant to the terms of the Financing Documents upon enforcement of such security at a foreclosure sale by judicial or nonjudicial foreclosure and sale or by a conveyance by Borrower in lieu of foreclosure and agrees that upon such foreclosure, sale or conveyance, PacifiCorp shall recognize the Lenders or Administrative Agent or their designees or assignees or any of them or other purchaser or grantee as the applicable party under the Contract (provided that such Lenders or Administrative Agent or their designees or assignees or purchaser or grantee assume the obligations of Borrower under the Contract, including, without limitation, satisfaction and compliance with all requirements of Sections 8.1 and 8.2 of the Contract, and provided further that PacifiCorp's subordinated lien rights with respect to the Project are preserved in the event of any transfer of Borrower's interest under the Contract).

(D) Notwithstanding subparagraph 1(C) above, in the event that the Contract is rejected by a trustee or debtor-in-possession in any bankruptcy or insolvency proceeding, or if the Contract is terminated for any reason other than a default which could have been but was not cured by Administrative Agent or its designees or assignees as provided in subparagraph 1(C) above, and if, within forty-five (45) days after such rejection or termination, the Lenders or their successors or assigns shall so request, to the extent permitted by applicable law, PacifiCorp and the Lenders or Administrative Agent or their designees or assignees will enter into a new contract. Such new contract shall be on the same terms and conditions as the original Contract for the remaining term of the original Contract before giving effect to such termination, and shall require the Lenders or Administrative Agent or their designees or assignees to cure any payment defaults then existing under the original Contract.

(E) In the event Administrative Agent, the Lenders or their designees or assignees elect to perform Borrower's obligations under the Contract as provided in subparagraph 1(C) above or enter into a new contract as provided in subparagraph 1(D) above, the recourse of PacifiCorp against Administrative Agent, Lenders or their designees and assignees shall be limited to such parties' interests in the Project, the credit support required under Section 7 of the Contract, and recourse against the assets of any party or entity that assumes the Contract or that enters into such new contract.

(F) In the event Administrative Agent, the Lenders or their designees or assignees succeed to Borrower's interest under the Contract, Administrative Agent, the Lenders or their designees or assignees shall cure any then-existing payment and performance defaults under the Contract, except any performance defaults of Borrower itself which by their nature are not susceptible of being cured. Administrative Agent, the Lenders and their designees or assignees shall have the right to assign all or a pro rata interest in the Contract or the new contract entered into pursuant to subparagraph 1(d) above to a person or entity to whom Borrower's interest in the Project is transferred, provided such transferee assumes the obligations of Borrower under the Contract. Upon such assignment, Administrative Agent and the Lenders and their designees or assignees (including their agents and employees, but excluding Seller) shall be released from any further liability thereunder accruing from and after the date of such assignment, to the extent of the interest assigned.

SECTION 2. REPRESENTATIONS AND WARRANTIES [PacifiCorp shall have the right to qualify the factual information contained in this Section to ensure that such representation is a true statement as of the date of this Consent]

PacifiCorp, acting in its merchant function capacity (and therefore specifically excluding the knowledge of PacifiCorp, acting in its transmission function capacity ("PacifiCorp Transmission"), as to any of the matters stated below, and without imputation to PacifiCorp of any knowledge whatsoever relating to the PacifiCorp Transmission, whether as a result of information publicly posted to the open access same-time information system or otherwise), hereby represents and warrants that as of the date of this Consent:

(A) It (i) is a corporation duly formed and validly existing under the laws of the state of its organization, (ii) is duly qualified, authorized to do business and in good standing in every jurisdiction necessary to perform its obligations under this Consent, and (iii) has all requisite corporate power and authority to enter into and to perform its obligations hereunder and under the Contract, and to carry out the terms hereof and thereof and the transactions contemplated hereby and thereby;

(B) the execution, delivery and performance of this Consent and the Contract have been duly authorized by all necessary corporate action on its part and do not require any approvals, material filings with, or consents of any entity or person which have not previously been obtained or made;

(C) each of this Consent and the Contract is in full force and effect;

(D) each of this Consent and the Contract has been duly executed and delivered on its behalf and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms, except as the enforceability thereof may be limited as set forth in Section 3.1.5 of the Contract;

(E) there is no litigation, arbitration, investigation or other proceeding pending for which PacifiCorp has received service of process or, to PacifiCorp's actual knowledge, threatened, against PacifiCorp relating solely to this Consent or the Contract and the transactions contemplated hereby and thereby;

(F) the execution, delivery and performance by it of this Consent and the Contract, and the consummation of the transactions contemplated hereby, will not result in any violation of, breach of or default under any term of (i) its formation or governance documents, or (ii) any material contract or material agreement to which it is a party or by which it or its property is bound, or of any material Requirements of Law presently in effect having applicability to it, the violation, breach or default of which could have a material adverse effect on its ability to perform its obligations under this Consent;

(G) neither PacifiCorp nor, to PacifiCorp's actual knowledge, any other party to the Contract, is in default of any of its obligations thereunder;

(H) to the best of PacifiCorp's actual knowledge, (i) no Force Majeure Event exists under, and as defined in, the Contract and (ii) no event or condition exists which would either immediately or with the passage of any applicable grace period or giving of notice, or both, enable either PacifiCorp or Borrower to terminate or suspend its obligations under the Contract; and

(I) the Contract and the documents and instruments contemplated therein and this Consent are the only agreements between Borrower and PacifiCorp with respect to the Project. [Reference to subordinated lien documents per Section 7.3 of the Contract to be inserted.]

