Report of the Utah Independent Evaluator Regarding PacifiCorp's Draft Renewable Request for Proposals (2017R RFP)

Docket No. 17-035-23

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Merrimack Energy Group, Inc.
26 Shipway Place
Charlestown, MA 02129
(781) 856-0007

Merrimack
Energy

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Executive Summary

Merrimack Energy Group, Inc. ("Merrimack Energy") was retained by the Public Service Commission of Utah ("Commission") to serve as Independent Evaluator ("IE") for PacifiCorp's 2017 Renewable Request for Proposals ("2017R RFP" or "2017 Renewable RFP"). One of the tasks (Task A7) required of the IE is to provide a written evaluation including recommendations to the Commission on approval of the proposed solicitation or modifications required for approval and the bases for the recommendations. This report is intended to meet that requirement.

Utah Code Section 54-17-101, known as the Energy Resource Procurement Act requires that an affected electric utility seeking to acquire or construct a significant energy resource shall conduct a solicitation process that is approved by the Commission. The Commission shall determine whether the solicitation process complies with this Chapter and whether it is in the public interest taking into account 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 electric utility located in the state.

The overall objective of the IE in this process is to ensure the solicitation process could reasonably be expected to be undertaken in a fair, consistent and unbiased manner and results in the selection of the best resource option(s) for customers in terms of price and risk. As a component of the first phase of the solicitation process (RFP Design Phase, i.e. review of the draft RFP and related documents) the objective of the IE is to ensure the RFP will lead to a fair, equitable and transparent process and that the key aspects of the RFP are consistent with Utah Admin. Code and industry standards. To accomplish these objectives the IE has undertaken the following activities:

- Reviewed the draft RFP documents;
- Met with PacifiCorp to discuss PacifiCorp's evaluation methodology and models, input assumptions for the solicitation process and Code of Conduct training and implementation;
- Submitted questions to PacifiCorp on aspects of the solicitation process and received responses from PacifiCorp on nearly 50 questions;
- Reviewed the comments filed by all interested parties;
- Based on our overall industry experience in serving as IE or a related role in other power procurement processes, assessed PacifiCorp's competitive procurement approach in the 2017 R RFP relative to Utah Admin. Code and industry practices.

The IE has prepared its comments in three areas: (1) comments and recommendations on major issues identified by multiple parties and recognized by the IE as important to the fairness and transparency of the process; (2) comments on the attached contracts, with emphasis on the Power Purchase Agreement ("PPA") and the Build-Transfer Agreement ("BTA") as a means of assessing the risk sharing provisions of a power purchase option versus utility ownership; and (3) comments on specific aspects of the RFP documents, including suggested formatting changes and revisions/modifications designed to make the document clearer to bidders.

Several parties raised issues with regard to components of the RFP. If these issues can be resolved to the satisfaction of the parties and the Commission, it is our view that approval of the 2017R RFP is a reasonable result after resolution of these issues or acceptance of suggested approaches for addressing key issues.

Based on Merrimack Energy's review of the RFP and related information, the conclusions and recommendations of the IE are presented as follows:

Conclusions

- The RFP documents and process are generally consistent with the Utah Admin. Code, Regulations and Statutes pertaining to the requirements for the design and development of the competitive bidding process. The IE believes that PacifiCorp has adequately addressed most of the requirements listed in the Statutes. However, under the current structure of the RFP it is not certain if the solicitation process will lead to the acquisition and delivery of electricity at the lowest reasonable cost to the retail customers. The IE and others have suggested revisions to the RFP which should hopefully result in a more competitive process that will verify the IRP action plan identified by PacifiCorp without extending the solicitation process schedule, which could jeopardize the potential benefits to customers;

- The integration of the wind generation resources in conjunction with a new 140-mile 500 kV transmission line from the Aeolus substation to the Bridger/Anticline substation (Aeolus to Bridger/Anticline transmission line) could pose risks to bidders and consumers if the transmission project is not built on time to allow bidders or benchmark resources to achieve Production Tax Credit ("PTC") benefits;

- The 2017R RFP is a reasonably transparent RFP, with a significant amount of information provided to bidders on which the bidders could base their proposals;

- The 2017R RFP is designed to provide the same information to all bidders including the benchmark options;

- The products sought in this RFP are clearly defined and the information required for each type of resource alternative is specified in the RFP in a clear and concise manner;

- The RFP documents clearly describe the products requested, the requirements of bidders, the evaluation and selection process, and the risk profile of the buyer. In this regard, there is sufficient information to allow bidders to assess whether or not to compete, the product of choice to bid to be most competitive, and the process by which their proposals will be evaluated;

- There are a number of safeguards included in the solicitation process which should ensure that all bidders will have access to the same information at the same time with no undue benefit for the benchmark bids;

- Parties have raised the issue of ensuring comparability for resource evaluation, notably ensuring that utility benchmarks and third-party PPA and Build Transfer bids are required to compete based on the same set of rules or on a level playing field. The IE also views comparability to be the most challenging issue in a solicitation process in which utility-owned resources compete with third-party resources. The nature of these resources is very different to begin with. Third-party PPA options submit a price schedule that is firm at the time of submission. Changes in the cost of equipment or market prices can affect the final economics either positively or negatively, with the bidder absorbing the risk of higher project costs or enjoying the benefits or lower project costs. Utility-owned options, on the other hand are submitted as reasonable estimates. If costs increase, the utility could request the ability to pass through the costs to customers assuming the costs are deemed to be prudently incurred. Cost decreases, on the other hand, are passed through to customers. Given the different risk profiles, contract terms, etc. it is extremely difficult to create a fully level playing field on which both types of resources can compete. Merrimack Energy has proposed several ways to create a more level playing field in the solicitation process.

- The evaluation process and quantitative methodologies developed by PacifiCorp for undertaking the initial price screening evaluation (spreadsheet model formerly referred to as RFP Base Model) and for selecting the final short list (System Optimizer and PaR models) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the model methodology is consistent with and likely exceeds industry standards applied by others for conducting such a price and risk analysis. While the spreadsheet model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others, notably a comparison of the costs and benefits for each proposal. The portfolio evaluation and risk assessment methodologies are very detailed and are generally pertinent to the requirements of the Energy Procurement Resource Act.

- The evaluation and selection process is a comprehensive process designed to evaluate the cost implications associated with different resource portfolios, the important non-price factors required in the Act that influence project viability, and assesses the risk parameters associated with the portfolios.

- PacifiCorp met the requirements of Utah Admin. Code R746-420-1(2) and the Scheduling Order in Docket No. 17-035-23 by providing the IE with data, information and models necessary for the IE to analyze and verify the models. PacifiCorp provided the IE with the latest version of its price screening spreadsheet model that will be used for the phase 1 shortlist evaluation as well as the latest input assumptions, which may be subject to revisions.

Recommendations

- Both Merrimack Energy and UAE have raised issues with regard to comparability associated with the risk issues allocated to each resource type (i.e. PPA, BTA, and benchmark) and comparability associated with the resources evaluation process (contract term/evaluation horizon). Merrimack Energy has undertaken a detailed assessment of the Power Purchase Agreement ("PPA") and Build Transfer Agreements ("BTA") and identifies the risks in each contract. Merrimack Energy concludes that there are very different risk provisions in the PPA and BTA agreements which could unduly favor the Benchmark options. PPA and BTA bidders are allocated significant risk which could either eliminate potential bid options or lead to much higher prices for these options if the bidder prices the risk into its bid price. We suggest that PacifiCorp either revise the contracts to create a more balanced risk profile or allow bidders to provide comments on contract issues with their proposals. For example, in response to a question from Merrimack Energy regarding contract risk allocation, PacifiCorp stated that the contracts will be subject to negotiations, apparently meaning that PacifiCorp is willing to recognize that bidders may take exception with certain provisions of the contracts. The IE has suggested that bidders be allowed to either red-line the PPA or provide comments on the Agreements with their proposals to assess if there are 'deal breaker" provisions in the contracts that will affect all or a significant portion of the bidders. PacifiCorp could then decide to make revisions to the contracts in conjunction with input from the IEs to ensure the contract provisions do not unduly bias a resource selection decision;

- The IE has also provided recommendations associated with meeting the requirements in the statute for equivalent contract terms. Section R746-420-3(8)(k) states that the solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark option, which we understand to be 30 years. The recommendation of the IE is to allow PPA bidders to offer either a 30-year term or a 20-year contract with up to a 10-year extension that is a firm price and would be exercised at the option of the buyer;

- Merrimack Energy has also recommended that the eligibility provisions in the RFP be expanded. This includes removing the requirement that only new wind projects who can quality for the full PTC benefits are eligible. Instead, the IE supports PacifiCorp's recent decision to lift the full PTC requirement and allow other bidders that may also have unique competitive advantages to compete. The IE also recommends that existing projects that are not under contract at the time of bid submission and who propose repowering their wind projects are also eligible to bid. Finally, the IE agrees with the Division of Public Utilities regarding the proposal to allow broader access to PacifiCorp's load center by eliminating the requirement in the Draft RFP that the bidder must use the proposed Aeolus to Bridger/Anticline ("Gateway Segment D2" or "D2") transmission facilities or demonstrate they can deliver the power into Wyoming. This will allow

PacifiCorp to determine if its action plan for 1,270 MW of wind generation combined with construction of the transmission facilities associated with Aeolus to Bridger/Anticline transmission line are economic and provide value to customers;

- Merrimack Energy recommends that the Commission grant PacifiCorp's request for a waiver of the bid binding requirements in the Statute (Utah Admin. Code R746-420-3(10)(a). However, the IE still suggests that questions and answers will be blinded in that PacifiCorp will not know the identity of the bidder when the questions from the bidder is provided to them by the IE. Merrimack Energy will remove the name or reference to the bidder prior to submitting the question to PacifiCorp for a response;

- The IE recommends that PacifiCorp allow bidders to submit a base bid and two alternatives for the bid fee of $10,000 instead of the base bid and one alternative, particularly since PacifiCorp is encouraging PPA bidders to include a purchase option proposal with their bid. If bidders offer a purchase option presumably this will serve to use up their one allowable alternative;

- Given the importance of transmission, the IE suggests that PacifiCorp consider either providing a workshop on transmission and interconnection requirements and status of options or include a detailed discussion of these issues as part of the Bidders Conference to be held on September 12, 2017;

- The IE suggests that PacifiCorp consider revising its non-price factors to include project viability characteristics for the projects. In our view, some of the factors identified by PacifiCorp are really eligibility or threshold criteria (i.e. bids provide all required RFP information) and not non-price factors. We have identified factors such as experience of the bidder, access to generating equipment, financing plan, O&M plan, etc. as criteria or factors to consider;

- There is little information regarding credit requirements to allow bidders to reflect the credit requirements in their bids or affect their decision to compete, unlike previous PacifiCorp RFPs. PacifiCorp could either include credit requirements based on $/kW bid or update its previous credit methodology;

- The IE recognizes the potential issues associated with new lease accounting rules and Variable Interest Entity (VIE) treatment, particularly since PacifiCorp has stated in the RFP that it will not be subject to projects that trigger VIE treatment, for example. Merrimack Energy included language in this section of the RFP to require PacifiCorp to provide documentation to the IE justifying any decision to reject a bid due to accounting issues;

- Task B3 of the IE Scope of Work as listed in the Commission's RFP for Independent Evaluator requires the IE to set up and maintain a webpage or database for information exchange between bidders/potential bidders and PacifiCorp **only if directed by the PSC in its Approval of the Solicitation Process.** Merrimack Energy proposed to establish a webpage on its website to accommodate this requirement similar to the webpages we established for previous PacifiCorp RFPs. The webpage will be used to accept questions from bidders, which Merrimack Energy staff will blind by removing the name of the bidder, before sending the questions to PacifiCorp for a response. Merrimack Energy will then review the responses and post the Question and Answer to the webpage for bidders to review. Merrimack Energy will also post any RFP documents on the webpage as well as posting any Notices to bidders of upcoming schedule items or changes to RFP documents.

I. Introduction

Merrimack Energy Group, Inc. (Merrimack Energy) was retained by the Public Service Commission of Utah ("Commission" or "PSC") to serve as Independent Evaluator for PacifiCorp's 2017 Renewable Resources RFP ("2017R RFP" or "Renewable RFP"). The scope of work for the assignment requires the Independent Evaluator (IE) to participate in all three phases of the solicitation process: (1) RFP design and solicitation process approval; (2) Solicitation process bid monitoring and evaluation and (3) Energy resource decision approval process. The specific tasks for the Independent Evaluator under each phase of the solicitation process as listed in Merrimack Energy's contract with the Commission are listed below. The specific tasks outlined will guide the activities of the Independent Evaluator throughout the solicitation process.

<u>Solicitation Process Approval</u>

1. Review PacifiCorp's proposed solicitation process to assure it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to PacifiCorp's retail customers taking into consideration long-term and short-term impacts, risk, reliability and the financial impacts on PacifiCorp;

2. Review PacifiCorp's proposed solicitation process to assure the evaluation criteria, methods and computer models are sufficient to evaluate the benchmark option and prospective bids in a manner that is fair, unbiased and comparable, to the extent practicable, and that the evaluation tools will be sufficient to determine the best alternative for PacifiCorp's retail customers;

3. Review the adequacy, accuracy and completeness of all proposed solicitation materials to ensure that paragraph 1 objectives are achieved. The solicitation materials include: disclosure information, bid templates, disclosure of evaluation criteria, methods, and models;

4. Review, analyze and validate the benchmark options, (including cost assumptions) for adequacy, accuracy, completeness, reasonableness, and consistency with the solicitation process;

5. Provide input on the development of screening and evaluation criteria, ranking factors, and evaluation methods. Ensure that screening and evaluation criteria take into consideration the assumptions included in PacifiCorp's most recent IRP, any recently filed IRP Update, any PSC order on the IRP or IRP Update, and in its Benchmark Option(s);

6. Facilitate and monitor communications between PacifiCorp and bidders;

7. Provide monthly status reports to the Commission, DPU, and PacifiCorp on all aspects of the solicitation approval process as it progresses;

8. Provide a written evaluation including recommendations to the Commission regarding the results of the above tasks. Include recommendations on approval of the proposed solicitation or modifications required for approval and the bases for recommendations;

9. Testify before the Commission regarding approval of the proposed solicitation, if necessary.

2. Solicitation Process Bid Monitoring and Evaluation

1. Monitor, observe, validate, and offer feedback to PacifiCorp, the PSC and the DPU on all aspects of the solicitation process, including: the content of the solicitation; communications between bidders and PacifiCorp; evaluation and ranking of bid responses; creation and selection of the "short list" of bidders for more detailed analysis and negotiation; negotiations between short list bidders and PacifiCorp; ranking of the final list of alternatives; negotiation of proposed contracts with successful bidders; and selection of energy resource(s);

2. Document all substantive correspondence and communications with PacifiCorp and bidders;

3. Participate in the pre-bid conferences;

4. Only if directed by the PSC in its Approval of the Solicitation Process, set up and maintain a webpage or database for information exchange between bidders/potential bidders and PacifiCorp. This webpage or database must include all solicitation materials and questions submitted by bidders along with the corresponding responses;

5. Review and evaluate benchmark costs and the treatment of benchmark bid(s) and assess whether the benchmark(s) are considered and evaluated in the same way as all other bids. File a report on the benchmark costs and treatment with the PSC and provide copies to the DPU and PacifiCorp;

6. Participate in the receipt of bids; issue bid numbers before submittal to PacifiCorp for evaluation and ensure all bids are treated in a fair and non-discriminatory manner;

7. If required, serve as the primary conduit for bidders to submit pre-blinded bids; ensure all bids are appropriately blinded as required;

8. Monitor all communications with bidders after receipt of bids and monitor negotiations conducted by PacifiCorp and any short-listed bidders;

9. Monitor and audit the evaluation process and validate that evaluation criteria, methods, models and other solicitation processes have been applied as approved by the Commission and consistently and appropriately applied to all bids and the benchmark option. Audit the bid evaluations to verify that assumptions, inputs, outputs and results are appropriate and reasonable. Analyze, operate, and validate all important models, modeling techniques, assumptions and inputs;

10. Advise the Commission, Division and PacifiCorp of any issue that might reasonably be construed to affect the integrity of the solicitation process and provide PacifiCorp an opportunity to remedy the defect identified. Advise the Commission and DPU of significant changes or unresolved issues as they arise;

11. Provide monthly status reports to the PSC, the DPU and PacifiCorp on all aspects of the solicitation process as it progresses noting any deficiencies in the preparation of solicitation materials, maintenance of records, communications with bidders, in evaluating or selecting bids, or negotiations with bidders;

12. Within approximately two weeks of PacifiCorp's selection of the final short list, provide a draft report with the Commission and Division detailing the methods and results of PacifiCorp's initial screening and full evaluation of all bids. Include a description of the bids, selection criteria, the basis for the selection of the short-listed bids and rationale for eliminating bids. Within approximately one week of receipt of comments on the report, modify and file the report with the PSC and provide a copy to the DPU;

13. Monitor all aspects of the negotiation process, including: communications between short list bidders and PacifiCorp; and proposed contract revisions. Provide input to PacifiCorp on the negotiation of proposed contracts with successful bidders or on other matters, consistent with the statute.

<u>3. Participation in the Energy Resource Decision Approval Process</u>

1. File a detailed final report (confidential and public versions) with the Commission and provide a copy to the Division within 21 days of PacifiCorp's final ranking of bids and identification of its Energy Resource Decision;

2. If requested, meet with the PSC to discuss the Final Report;

3. Participate in any Utah technical conferences related to the Energy Resource Decision Approval Process;

4. Testify during the Energy Resource Decision Approval Process in Utah.

Utah Law Regarding Competitive Bidding

Utah State Law 54-17-101, known as the Energy Resource Procurement Act (2005) requires that an affected electric utility seeking to acquire or construct a significant energy resource[1] shall conduct a solicitation process that is approved by the Commission. The Commission shall determine whether the solicitation process complies with this chapter and whether it is in the public interest taking into consideration 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 electric utility located in the state.

Rule R746-420 – Requests for Approval of a Solicitation Process outlines in detail the requirements of a solicitation process with regard to implementation of the Energy Resource Procurement Act. Among other issues, Rule R746-420 provides general provisions regarding the filing requirements for the soliciting utility in seeking approval of the solicitation, a description of the solicitation process and associated requirements, and the roles and responsibilities of an Independent Evaluator to oversee the solicitation process.

According to R746-420-3, all aspects of the Solicitation and Solicitation Process must be fair, reasonable and in the public interest. A proposed Solicitation and Solicitation Process must be reasonably designed to:

- Comply with all applicable requirements of the Act and Commission Rules;
- Be in the public interest taking into consideration:
    - Whether they are reasonably designed to lead to the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of the Soliciting Utility located in the state
    - Long-term and short-term impacts
    - Risk
    - Reliability
    - Financial impacts on the Soliciting Utility; and
    - Other factors determined by the Commission to be relevant;
- Be sufficiently flexible to permit the evaluation and selection of those resources or combination of resources determined by the Commission to be in the public interest;
- Be designed to solicit a robust set of bids to the extent practicable; and
- Be commenced sufficiently in advance of the time of the projected resource need to permit and facilitate compliance with the Act and the Commission rules and a reasonable evaluation of resource options that can be available to fill the projected need.

The specific requirements for the solicitation process are included in Section R746-420-3 of the Rules. The key provisions by topic area in the rules are identified and briefly summarized below.

[1] A significant energy resource is defined as a resource that consists of a total of 100 MW or more of new generating capacity that has a dependable life of ten years or more.

(1) ***General Objectives and Requirements of the Solicitation Process*** – Requires that the solicitation process must be fair, reasonable and in the public interest and be designed to lead to the acquisition of electricity at the lowest reasonable cost to retail customers in the state;

(2) ***Screening Criteria – Screening in a Solicitation Process*** – The utility shall develop and utilize screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure the solicitation process is fair, reasonable and in the public interest in consultation with the IE and Division;

(3) ***Screening Criteria – Request for Qualification and Request for Proposals*** – The soliciting utility may use a Request for Qualification (RFQ) process;

(4) ***Disclosures – Benchmark Option*** – If a solicitation includes a Benchmark Option the utility is required to identify whether the Benchmark is an owned option or a purchase option. If the benchmark is an owned option, the utility should provide a detailed description of the facility, including operating and dispatch characteristics. The utility should also provide assurances that the Benchmark Option will be validated by the IE and that no changes to any aspect of the Benchmark Option will be permitted after the validation of the Benchmark Option by the IE and prior to the receipt of bids under the RFP and that the Benchmark option will not be subject to changes unless updates to other bids are permitted;

(5) ***Disclosures – Evaluation Methodolog***y – The solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids including all evaluation procedures, factors and weights, credit requirements, proforma contracts, and solicitation schedule;

(6) ***Disclosures – Independent Evaluator*** – The solicitation should describe the role of the IE consistent with Section 54-17-203 including an explanation of the role, contact information and directions for potential bidders to contact the IE with questions, comments, information and suggestions;

(7) ***General Requirements*** – The solicitation must clearly describe the nature and relevant attributes of the requested resource. The solicitation should identify the amounts and types of resources requested, timing of deliveries, pricing options, acceptable delivery points, price and non-price factors and weights, credit and security requirements, transmission constraints, etc.

(8) ***Process Requirements for a Benchmark Option*** – The benchmark team and evaluation team must have no direct communications; All relevant costs and characteristics of the Benchmark option must be audited and validated by the IE prior to receiving any of the bids; All bids must be considered and evaluated against the Benchmark option on a fair and comparable basis;

(9) ***Issuance of a Solicitation*** – The utility shall issue the solicitation promptly after Commission approval;

(10) ***Evaluation of Bids***– The IE shall have access to all information and resources utilized by the utility in conducting its analyses. The utility shall provide the IE with access to documents, data, and models utilized by the utility in its analyses; The IE shall monitor any negotiations with short listed bidders.

In addition to the Introduction, the report is presented in six other sections. Section II provides a brief background on PacifiCorp's Draft 2017R Renewable RFP process to date. Section III describes the key provisions of the initial Draft 2017R RFP. Section IV provides a summary of the positions on the parties in the case as presented in the comments filed by each party. Section V provides a detailed discussion of major/important competitive bidding issues and suggestions/recommendations for addressing the major RFP issues associated with the Draft 2017R Renewable RFP. Section VI provides a review and assessment of major contract issues, particularly the differences in contract risk considerations between a Power Purchase Agreement (PPA) and the Build-Transfer Agreement. Finally, Section VII provides our conclusions and recommendations.

II. Background

When evaluating and assessing the design of a competitive procurement process, Merrimack Energy, as Independent Evaluator generally conducts its assessment relative to a number of factors, including the following:

- Regulatory statutes or rules underlying the competitive procurement process in a specific state. For this solicitation, Utah Code and Regulations pertaining to competitive solicitation processes apply;
- The types of resources, products, and contract structures solicited;
- The objectives of the process;
- The fairness and transparency of the process; and
- The consistency with industry standards for similar types of solicitations.

For this type of solicitation, it is important that the RFP is structured such that all types of eligible resources have a reasonable opportunity to compete.

Criteria for an Effective Procurement Process

In assessing whether a competitive procurement process is likely to lead to a positive outcome which benefits customers, meets the objectives and criteria established, and is consistent with regulations and statutes, Merrimack Energy considers the following questions:

- Is the solicitation process fair, equitable, unbiased, and comprehensive for all bidders?
- Is the solicitation process reasonably transparent to Bidders?
- If applicable, does the solicitation process allow for a reasonably level playing field with regard to the evaluation of utility-ownership options and third-party proposals

- Will the process likely lead to positive benefits to utility customers?
- Is the process adequately designed to encourage broad participation from eligible bidders?
- Do the RFP documents adequately define the products solicited, the objectives of the process, bidding guidelines, the bidding requirements to guide bidders in preparing their bids, the bid evaluation and selection criteria of importance, and the risk factors important to the utility issuing the RFP?
- Are the contracts designed to provide a reasonable balance of risk relative to the objectives of the counterparties, seeking to minimize risk to utility customers while ensuring that projects can reasonably be financed and developed?
- Does the evaluation methodology identify how qualitative and quantitative measures are considered and are consistent with the defined metrics for evaluation and selection?
- Are there differences in the evaluation methods for different technologies that cannot be explained in a technology neutral manner?
- Does the quantitative evaluation methodology allow for consistent evaluation of bids of different sizes, technologies, products and in-service dates?

The application of a fair and transparent competitive procurement process is important for creating competition for the overall benefit of customers. Fairness generally means that all bidders are treated similarly, have access to the same information at the same time, and have equal opportunity of being successful in the process. A reasonable level of transparency[2] is also another important element leading to a successful solicitation process. Transparency means that there is a reasonable amount of information to guide bidders in preparing a complete proposal to meet utility requirements. Transparency is important with regard to the requirement that no party, particularly an affiliate, should have an informational advantage in any part of the solicitation. Reasonably transparent processes are those that provide information guidance and direction to bidders on the information required by the utility to evaluate their proposal, provide guidance on the bid evaluation criteria, bid evaluation and selection process. Fair and reasonably transparent processes should encourage competition among potential bidders who can adequately determine if they have the ability to effectively compete in the process and lead to more complete and comprehensive proposals. The greater the level of competition for all products sought by the utility the greater the chance for competitive options and lower prices for consumers.

Along with fairness and transparency, another issue of importance to bidders is the possibility for bias in the procurement process. Bias can take several forms such as design of a competitive procurement process in which bidders feel that the process unduly favors one type of resource over another. Bias can also come into play with regard to the application of the quantitative and qualitative evaluation processes such as quantitative methodologies that favor projects of different terms, sizes or in-service dates or different transaction types.

[2] Merrimack Energy always uses the term “a reasonable level of transparency” because a competitive procurement process is very rarely fully transparent. Bidders, for example, don’t have access to the utility’s models and data used to evaluate other proposals. Likewise, the utility generally doesn’t provide the detailed back-up information for all the criteria used to evaluate bids from a qualitative perspective.

Another consideration in assessing the integrity of the solicitation process is to assess whether the risk allocation associated with contracts for different types of resources or product types is reasonable. Ideally, all contract types and resource types would include provisions/conditions that allow for the same or very similar risk allocation to allow for a completely level playing field. However, in practice this is not inherently practical since different transaction types and resource types have different characteristics. For example, solar projects may have different characteristics than geothermal projects. Placing all of these options on a level playing field in terms of risk allocation and in evaluating bids is a real challenge.

Lastly, one of the key considerations is the level of comparability included in the evaluation process to ensure that all bids are evaluated fairly and placed on a level playing field. This principle is particularly important in cases where a utility-ownership option is competing against third-party options. This report will address the comparability issue in more detail later in the report.

III. Summary of the Key Provisions of the All Source RFP

This Chapter of the Report will provide a high-level description of the Draft 2017R RFP and the associated Appendices and Attachments.

On June 16, 2017, PacifiCorp (d/b/a Rocky Mountain Power) filed an application with the Utah Public Service Commission ("Commission") in Docket No. 17-035-23 requesting approval of a solicitation process for the 2017 Renewable Request for Proposals. The Application requests that the Commission issue an order approving the Company's 2017 Renewable Request for Proposals seeking up to approximately 1,270 of new wind resources capable of interconnecting to, and/or delivering energy and capacity across PacifiCorp's transmission system in Wyoming. A Scheduling Conference on the approval of the solicitation process was held on June 27, 2017, with a Scheduling Order issued by the Commission on June 28, 2017. PacifiCorp held a Pre-Issuance Bidders Conference on May 31, 2017, as required.

Based on the Schedule in this Docket, comments on the draft RFP were due on August 4, 2017 and the Report of the Independent Evaluator on the draft RFP is due on August 11, 2017.

The scope of the draft 2017R RFP is focused on PacifiCorp attempting to capture a time limited resource opportunity arising from the expiration of the federal production tax credits ("PTC") through procurement of proposed wind resources in conjunction with a new 140-mile, 500 kV transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming , to a new annex substation, Bridger/Anticline, located near the existing Jim Bridger substation ("Transmission Project"). The combination of wind generation and the transmission option proposed was determined by PacifiCorp to have positive value to customers as identified in its 2017 Integrated Resource Plan. Bidders could submit proposals under the following structures: (1) Power Purchase Agreement ("PPA") with or without a purchase option provided to PacifiCorp; (2) Build-Transfer structure in accordance with the terms of an Asset Purchase and Sale Agreement ("APSA"), and (3) a Bidder-proposed ownership structure.

The initial draft of the 2017R RFP was provided to the IE and posted on PacifiCorp's website on or around June 16, 2017. The draft RFP provided a detailed description of the resource alternatives sought by PacifiCorp, the logistics for submitting a bid including the information, forms, and schedules required with each type of resource alternative proposed, a description of the bid evaluation process and a description of the evaluation criteria to be used to evaluate and select bids. The draft RFP contains seventeen Appendices. In addition, there are Forms in the document for bidders to fill out and submit with their proposal. Finally, the draft RFP contains a description of the role of the Independent Evaluator in the bidding process, and a Code of Conduct.

Subsequent to submission of the draft RFP, the IE prepared a list of questions regarding the RFP and associated documents and sent the questions to PacifiCorp for review. PacifiCorp, members of the DPU staff, and the IE held a meeting in Salt Lake City on July 19, 2017 to discuss and observe PacifiCorp's Code of Conduct and training of employees who are subject to the Code of Conduct as well as discussing in detail PacifiCorp's evaluation methodology, models and input assumptions to prepare for the evaluation process.

Summary of the Key Provisions From the 2017R Draft RFP

As noted, PacifiCorp posted its 2017R RFP and related documents to the Utah PSC's website on June 16, 2017 in Docket No. 17-035-23. In addition to the RFP document, PacifiCorp provided a number of Appendices to the RFP with its filing. The Appendices to the RFP are listed below.

1. RFP Main Document
2. Appendix A – 2017R Renewable Project Technical Specification
3. Appendix B – Notice of Intent to Bid and Information Required in Bid Proposals
4. Appendix C – Bid Summary and Pricing Input Sheet (Instructions for PPA and BTA)
5. Appendix D – Bidder's Credit Information
6. Appendix E-1 – PPA Instructions to Bidders
7. Appendix E-2 – Power Purchase Agreement (PPA) Documents
8. Appendix F-1 – BTA Instructions to Bidders
9. Appendix F-2 – Build Transfer Agreement (BTA) Documents
10. Appendix G – Confidentiality Agreement and Non-Reliance Letter
11. Appendix H – Reserved
12. Appendix I – FERC's Standards of Conduct
13. Appendix J – Qualified Reporting Entity Services Agreement
14. Appendix K – General Services Contract - Operations and Maintenance Services for Project
15. Appendix L – PacifiCorp's Company Alternative (Benchmark Resource)
16. Appendix M – Role of the Independent Evaluator
17. Appendix N – Code of Conduct Governing PacifiCorp's Intra-Company Relationships for RFP Process
18. Appendix O – Description of PacifiCorp's Proposed Gateway Segment D Transmission Project

Exhibit 1 lists the key provisions in the 2017R Draft Renewable RFP included in Docket No.17-035-23 on the Commission website.

Exhibit 1
Summary of Key Provisions of the Draft 2017R RFP

RFP Characteristics	All Source RFP
Resource Requirements	PacifiCorp is seeking cost-effective bid for up to 1,270 MW of wind energy resources interconnecting with or delivering to PacifiCorp's Wyoming system.
Resource Timing – On-line Date	PacifiCorp will only consider projects that demonstrate a unique value opportunity for its customers and achieve commercial operation by December 31, 2020, without compromising system reliability.
Eligibility	PacifiCorp will accept proposals for new wind resources capable of directly interconnecting and delivering energy to PacifiCorp's network transmission system in Wyoming inclusive of the proposed 500-kV Gateway Segment D2 Aeolus to Bridger Anticline substation and transmission system, or capable of delivering energy into PacifiCorp's transmission system in Wyoming with the use of third-party firm transmission service. Proposals for new wind resources must demonstrate, to PacifiCorp's satisfaction, that projects will qualify for the full value of the federal PTC, if applicable. (Revised)
Resource Alternatives	Resource Alternatives include: (1) Power Purchase Agreement for a twenty-year term; (2) Power Purchase Agreement which can include an option to purchase the project during or at end of contract term to retain value of site for customers; (3) Build-Transfer Agreement whereby the bidder develops the project, assumes responsibility for construction and ultimately transfers the operating asset to PacifiCorp upon or prior to December 31,2020. PacifiCorp also plans to offer at least 860 MW of new wind projects as self-build options.
Bid Alternatives	Each bidder shall pay a bid fee of $10,000 for each base proposal and one alternative submitted. Bidders will also be allowed to offer up to three additional alternatives at a fee of $3,000 each. Alternatives will be limited to different bid sizes, contract terms, in-service dates, and/or pricing structures.
Bidding Process	The Company will conduct a multi-stage process. In the first stage, the bidder must submit both the "Intent to Bid Form" and the Bidder's Credit Information Appendices B and D). In the second stage, bidders

	are required to submit their proposals and respond to the requirements for the type of resource alternative they are proposing. All bidders must submit Appendix C – Bid Summary and Pricing Input Sheet. Bids that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices must be within 10% of the Bidders original total bid cost relative to the cost of the bid selected in the initial short list.
Utility Bid Options	The Company proposes to submit four individual wind Benchmark Resources to satisfy approximately 860 MW of targeted wind resources. A description of the projects is included in Appendix L.
Evaluation Process – Short List Selection	PacifiCorp proposes a two-phase price evaluation process, with multiple steps as will be described in more detail below. The two phases include (1) an Indicative Bid stage as the basis for selecting a short list and (2) Best and Final Offer. In the first phase, PacifiCorp will establish an initial shortlist based on both price and non-price factors, 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. Price will account for 80% of the score and non-price for 20% (or a maximum of 20 points). From a pricing perspective, all bids will be evaluated using PacifiCorp's proprietary spreadsheet model to calculate the delivered revenue requirement cost of each benchmark resource and market bid, inclusive of any applicable carry cost and net of production tax credit benefits. The delivered revenue requirement cost will be netted against energy, capacity, and terminal value benefits, as applicable, to calculate the net cost of each benchmark resource and market bid. The net cost calculation will be used to assign a price score to each benchmark resource and each market bid. This will be achieved by calculating the nominal levelized (discounted) revenue requirement cost and the nominal levelized (discounted) benefit for each benchmark resource and market bid, where revenue requirement costs are reported as a negative value and customer benefits are reported as a positive value. The calculated net benefit for each benchmark resource and market bid will be forced ranked based for the $/MWh price category with an upper boundary of 80 points. Forced ranked bids grant the maximum of 80 points to evaluated bids with the highest calculated net benefit and the lowest evaluated bid get 0 points. PacifiCorp will use the combined price and non-price results to rank benchmark resources and market bids. Based on these rankings, PacifiCorp will select an initial shortlist based on total bid score (maximum at 100%, with a maximum of 80% for price and a maximum of 20% for non-price factors). Bid that make the short list will be allowed to provide a Best and Final

	Offer. Best and Final pricing shall not exceed 10% of the original total bid cost, which PacifiCorp will assess on a present value revenue requirements basis. In the event that best and final pricing increases the total benchmark resource or market bid cost by more than 10%, PacifiCorp reserves the right to either (a) reject the best and final proposal or, (b) replace the shortlisted bid or bid alternative with a final proposal solicited from another bid not originally selected to the initial shortlist.
Non-Price Evaluation	In phase 1 of the evaluation process, price and non-price weights are combined to select the short list within each resource Category. The non-price characteristics include the same criteria as the previous RFP: Conformity to RFP requirements, Project Deliverability and Transmission Interconnection Progression.
Phase 2 – Final Shortlist	PacifiCorp will use the System Optimizer (SO) model to develop a resource portfolio containing the 2017R RFP bids with the Aeolus to Bridger/Anticline transmission project. For purposes of the 2017R RFP, the SO model will be used to select the combination of wind projects from the initial shortlist, up to approximately 1,270 MW, that minimizes system costs among a range of different environmental policy and market price scenarios. The SO model will also be used to establish least cost resource portfolios for each policy-price scenario without any new wind and without the Aeolus to Bridger/Anticline transmission project. PacifiCorp will also evaluate each of the resource portfolios developed with the SO model using Planning and Risk (PaR). For purposes of the 2017R RFP, PaR will be used to calculate the stochastic mean PVRR(d) and the risk-adjusted PVRR(d) for each policy-price scenario. Based on the results of the evaluation and in consultation with the IEs, PacifiCorp will select one or more 2017R RFP wind resource portfolios for further scenario risk analysis. Before establishing a final shortlist, PacifiCorp may take into consideration, in consultation with the IEs, other factors that are not expressly or adequately factored into the evaluation process described above, particularly any factor required by applicable law or Commission order.
Credit Requirements	PacifiCorp will evaluate credit requirements for shortlisted bidders. There is no credit requirements methodology or amount listed in the RFP or contracts.
Transmission	PacifiCorp is seeking resources located in specific areas that can deliver into or in PacifiCorp's network transmission system in Wyoming. Delivery to customer load could occur via a direct interconnection with PacifiCorp's transmission system, or via delivery to PacifiCorp customer load with third-party transmission service. With either delivery method, PacifiCorp prefers bids that will not face

	significant transmission costs or constraints between the resource and PacifiCorp load. While PacifiCorp provides these general guidelines, the available transmission capacity from the project to PacifiCorp's network transmission system in Wyoming is not known until the bidder identifies its proposed point of delivery/point of integration. PacifiCorp will require a completed interconnection system impact study for directly interconnected projects in the bid proposal.
Accounting Issues	All contracts proposed to be entered into as a result of this RFP will be assessed by PacifiCorp for appropriate accounting and tax treatment. Given the term length of the PPA, or the useful life of the asset to be acquired under an asset acquisition or alternative ownership proposal, accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a capital lease or operating lease pursuant to ASC 840, or (ii) the seller or asset owned by the seller, as a result of an applicable contract, be consolidated as a variable interest entity (VIE) onto PacifiCorp's balance sheet. PacifiCorp is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, after bidders are selected for the shortlist, if required by PacifiCorp accounting department, bidders will be required to certify, with supporting information sufficient to enable PacifiCorp to independently verify such certification, that their proposals will not be subject to VIE treatment.
Imputed Debt	PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt as part of the economic analysis in the shortlist evaluation. However, after completing the shortlist and before the final resource selections are made, PacifiCorp may take direct or inferred debt into consideration. In so doing, PacifiCorp may obtain a written advisory opinion from a rating agency to substantiate PacifiCorp's analysis and final decision regarding direct or inferred debt.
Code of Conduct	A Code of Conduct is included in the RFP as Appendix N.
Benchmark Bids	Appendix L of the RFP provides a summary of PacifiCorp's Company Alternatives (Benchmark Resources).
Role of the IE	Appendix M to the RFP describes the role of the IE in the process.
Contracts	The Company provides a sample PPA and Build-Transfer Agreement (BTA).
Schedule	A detailed schedule is provided in the RFP including the following important dates: • RFP Issued to Market – August 25, 2017 • RFP bids due – October 13, 2017 • Initial Shortlist Scoring Completed – November 22, 2017 • Final Shortlist Evaluation Completed – January 8, 2018 • IE review of Final Shortlist Completed – January 15, 2018 • Utah Commission Order in Preapproval Proceeding – March 30, 2018

	• Execute Agreements – April 16, 2018

Changes to the RFP Agreed to by PacifiCorp Since Issuance of the Utah Draft RFP

One of Merrimack Energy's initial concerns after reviewing the draft RFP was that the eligibility requirements, including (1) the requirement that bids had to demonstrate that the project would qualify for the full value of the federal PTC and (2) the requirement that bidders had to deliver their power to PacifiCorp's network transmission system in Wyoming inclusive of the proposed 500 kV Gateway Segment D2 or capable of delivering energy into PacifiCorp's transmission system in Wyoming with the use of third-party firm transmission service would limit the market and result in a less than robust solicitation process. Although PacifiCorp informed the IE that with these requirements they still expected a robust response, the IE was concerned that this may limit the level of competition and therefor effectively favor PacifiCorp's self-build option. In addition, based on recent experience of the IE, in other solicitations involving a linkage between the generation component of the project and the transmission component, project risk and allocation of risk are important considerations. The concern of the IE was that the risk associated with a situation in which the transmission system is delayed beyond December 31, 2020, which results in the generator not able to qualify for the PTC, would affect PPAs and utility-owned options disproportionately. It is also unclear which entity would bear the risk under different scenarios and what would be the impact to customer costs if the transmission project was not built on time to accommodate the generation project and the benefits of the PTC were not realized.

Merrimack Energy staff and members of the Division staff met with PacifiCorp on July 19, 2017 to primarily observe the Code of Conduct training process as well as discuss the evaluation methodology. Prior to the meeting, the IE reviewed the RFP and related documents and raised a number of questions to PacifiCorp as well as providing comments on certain provisions in the RFP. PacifiCorp also retained an IE in Oregon shortly thereafter. Both IEs have made suggestions that PacifiCorp has adopted.

Some of the primary revisions to the RFP proposed by PacifiCorp relative to the initial draft RFP include the following:

1. PacifiCorp revised the schedule slightly to move the Notice of Intent to bid from September 6 to September 15, 2017 after the bidder's workshop on the $12^{th.}$ The IE supports this revision as providing an opportunity for bidders to assess whether to submit a Notice of Intent to bid until after it has had the opportunity to participate in the Bidder's workshop;
2. Revised the initial minimum requirement of requiring a system impact study to only demonstrating that the bidder has initiated the study phase of the interconnection process (i.e. signed agreement and paid deposit to begin feasibility study). Added a condition that the project will require a System Impact Study by the initial shortlist to confirm costs and that it can be interconnected to support 12/31/2020 project commercial operation date. This revision is also supported by the IE;

3. Re-allocated the weights in the non-price table to put higher weighting on the transmission progress. While the IE agrees with this change, the IE has additional comments regarding the non-price criteria;
4. Revised the requirement to meet 100% of the federal PTC to accept full or partial PTC still subject to the December 31, 2020 COD deadline. The IE agrees with eliminating the eligibility requirement that proposals for new wind resources must demonstrate to PacifiCorp's satisfaction that projects will qualify for the full value of the federal PTC;
5. Revised the Code of Conduct to reflect the presence of a self-build option consistent with other PacifiCorp RFPs for which there was a self-build or benchmark option. The IE notified PacifiCorp that the Code of Conduct initially included in the solicitation documents was from the 2016 All Source RFP which did not include a benchmark resource. Since this RFP includes a benchmark resource, the IE suggested that PacifiCorp include a Code of Conduct that reflects the presence of a benchmark resource.

The IE views the changes already made to the RFP documents to be positive steps, although the IE believes more can be done to ensure the process is more equitable and transparent and leads potentially to a more robust and competitive solicitation.

IV. Positions of the Parties

As noted, interested parties were allowed to submit comments by August 4, 2017 on the application for approval of the Solicitation Process for Wind Resources, including the Draft RFP and associated documents. Comments on the draft RFP were filed on the due date by the Division of Public Utilities, Utah Association of Energy Users (UAE), and the Interwest Energy Alliance. A summary of the comments and positions of each party is provided below.

Division of Public Utilities

The Division of Public Utilities ("Division") recommends that the Public Service Commission approve Rocky Mountain Power's ("Company") Application for Approval of the Solicitation Process for Wind Resources conditioned on the Division's recommended changes discussed in its Comments and summarized below. At a high level, the Division believes that the Company's proposed RFP complies with Commission rules and generally is thorough in its scope.

The Division of Public Utilities focused its comments on two areas associated with the draft RFP: These include (1) Minimum size proposal eligible to bid; and (2) Delivery requirements into Wyoming. The positions and recommendations of the Division with regard to each of the above issues are summarized below.

Minimum Proposal Size

The Division noted that the updated Oregon draft RFP requires that facilities of 10 MW and greater may bid, as included in the Oregon guidelines. This is a material change from the Utah draft RFP which indicated that the minimum size is 20 MW. If the Company is required to accept bids from projects as small as 10 MW, it should change the main text to reflect that fact.

The Division recommends the Company clarify whether the minimum size project is 10 MW or 20 MW.

Delivery of Proposals into Wyoming

The Division questions the requirement in the RFP that PacifiCorp will only accept proposals for new wind resources capable of directly interconnecting and delivering energy to PacifiCorp's network transmission system in Wyoming inclusive of the proposed 500 kV Gateway Segment D2 Aeolus to Bridger Anticline substation and transmission system, or capable of delivering energy into PacifiCorp's transmission system in Wyoming with the use of third-party firm transmission service. The Division states that since the Company intends that these resources to be system resources, one of the questions that the Division has had with this process is the requirement that energy from a bidder's project must be delivered to Wyoming which is not close to major load centers outside of Wyoming. The Division further stated that while eastern Wyoming is prime territory for wind resources, it may be possible for a bidder/developer to be competitive with a project location outside of Wyoming. Granted that the chance for the selection of significant amounts of wind generation in this RFP outside of Wyoming may impact the viability of the D2 transmission segment, that situation might enhance ratepayer benefits. The mere fact that something was not selected in a necessarily limited and restricted IRP process does not lead to the conclusion that no other possibilities should be considered in the RFP.

The Division also recommends that the Company relax its demand that the bids necessarily tie into its Wyoming system.

Utah Association of Energy Users

The Utah Association of Energy Users (UAE) submitted initial comments on August 4, 2017. UAE raised a number of concerns about the RFP. According to UAE, the RFP will not attract a broad array of bids sufficient to permit comparison and selection of the most cost-effective options as contemplated by Utah's Energy Resource Procurement Act. Rather the proposed RFP will result in very few complying bids and essentially ensure that PacifiCorp's benchmark resources will be the only available options. UAE submits that the proposed RFP is not consistent with the Act and the RFP cannot properly be approved unless changes are made to maximize the likelihood that bids from a wide array of available resources will be received. Only then is it possible to identify and select resources that are likely to produce the lowest costs and risk for ratepayers as contemplated by the Act. A summary of the key points raised by UAE in its comments is presented below:

Eligibility to Bid

- Only if a robust set of bids for market resources is received can any proposed utility self-build options be fairly compared and evaluated. As proposed, this solicitation process is defective since it will only accept bids of a single resource type (wind) located in a small geographical area of one state. The RFP imposes severe limitations on the type, location and potential owners of resources that can submit qualifying bids, and will severely restrict the universe of possible resource options in a manner inconsistent with the pre-approval requirements of the Act;

- The Commission will be in a position to determine whether any given resource is most likely the most cost-effective resource only if the scope of the solicitation is increased to include all resource types – renewable and non-renewable; west side and east side; all owners/developers; and with and without new transmission upgrades in various locations. The findings required in Parts 2 and 3 of the Act simply cannot be made with PacifiCorp's proposed limitations of the RFP to specific Wyoming wind resources only;

Comparability

- With regard to comparability, UAE notes that it is both a statutory requirement and a critical component of fairness to PacifiCorp ratepayers that benchmarks and bids be evaluated on a fair and comparable basis. The proposed RFP does not satisfy this requirement. If PacifiCorp succeeds in treating its benchmark bids preferentially to other bids, the result will be bias in favor of the benchmark bids;

- Critical to the satisfaction of the public interest standard is comparability to the greatest extent practicable in the evaluation of benchmarks and bids. This standard is emphasized in Commission rules: "all bids must be considered and evaluated against the Benchmark Option on a fair and comparable basis";

- UAE identifies a number of risks imposed on PPA bidders by the PPA agreement that PacifiCorp does not intend to assume for its self-build benchmark option including the following:
    a. PPA bidders are subject to delay damages for each day the project is late past the "Scheduled Commercial Operation Date" (PPA at 17);
    b. PPA bidders are subject to cancellation of the entire PPA if the facility does not achieve commercial operation by the "Guaranteed Commercial Operation Date" (PPA at 17);
    c. If any turbines have not been fully completed when the Facility achieves final completion, there is no option for the PPA seller to cure the shortfall and the turbines cannot later be completed as part of the project, nor can the turbines be completed and the output sold to third parties (PPA at 17):
    d. Under a PPA, PacifiCorp will not pay for any energy curtailed by the transmission operator, whether curtailed for reliability purposes or by the market operator or Transmission Service Provider for general curtailment, reduction, or redispatch of generation in the area, or even if an event of Force Majeure prevents either party from delivering or receiving Net Output (PPA at 24). In contrast, PacifiCorp will undoubtedly expect to recover the costs of its benchmark resources without regard to production levels, curtailments, or events of Force Majeure;

e. PPA rates shall not be subject to change for any reason for the life of the PPA (PPA at 29), while PacifiCorp can ask for rate changes to reflect changes in benchmark resource costs at any time;
f. PPA bidders are subject to liquidated damages for failure to achieve Guaranteed Availability, without regard to actual output of the plant, on top of both foregone energy payments under the PPA plus the cost of replacement energy. These liquidated damages are assessed to the PPA bidder even if the actual energy output of the plant exceeds the expected energy output in that year. PacifiCorp does not intend to pay liquidated damages for its benchmark resources, no matter how poorly the resources perform;
g. PPA bidders face expensive security requirements, project milestones, multiple types of liquidated damages, and other requirements, which PacifiCorp's benchmarks will not face;
h. UAE encourages the Commission to solicit advice from the independent evaluator and other parties and professionals in order to minimize, to the greatest extent possible, biases in favor of utility-owned resources, and to properly recognize the risk-mitigating elements of PPA resources in the solicitation and evaluation process.

Reasons for Rejecting Bids

- Overall, UAE believes that several reasons listed in the draft RFP for rejecting bids are unfair, chilling and inappropriate and should be eliminated or revised including the following:
    - Reason 3 – A new resource that will not qualify for the full PTC. This requirement is unnecessary, as the PTC accrues to the PPA bidder and failure to qualify for the full PTC will not affect firm PPA bids;
    - Reason 9 – Bidder or an affiliate of the bidder is in current litigation with PacifiCorp;
    - Reason 11 – Project not in Wyoming;
    - Reason 12 – Failure to provide completed interconnection system impact study (SIS) in the bid proposal;
    - Reason 14 – Proposal presents unacceptable level of development risk (at PacifiCorp's sole discretion). UAE is concerned with the "sole discretion" implications by PacifiCorp on the bidders.

Timing for the Solicitation

- UAE argues that the speed with which PacifiCorp proposes to issue its RFP and procure wind and transmission resources is a significant concern. The minor economic benefits projected by PacifiCorp are nowhere near sufficiently compelling to warrant making ratepayers take a $4 billion risk on proposed new resources without first confirming that those resources are the most economical resources in comparison to all other potential resource options.

Transmission Cost Implications

- PacifiCorp's proposal to evaluate all bids before considering any costs of the so-called "Gateway sub-segment 4b" means that PacifiCorp's benchmark cost estimates would not include the full cost of interconnection of the benchmark resources, whereas PPA bidders will need to include all projected interconnection costs in making their firm bids. The result would be inappropriate discrimination in favor of benchmark resources.

PacifiCorp's Repowering Proposals

- UAE's view is that although the economics of PacifiCorp's Repowering proposals will be evaluated in Docket 17-035-39, UAE believes a few aspects of the Repowering proposal should be considered in this docket.

Comparability in the Evaluation of Resources

- Given the significant differences in benefits and risks of bids and benchmarks, they cannot be evaluated against each other on a "fair and comparable basis" as required by Utah law unless the significance of these differences is recognized or addressed through assignment of values to the different risks or by taking appropriate steps to reduce these differences. For example, PacifiCorp could be required to submit a "not-to-exceed" benchmark cost estimate that it will be required to live with, like bidders. The independent evaluator and other parties may have other reasonable suggestions for evaluating bids and benchmark resources on a comparable and fair basis. Similarly, PacifiCorp could be required to sell or allow use of PacifiCorp's sites, interconnection rights and safe-harbor equipment by others;

- The 20-year term for the proposed PPAs – compared to a much longer life of comparable PacifiCorp-owned resources – is also a concern, Models used to compare resources of comparable length are imperfect in facilitating apples-to-apples comparisons under such circumstances. Steps should be taken to avoid such incomparability. For example, bidders could be encouraged to offer a fair market value purchase option at the end of the term, which might facilitate a fair comparison. UAE encourages the Commission to solicit input on this (and other) issues from the independent evaluator, parties, and professionals to ensure a fair and reasonable process.

Interwest Energy Alliance (Interwest)

Interwest Energy Alliance's comments address two specific issues:

- Support for the new transmission line and the new wind procurement;

- Interconnection requirements as outlined in the RFP.

Support for Transmission Line and Wind Procurement

Interwest emphasizes that it fully supports the new transmission line and the new wind procurement. These plans will provide substantial savings for Utah ratepayers and all PacifiCorp electricity consumers. Prompt action is required to benefit from the 100% PTC levels which PacifiCorp is seeking to achieve. Therefore, Interwest does not support delay of these proceedings. However, it is important that the most efficient projects be acquired which will provide to customers the most savings and other benefits renewable energy can provide. To achieve this result Interwest recommends that the Commission require a fair, open and transparent, fully competitive RFP and bid review process.

Interconnection Requirements

Interwest believes that a requirement that a system impact study be submitted along with the bid is not reasonable, is anti-competitive, and should be extended as described herein. There is no commercial or regulatory basis for this requirement for early completion of a system impact study by mid-October when bids are due. Interwest argues that the RFP requires a wind project which can be interconnected to a transmission line which does not yet exist. Furthermore, the transmission line and associated new wind procurement is not yet part of an approved IRP.

Interwest recommends replacing the deadline with a requirement that the bidder provide proof that all interconnection requirements may be completed prior to commercial operations, with completion of a system impact study to later than January of 2018, a date which does not delay this proceeding. The Commission could reasonably expect an interconnection request to be submitted by a bidder by August 1, 2017 (less than 4 months after this Application with the proposed RFP was filed with the Commission on April 17, 2017). Interwest recommends that the system impact study deadline be revised to January 5, 2018. If a bidder submits the interconnection request with the required funding by August 1, 2017 and waives the feasibility study, a system impact study could be completed, allowing the transmission operator sufficient time to process the request under the OATT guidelines. Interwest concludes that there is significant time in the schedule for the utility to process projects that have submitted an interconnection request by August 1, 2017 and for the utility to complete the interconnection studies in the time frame required by the relevant Open Access Transmission Tariff. Interwest recommends that the Commission eliminate the fundamentally unfair early deadline for completion of a system impact study. Specifically, Interwest recommends that this term be amended to leave the system impact study requirement open, instead requiring a bidder to provide evidence that the system impact study will be completed so that all interconnection requirements and upgrades could be completed prior to final interconnection to accommodate commercial operation by December 31, 2020.

V. Discussion of Important Competitive Bidding Issues

This section begins with a listing of the factors that are important for an effective competitive bidding process in any state and under any circumstance based on Merrimack Energy's experience and consistent with Utah statutes and Commission directives. Following these factors, this section continues with a more detailed assessment and discussion of the important competitive bidding issues associated with the 2017R Draft RFP. The IE has identified several issues that arose in review of the Draft RFP and related documents and discussions with PacifiCorp that warrant review and discussions as having an impact on the success of the competitive procurement process. The issues identified are common considerations in most power procurement solicitation processes. These issues will be presented and discussed from several perspectives including fairness principles, transparency of the process, consistency with Utah statutes, and consistency with industry standards.

In addition to Merrimack Energy's review of the RFP documents, Merrimack Energy staff and representatives from the DPU participated in a meeting with the PacifiCorp team to discuss the RFP process, notably focusing the discussion on the bid evaluation methodology and process as well as the models to be used and input assumptions. Merrimack Energy also prepared a list of over forty questions for PacifiCorp based on review of the Draft RFP and related documents. Merrimack Energy also made suggestions regarding aspects of the Draft RFP, many of which were agreed to by PacifiCorp. For completeness purposes, Merrimack Energy will identify these considerations and the outcome.

Based on the comments of the participants in the proceeding as well as Merrimack Energy's view of the key Draft RFP issues based on review of the 2017R Draft RFP and associated documents, the following issues are addressed: (1) Comparability of third-party bids and utility-owned resources; (2) RFP Schedule; (3) Bid Blinding; (4) Bid Eligibility; (5) Allowable Contract Term for PPA; (6) Non-Price Criteria; (7) Credit Requirements; (8) Allowable Alternatives/Bid Fees; (9) Transmission Issues/ Requirements; (10) Accounting; (11) Webpage; (12) Bid Evaluation Process and Methodology; (13) Models and Input Assumptions. In addition, Merrimack Energy has also provided a red-line of the RFP document with specific comments on the provisions of the RFP as Appendix A.

A. Characteristics of any Effective Competitive Bidding Process

In assessing whether a competitive procurement process is likely to lead to a positive outcome which benefits customers, meets the objectives and criteria established, and is consistent with regulations and statutes, Merrimack Energy considers the following issues and characteristics of the process:

1. The solicitation process should be fair and equitable, transparent, consistent, comprehensive and unbiased to all bidders. Fairness and transparency in the process means that all bidders are treated the same and have access to the same information at the same time. Also, for assessing the documents and information at this stage of the process, one of the key criteria is bias,[3] whether intended or unintended. Merrimack Energy's evaluation at this stage is designed to identify if any bias exists with regard to the type of

[3] Bias can take several forms such as design of a competitive procurement process in which bidders feel that the process unduly favors one type of resource over another. Bias can also come into play with regard to the application of the quantitative and qualitative evaluation processes such as quantitative methodologies that favor projects of different terms, sizes or in-service dates or different transaction types.

products, resources, bid categories and alternatives, etc. that are allowed to compete in the process and the methods for evaluating and scoring the competing products.

2. Scoring and evaluation of proposals can be free of intended and unintended bias only if similarities in proposals are evaluated and scored similarly and differences in proposals are evaluated and scored differently. In identifying similarities and differences, all costs, benefits and risks of competing proposals must be accurately identified and fairly assessed.

3. The solicitation process should ensure that competitive benefits for utility customers result from the process. In this regard, it is important to determine whether all costs to consumers are reflected in the evaluation process so that true competitive benefits emerge in both the intra-resource and inter-resource comparisons.

4. The solicitation process should be designed to encourage broad participation from potential bidders. In this regard, it is important to assess whether the process is sufficiently transparent to allow bidders to determine how they can best compete in the process and sufficiently balanced so that no potential bidder faces uneven burdens or enjoys uneven advantages.

5. The Request for Proposal documents (i.e. RFP, Information required from bidders, and Model Contracts) should describe the bidding guidelines, the bidding requirements to guide bidders in preparing and submitting their proposals, the bid evaluation and selection criteria, and the risk factors important to the utility issuing the RFP. The RFP documents should effectively inform bidders how they can compete in the process. A robust response to a solicitation process is generally an indication that bidders feel the process is fair and they have a reasonable opportunity to effectively compete.

6. The solicitation process should include thorough, consistent, and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process.

7. Another consideration in assessing the integrity of the solicitation process is to assess whether the risk allocation associated with contracts for different types of resources or products is reasonable. Ideally, all contract types and resource types would include provisions/conditions that allow for the same or very similar risk allocation to allow for a completely level playing field. However, in practice this is not inherently practical since different transaction types and resource types have different characteristics. Placing all of the options considered on a level playing field in terms of risk allocation and in evaluating bids is a real challenge. The solicitation process should ensure that the resource contracts are designed to provide a reasonable balance between the objectives of the counter-parties, seeking to minimize risk to utility customers and shareholders while ensuring that projects can reasonably be financed. Differences in the project contracts should be fairly reflected in the evaluation and selection process.

8. The solicitation process should incorporate the unique aspects of the utility system and the preferences and requirements of the utility and its customers.

9. The solicitation process should be developed and undertaken consistent with State law and statutes governing competitive procurement processes.

The application of a fair and transparent competitive procurement process is important for creating competition for the overall benefit of customers. Fairness generally means that all bidders are treated similarly, have access to the same information at the same time, and have equal opportunity of being successful in the process. A reasonable level of transparency[4] is also another important element leading to a successful solicitation process. Transparency means that there is a reasonable amount of information to guide bidders in preparing a complete proposal to meet utility requirements. Reasonably transparent processes are those that provide information, guidance, and direction to bidders on the information required by the utility to evaluate their proposals, provide guidance on the bid evaluation criteria, bid evaluation and selection process. Fair and reasonably transparent processes should encourage competition among potential bidders who can adequately determine if they have the ability to effectively compete in the process and lead to more complete and comprehensive proposals. The greater the level of competition for all products sought by the utility the greater the chance for competitive options and lower prices for consumers.

<u>B. Utah Specific Competitive Factors</u>

The Energy Resource Procurement Act, codified at Utah Code §§ 54-17-101 et seq. (the "Act"), as applied to the facts of this RFP, controls this assessment by the IE. The Act creates a public interest standard for Commission review and approval of this Draft RFP in UCA § 54-17-201(2)(c)(ii) as follows:

> In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:
> *   *   *
> (ii) is in the public interest taking into consideration:
> (A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;
> (B) long-term and short-term impacts;
> (C) risk;
> (D) reliability;
> (E) financial impacts on the affected electrical utility; and
> (F) other factors determined by the commission to be relevant.

[4] Merrimack Energy always uses the term "a reasonable level of transparency" because a competitive procurement process is very rarely fully transparent. Bidders, for example, don't have access to the utility's models and data used to evaluate other proposals. Likewise, the utility generally doesn't provide the detailed back-up information for all the criteria used to evaluate bids from a quantitative perspective.

While the Act controls these proceedings, the context of this assessment is a Soliciting Utility which is subject to both a duty to serve and a duty of prudence in meeting its duty to serve. With respect to Commission rate-making, for example, see: UCA § 54-4-4(4)(a) (added by Senate Bill 26, 2005). Prudently implementing its duty to serve will require PacifiCorp to observe the Act, much as it observes all applicable permitting, licensing, rate-making and other laws. However, the duty to serve creates no preference for utility-owned resource options. To the contrary, the duty to serve requires a truly workable procurement process - - in compliance with the Act.

C. Comments on the PacifiCorp 2017R Draft RFP

Below is a compendium of our comments on PacifiCorp's 2017R RFP. The comments reflect the positions of the interested parties who submitted comments, our own assessment based on a review of the 2017R Draft RFP, requirements of Utah Code and Regulations and industry practices associated with similar solicitations.

1. Comparability[5]

In order for the RFP process to satisfy the criteria for an effective and efficient competitive bidding process and produce a result that is in the public interest, all resource options should, to the greatest extent possible, be made directly comparable and put on an even footing or "level playing field" for evaluation and selection purposes, such that no single bidder or resource option has an unfair advantage over another bidder or resource option. In competitive procurement processes where a utility self-build option or utility ownership option is allowed to compete, comparability is a very important consideration in the RFP design and evaluation process. The major consideration is that a utility-self build or ownership option is generally developed on a cost of service basis.[6] This means that the utility cost is not fixed at the time of submission. One of the concerns of other competitors is that the utility could submit a low-cost proposal or offer to be selected and then propose higher costs before the Commission based on the additional costs being prudently incurred based on market conditions. Although the Commission would have final say on whether the costs were prudently incurred or could require the utility to reduce its cost of service if actual costs are lower than originally estimated, other bidders, such as PPA providers argue that its costs are fixed at the time of offer submission and it therefore takes all the risk associated with any cost increases. On the other hand, PPA providers also receive any of the benefits of project cost decreases given the fixed price nature of their offers.

UAE, in its comments, states that critical to the satisfaction of the public interest standard is comparability to the greatest extent practical in the evaluation of the benchmarks and bids. This standard is emphasized in Commission Rules: "All bids must be considered and evaluated against the Benchmark option on a fair and comparable basis." It is both a statutory requirement and a critical component of fairness to PacifiCorp ratepayers that benchmarks and bids be

[5] Comparability refers to the evaluation of power generating resources with different project structures and characteristics on a fair and consistent basis. For example, resources that will be owned by the utility will have a very different cost and risk structure that a Power Purchase Agreement (PPA) where the bidder submits essentially a firm price and must absorb the risks and benefits of changes in costs for the project relative to its contract pricing.
[6] This is also referenced as a "cost-plus" basis.

evaluated on a fair and comparable basis. UAE concludes that the proposed RFP does not satisfy this requirement. In support of its position UAE identifies a number of examples of risks imposed on PPA bidders that PacifiCorp does not intend to assume for its self-build option, including identifying a number of PPA contract provisions that shift significant risk to PPA bidders.

UAE also raises comparability issues as they pertain to the evaluation of proposals. Given the significant differences in benefits and risks of bids and benchmarks, they cannot be evaluated against each other on a "fair and comparable basis" as required by Utah law unless the significance of these differences is recognized or addressed through assignment of values to the different risks or by taking appropriate steps to reduce these differences. The independent evaluator and other parties may have other reasonable suggestions for evaluating bids and benchmark resources on a comparable and fair basis. The 20-year term for the proposed PPAs – compared to a much longer life of comparable PacifiCorp-owned resources – is also a concern, Models used to compare resources of comparable length are imperfect in facilitating apples-to-apples comparisons under such circumstances. Steps should be taken to avoid such incomparability. For example, bidders could be encouraged to offer a fair market value purchase option at the end of the term, which might facilitate a fair comparison. UAE encourages the Commission to solicit input on this (and other) issues from the independent evaluator, parties, and professionals to ensure a fair and reasonable process.

Merrimack Energy recognizes the valid concerns about comparability raised by UAE and addressed by Merrimack Energy in similar IE reports on PacifiCorp's draft RFPs prepared by Merrimack Energy on previous PacifiCorp solicitations. In previous IE reports on the draft RFP, Merrimack Energy provided a detailed assessment of different procurement models and options for achieving comparability. As we noted in our report on the 2008 All Source RFP, we view the comparability issue to be the most important and most complex issue in the design of competitive bidding processes. Unfortunately, there are no industry standards or valid working models that can be relied upon to ensure comparability in resource treatment. Merrimack Energy will not repeat the discussion here with regard to comparability of resource options, but instead suggests that the April 11, 2008 Report of the Independent Evaluator Regarding PacifiCorp's All Source Request for Proposals be available as a reference in this regard.[7]

Merrimack Energy assesses the comparability issues from a number of perspectives:

- Equitable access to information (i.e. the utility-ownership option has access to information that other bidders may not have).[8] In most cases, this issue is addressed through the safeguards that are put in place by the utility to ensure the self-build option does not have undue access to information. Examples of safeguards included in PacifiCorp's 2017R solicitation process are:

[7] Report of the Utah Independent Evaluator Regarding PacifiCorp's All Source Request for Proposals, April 11, 2008, Docket No. 07-035-94.

[8] The safeguards generally pertain to information developed during the solicitation process. It does not address access to information that members of the various teams would have prior to the initiation of the solicitation process that may provide a competitive advantage.

- PacifiCorp has identified a separate team for conducting the evaluation process and a separate team to prepare the benchmark bids;
- All team members are subject to a specific Code of Conduct Governing PacifiCorp's Intra-Company Relationships for RFP Process. Team members were subject to Code of Conduct training. PacifiCorp has committed to provide the names of all team members to the IE;
- The Benchmark bids will be reviewed and validated by the IE and analyzed for reasonableness and consistency with the solicitation process. The Benchmark bids will be reviewed, evaluated and scored by the IEs and PacifiCorp and locked-down 7 days prior to receipt of the RFP bids;
- Merrimack Energy will set up a webpage on its website to coordinate all questions and answers from the bidders and will blind bidder names prior to sending the questions to PacifiCorp;
- All Bidders will have access to the same information at the same time. All bid related information will be posted on both the Merrimack website and the PacifiCorp website for the RFP;
- PacifiCorp's Benchmark options will be required to provide the same information as other bidders.

- Consistent evaluation terms for all resources, using the same set of input assumptions. Consistent with R746-420-3(8)(k), the solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark option. One of the primary issues in this regard occurs when PPA bids are limited to a 20-year term (as PacifiCorp proposes) while the evaluation time horizon occurs over the 30-year life of the utility asset. The methodology used to "fill in" or account for the final 10 years of the time horizon after the PPA term is complete is a primary issue in most evaluation processes. One approach to address this is to allow a PPA bidder to offer a 30-year contract as well or in lieu of a 30-year contract, a 20-year contract with a bidder-proposed 10-year extension that is exercisable by the utility;

- Ensuring that all costs associated with the self-build are appropriately accounted for and included in the evaluation. This requires the oversight and scrutiny on the part of the IE to ensure all costs are included including such costs as capital expenditures during the life of the asset, owner's costs such as administration costs, insurance and property taxes, AFUDC, O&M costs, etc. The IE will be focused on reviewing all cost information associated with the Benchmark option and analyze the reasonableness of the costs. PacifiCorp has included some of these costs in its Input Assumption files provided to the IEs;

- Request the self-build team to submit its cost estimate under a range of cost contingency levels. For example, from an engineering cost perspective, project costs may be based on a P50 confidence level. Under this case, the utility will prepare a fairly high-level cost assessment but would be 50% confident the cost would not exceed the estimate. An alternative cost estimate would be to develop a P70 confidence level for estimating the project cost. This would lead to a higher level of contingency. Both cost levels could be evaluated to assess the impacts on the cost of the self-build versus third-party options.

2. RFP Schedule

PacifiCorp proposed an expedited schedule for undertaking this solicitation based on the time-limited nature of the opportunity relative to the need to achieve commercial operation by the end of 2020 to qualify for the full value of the Production Tax Credit (PTC) for wind and the coordination required to approve and construct the transmission facilities. The schedule for this solicitation from the date of issuance of the RFP to regulatory approvals is expected to take only seven months. The schedule is compressed relative to previous PacifiCorp solicitation, but the process can be completed on time. Merrimack Energy had a suggestion for revising one date which should not affect the overall schedule. The initial schedule required that the Notice of Intent to Bid would be due on September 6, 2017, slightly over a week after the RFP is issued to the market. The Bidder's conference is scheduled for September 12, 2017. In addition, it was a requirement that bidders submit an Intent to Bid Form and Bidder Credit Information (Appendices B and D) on September 6, 2017. The IE felt that bidders will have to make a determination to compete shortly after the final RFP is issued. To allow bidders adequate time to assess the requirements in the final RFP and decide whether they want to compete in the process, Merrimack Energy suggested to PacifiCorp to move the date for submission of the Intent to Bid Forms until after the Bidders Conference on September 12, 2017. We proposed that the Intent to Bid Forms should be due on September 15, 2017. This proposed change in schedule should not affect the overall schedule for submission and evaluation of bids. PacifiCorp agreed with the suggestion and revised the final schedule to reflect this proposed change.

3. Bid Blinding

The Commission's RFP rules require that the IE receive and "blind" bid responses.[9] PacifiCorp requested a waiver of this requirement consistent with prior waivers provided by the Commission in other prior solicitations. PacifiCorp noted that both the IE and Division of Public Utilities questioned the value of blinding bids in previous solicitations. PacifiCorp further noted that "while the blinding of names of bidders was valuable during the question and answer period, the specific blinding of bids did not have commensurate value given the level of effort. Here blinding bids will provide limited value because the detailed project information included in each bid (e.g. the proposed location of the resource) will effectively identify the bidder. Blinding bids imposes additional burdens on the IE and the Company that will have no impact on the overall fairness of the solicitation process."

The IE's experience with other solicitation processes that have used bid blinding to avoid any evaluation and communication bias is that there is no certainty that the bidder could remain anonymous. Furthermore, blinding bids could be time consuming and costly with limited value. Also, given the eligibility requirements associated with this solicitation, it can be expected that a number of the projects bid would be located in Wyoming, for which PacifiCorp would have knowledge either through the interconnection queue process or based on PacifiCorp's direct involvement in the market.

[9] See Utah Admin. Code R746-420-3(10)(a) and R746-420-6(2)(f).

The IE does suggest that blinding the Q&As remain a part of this process. Also, if the Commission decides that some form of blinding is required, one option may be to restrict the availability of pricing data only to the evaluation team members who will conduct the quantitative evaluation. Merrimack Energy has found that perhaps the primary bias associated with the access to proposal information is for the qualitative evaluation team members, who are largely involved in a subjective evaluation process knowing who the best proposals are from a pricing perspective and allow this information to somehow bias their evaluation of the qualitative criteria.

As we previously discussed, there are a number of safeguards built into the solicitation process to mitigate concerns over self-dealing or bias on the part of the PacifiCorp teams to favor the self-build option. We do not believe "blinding" of bids will add value commensurate with the cost and time to effectively blind the bids as required.

4. Bid Eligibility

Eligibility to bid in this RFP was initially focused on the following factors:

- Proposals for new wind resources must demonstrate, to PacifiCorp's satisfaction, that projects will qualify for the full value of the federal PTC;
- PacifiCorp will accept proposals for new wind resources capable of directly interconnecting and delivering energy to PacifiCorp's network transmission system in Wyoming inclusive of the proposed 500-kV Gateway Segment D2 Aeolus to Bridget Anticline substation and transmission system in Wyoming with the use of third-party firm transmission service;
- PacifiCorp will only consider projects that demonstrate a unique value opportunity for its customers and achieve commercial operation by December 31, 2020, without compromising system reliability;
- PPA term is limited to 20 years;
- In the initial draft of the RFP, PacifiCorp required bidders to provide a system impact study as defined in the transmission provider's OATT as part of its bid proposal. PacifiCorp has revised this requirement to be more reasonable for bidders;

One of the bidder eligibility requirements listed by PacifiCorp in its Draft RFP is that proposals for new wind resources must demonstrate, to PacifiCorp's satisfaction that projects will qualify for the full value of the federal PTC, if applicable. In response to a question from the IE, PacifiCorp stated that this means resources must demonstrate that they can qualify for 100% of the PTC, currently set at $24/MWh, and are not subject to discounted PTCs as established in the PATH ACT extension, which provides for a phase-out of the PTC. The IE does not understand why bidder eligibility should be limited to this requirement. While it is likely that projects, such as PacifiCorp's self-build option, who qualify for the full value of the PTC, will be in a favorable competitive position, there may be other projects that also have competitive advantages and at least should have the opportunity to decide if they want to compete given the transparent information provided in the draft RFP about PacifiCorp's preferences. PacifiCorp has agreed to remove the eligibility requirement that proposal must qualify for the full value of the federal PTC.

While the IE does not have an intimate knowledge of the wind energy market in Wyoming and proximity, the IE questions why only **new** wind resources are allowed to compete, as required. Perhaps there may be other projects in the market who have contracts which are terminating and may prefer to repower or expand their projects. Allowing the opportunity for other competitors can only enhance the opportunity to reduce costs for consumers. The IE therefore recommends that the eligibility requirement for only new wind resources be removed and allow repowering projects to compete as long as those projects are not under contract at the time of bid submission.

The Division of Public Utilities questions the requirement in the RFP that PacifiCorp will only accept proposals for new wind resources capable of directly interconnecting and delivering energy to PacifiCorp’s network transmission system in Wyoming inclusive of the proposed 500 kV Gateway Segment D2 Aeolus to Bridger Anticline substation and transmission system, or capable of delivering energy into PacifiCorp’s transmission system in Wyoming with the use of third-party firm transmission service. The IE agrees with this position. It would appear to the IE that the only reasonable way to determine if the combination of wind generation in Wyoming in combination with the construction of the D2 Segment is a least cost solution that provides benefits to customers is to market test this option. Only by allowing the possibility for competitive options to compete would this be possible.

The IE was also concerned with the requirement in the Draft RFP that PacifiCorp would require a completed interconnection system impact study for directly interconnected projects in the bid proposal. The IEs concern was that only projects who had filed interconnection applications and were moving through the interconnection process would be eligible to compete. This would likely limit competition. PacifiCorp has revised its latest draft of the RFP to remove this requirement and instead require that bidders demonstrate they have filed an interconnection application at the time of bid submission with the system impact study submitted if the proposal is selected for the shortlist.

The IE does not have a specific recommendation regarding the eligibility for the type of resources allowed to bid beyond wind. The IE notes that it is common practice in resource procurement processes to undertake targeted solicitations if warranted by market conditions.

5. Allowable Contract Term for PPA

The draft RFP (page 2) limits the term of a PPA to 20 years. PPA bidders can include an option for PacifiCorp to purchase the project during or at the end of the contract term. At the same time, the benchmark options are expected to be evaluated over a 30-year term. The unequal terms associated with a PPA versus utility ownership raises a number of equity considerations in the evaluation process. For this analysis, PacifiCorp intends to calculate the change in total system costs (energy and capacity) with proxy wind resources and new transmission at zero cost and one without proxy wind resources and new transmission. In any case, the comparison of a 20-year option versus a 30-year option is subject to market forecasts and assumptions over the thirty-year time horizon of the benchmark.

Section R746-420-3(8)(k) states that the "Solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark Option. The Commission may waive this requirement during review of the draft Solicitation and Solicitation process for good cause.

The IE believes there are two reasonable options to address this issue. One option would be to allow PPA bidders to offer a 30-year contract term if they chose. PacifiCorp could require a 20-year proposal but also allow bidders to offer 30-years as an alternative. A second option would be to allow the bidder to include in its proposal a contract extension option at the buyer's discretion. Under this approach, the seller could essentially offer a 30-year PPA comprised of a firm 20-year PPA and a 10-year extension option that would be triggered by the buyer at some specified time prior to the expiration of the 20-year PPA term. Bidders would have to commit to the pricing of the contract during the option period. If such an option is allowed and a bidder offers such an option, it will require a bidder interested in this option to assess the accounting implications of a 30-year commitment to sell the power from the project to the utility.

6. Non-Price Criteria

Merrimack Energy has several issues associated with the Non-price factors included in Section 6 of the Draft RFP. Factors included under Conformity to RFP Requirements, such as (1) Bids provided all required RFP information pursuant to RFP instructions and schedule and (2) Bids in compliance with technical specifications are generally considered eligibility or threshold requirements rather than non-price factors. We would expect that if a bidder didn't provide all required information or provided inaccurate information it would be given the opportunity to cure and if the bidder doesn't cure the proposal would likely be considered non-conforming. There are a number of other non-price factors that could be considered in developing the non-price criteria such as Experience of the Bidder, access to generating equipment, Operations and Maintenance plan, Financing Plan for the project, etc. While PacifiCorp has made some changes to this Table and increased the weighting for the Transmission Interconnection factors, the IE suggest that PacifiCorp consider revising the non-price factors listed in Section 1 of the Table in Section 6 of the Draft RFP.

7. Credit Requirements

Unlike in previous RFPs, the Credit Requirements information currently included in the RFP provides little guidance to bidders as they prepare their proposals. There is little discussion of the credit evaluation methodology and the amount of credit assurance required for both PPA options and Build Transfer options is currently blank. The IE suggests that PacifiCorp provide some guidance to bidders regarding the amount of credit assurance required so that bidders can include the cost implications in their proposals at this time or inform bidders that this information will only be provided to shortlisted bidders who can include the cost of credit in their best and final offer.

8. Allowable Alternatives/Bid Fees

Each bidder shall pay a fee (Bid fee) of $10,000 for each base proposal and one alternative submitted. Bidders will also be allowed to offer up to three additional alternatives at a fee of $3,000 each. In addition, PacifiCorp also encourages PPA bidders to include an option to purchase the project during or at the end of the contract term to retain the value of the site for customers. Presumably, this option would qualify as the one alternative available for the bid fee. Since PacifiCorp is encouraging this option, we would recommend that an additional alternative be added at no additional cost for the bidders. Therefore, we recommend that for the bid fee of $10,000, the bidders are allowed to offer a base bid and up to two alternatives, instead of one alternative.

9. Transmission Issues/Requirements

PacifiCorp has made several important adjustments to the transmission interconnection requirements to provide for a more competitive process. However, as the IE has noted, the complexities associated with the development of the transmission facilities for the D2 system, timing for securing interconnection studies, and other transmission-related considerations are significant and may be a challenge to bidders given the tight schedule. In previous solicitations, Merrimack Energy requested that PacifiCorp either hold a transmission workshop or dedicate a significant portion of the Bidders Conference presentation to transmission-related issues. The IE suggest that PacifiCorp consider a similar approach for this RFP and include a significant amount of information on the transmission issues and requirements in its Bidders Conference presentation.

10. Accounting

Accounting issues can be complex based on recent changes in the lease accounting rules. In its write in this section of the Draft RFP (Section 5.I), PacifiCorp states “Bids that result in VIE treatment will be rejected after they are given an opportunity to provide an alternative structure that does not trigger a VIE.” We added the following sentence to end of the second paragraph (see Merrimack Energy’s comments on the Draft RFP document attached) – “To the extent that PacifiCorp rejects a proposal submitted in this RFP because it triggers capital lease or VIE treatment, PacifiCorp shall provide documentation to the IEs justifying the basis for the decision.”

11. Webpage

Task B3 of the IE Scope of Work as listed in the Commission’s RFP for Independent Evaluator requires the IE to set up and maintain a webpage or database for information exchange between bidders/potential bidders and PacifiCorp **only if directed by the PSC in its Approval of the Solicitation Process.** Merrimack Energy proposed to establish a webpage on its website to accommodate this requirement similar to the webpages we established for previous PacifiCorp RFPs. The webpage will be used to accept questions from bidders, which Merrimack Energy staff will blind by removing the name of the bidder, before sending the questions to PacifiCorp for a response. Merrimack Energy will then review the responses and post the Question and

Answer to the webpage for bidders to review. Merrimack Energy will also post any RFP documents on the webpage as well as posting any Notices to bidders of upcoming schedule items or changes to RFP documents.

12. Bid Evaluation Process and Methodology

Section 6 of the Draft 2017R RFP describes PacifiCorp's proposed bid evaluation and selection process and evaluation methodology. In addition, Merrimack Energy Staff and DPU staff attended a meeting with members of PacifiCorp's team to review and discuss PacifiCorp's bid evaluation and selection methodology, models and assumptions.

As described in the RFP, PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new wind projects bid into the 2017R RFP that will maximize customer benefits when paired with the proposed Aeolus to Bridger/Anticline transmission line. PacifiCorp indicates that the method used to evaluate and select bids is consistent with the methods that were used to evaluate new wind resources and transmission infrastructure in PacifiCorp's 2017 IRP. The same method will be used to evaluate benchmark resources and market bids.

PacifiCorp proposes a two-phase evaluation process. In the first phase, PacifiCorp will establish an initial shortlist based on a combination of price and non-price factors. Price will be weighted at 80% and non-price at 20%. In this phase, PacifiCorp will primarily rely on its Screening model, an Excel based spreadsheet model. This model (formerly called the RFP Base Model in other RFPs) has been refined for this assessment. The model is designed to calculate the delivered revenue requirements cost of each benchmark or bid price for each market bid netted against the energy, capacity, and terminal value benefits of each bid to calculate the net cost of each benchmark resource and market bid.[10] In addition to the spreadsheet model, PacifiCorp will utilize the System Optimizer Model (SO Model) and the Planning and Risk model (PaR) to develop the energy and capacity benefits associated with each bid.[11] The net cost calculation (in $/MWh) will be used to assign a price score to each benchmark resource and each market bid. This will be achieved by calculating the nominal levelized (discounted) revenue requirement cost and the nominal levelized (discounted) benefit for each benchmark resource and market bid, where revenue requirement costs are reported as a negative value and customer benefits are reported as a positive value.

The pricing score of each bid and benchmark is combined with the non-price results for each bid and benchmark. Based on the rankings, PacifiCorp will select an initial shortlist based on total

[10] Essentially, the model is designed to calculate system benefits minus system costs. Benefits include the energy and capacity value associated with each bid plus PTC value if applicable plus Terminal value, if applicable. Cost components include cost of energy, capacity, integration cost, and other costs as may be applicable for benchmark resources. For PPA bids, the cost side of the equation will primarily be comprised of the energy cost included in the bidder's proposal.

[11] Energy and capacity benefits will be based on two production cost model runs – one with proxy wind resources and new transmission at a zero cost and one without proxy wind resources and new transmission. The differential in system fixed and variable costs between the two production cost model simulations will serve as the basis for expected energy and capacity benefits.

score. PacifiCorp indicated that bidders with the highest point summed totals, and representing 2,000 MW of aggregate capacity bid, will be considered for the initial shortlist.

Bids selected for the shortlist will be given an opportunity to provide best and final pricing. Best and final pricing shall not exceed 10% of the original total bid cost, which PacifiCorp will assess on a present value revenue requirements basis.[12]

In the Phase 2 Final Shortlist phase, PacifiCorp will use the same proprietary models used for the initial shortlist price evaluation, with bids updated for best and final pricing and projected performance, to process bid costs for input into IRP production cost models.

PacifiCorp will use the System Optimizer model – the same model used by PacifiCorp to develop resource portfolios in the 2017 IRP – to develop a resource portfolio containing 2017R RFP bids with the Aeolus to Bridger/Anticline transmission project. For purposes of the 2017R RFP, the SO model will be used to select the combination of wind projects from the initial shortlist, up to approximately 1,270 MW, that minimizes system costs among a range of different environmental policy and market price scenarios. For each of these portfolios, the SO model will be configured to include the cost and incremental transfer capability associated with the Aeolus to Bridger/Anticline transmission project. The SO model will also be used to establish least cost resource portfolios for each policy-price scenario without any new wind and without the Aeolus to Bridger/Anticline transmission project. For each policy-price scenario, PacifiCorp will calculate the present value revenue requirement differential (PVRR(d)) between the portfolio containing 2017R RFP wind resources with the Aeolus to Bridger/Anticline project, inclusive of the transmission project costs, and the portfolio without 2017R RFP wind resources and without the Aeolus to Bridger/Anticline transmission project.

PacifiCorp will also evaluate each of the resource portfolios developed with the SO model using Planning and Risk (PaR) – the same model used in PacifiCorp's 2017 IRP to analyze stochastic resource portfolio risk. For purposes of the 2017R RFP, PaR will be used to calculate the stochastic mean PVRR(d) and the risk-adjusted PVRR(d) for each policy-price scenario. PacifiCorp will summarize and evaluate the 2017R RFP wind resource portfolios to identify the specific benchmark resources and market bids that are most consistently selected among the policy-price scenarios and that deliver economic benefits for customers. Based on these data, and in consultation with the IEs, PacifiCorp will select one or more 2017R RFP wind resource portfolios for further scenario risk analysis.

PacifiCorp will then summarize and evaluate the results of its scenario risk analysis, considering PVRR(d) results and annual customer impacts, to identify the specific benchmark resources and market bid resources that maximize customer benefits. Based on these data and certain other factors as described in the RFP, and in consultation with the IEs, PacifiCorp will establish a final shortlist to be submitted for approval or acknowledgement. Once the final shortlist is established and bidders notified, PacifiCorp will initiate negotiations with final shortlisted bidders.

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[12] In a previous PacifiCorp RFP the methodology used to calculate the 10% limit for bid cost was not clearly defined. The IEs recommended clarifying the basis for