Each of the representations and warranties set forth herein shall survive the execution and delivery of this Consent and the consummation of the transactions contemplated hereby.

SECTION 3. NOTICES. All notices required or permitted hereunder shall be in writing and shall be effective (a) upon receipt if hand delivered, (b) upon telephonic verification of receipt if sent by facsimile and (c) if otherwise delivered, upon the earlier of receipt or three (3) Business Days after being sent registered or certified mail, return receipt requested, with proper postage affixed thereto, or by private courier or delivery service with charges prepaid, and addressed as specified below:

If to PacifiCorp: [______________________] [______________________] [______________________] Telephone No.: [______________] Telecopy No.: [______________] Attn: [__________________]
If to Administrative Agent: [______________________] [______________________] [______________________] Telephone No.: [______________] Telecopy No.: [______________] Attn: [__________________]
If to Borrower: [______________________] [______________________] [______________________] Telephone No.: [______________] Telecopy No.: [______________] Attn: [__________________]

Any party shall have the right to change its address for notice hereunder to any other location within the United States by giving thirty (30) days written notice to the other parties in the manner set forth above. Further, the Tax Investor shall be entitled to receive notices from PacifiCorp by providing written notice to PacifiCorp of Tax Investor's address for notices. PacifiCorp's failure to provide any notice to the Tax Investor shall not be a breach of this Consent.

SECTION 4. ASSIGNMENT, TERMINATION, AMENDMENT AND GOVERNING LAW. This Consent shall be binding upon and benefit the successors and assigns of the parties hereto and the Tax Investor and their respective successors, transferees and assigns (including without limitation, any entity that refinances all or any portion of the obligations under the Financing Agreement). PacifiCorp agrees (a) to confirm such continuing obligation in writing upon the reasonable request of (and at the expense of) Borrower, Administrative Agent, the Lenders or any of their respective successors, transferees or assigns, and (b) to cause any successor-in-interest to PacifiCorp with respect to its interest in the Contract to assume, in writing in form and substance reasonably satisfactory to Administrative Agent, the obligations of PacifiCorp hereunder. Any purported assignment or transfer of the Contract not in conjunction with the written instrument of assumption contemplated by the foregoing clause (b) shall be null and void. No termination, amendment, variation or waiver of any provisions of this Consent shall be effective unless in writing and signed by the parties hereto. This Consent shall be governed by the laws of the State of New York (without giving effect to the principles thereof relating to conflicts of law except Section 5-1401 and 5-1402 of the New York General Obligations Law).

SECTION 5. COUNTERPARTS. This Consent may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

SECTION 6. SEVERABILITY. In case any provision of this Consent, or the obligations of any of the parties hereto, shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions, or the obligations of the other parties hereto, shall not in any way be affected or impaired thereby.

SECTION 7. ACKNOWLEDGMENTS BY BORROWER. Borrower, by its execution hereof, acknowledges and agrees that notwithstanding any term to the contrary in the Contract, PacifiCorp may perform as set forth herein and that neither the execution of this Consent, the performance by PacifiCorp of any of the obligations of PacifiCorp hereunder, the exercise of any of the rights of PacifiCorp hereunder, or the acceptance by PacifiCorp of performance of the Contract by any party other than Borrower shall (1) release Borrower from any obligation of Borrower under the Contract, (2) constitute a consent by PacifiCorp to, or impute knowledge to PacifiCorp of, any specific terms or conditions of the Financing Agreement, the Security Agreement or any of the other Financing Documents, or (3) constitute a waiver by PacifiCorp of any of its rights under the Contract. Borrower and Administrative Agent acknowledge hereby for the benefit of PacifiCorp that none of the Financing Agreement, the Security Agreement, the Financing Documents or any other documents executed in connection therewith alter, amend, modify or impair (or purport to alter, amend, modify or impair) any provisions of the Contract. Borrower shall have no rights against PacifiCorp on account of this Consent.

IN WITNESS WHEREOF, the parties hereto by their officers thereunto duly authorized, have duly executed this Consent as of the date first set forth above.

PacifiCorp,
an Oregon corporation

By:
Name:
Title:

______________________,
a ____________________

By:
Name:
Title:

_______________________,
as Administrative Agent for the Lenders

By:
Name:
Title: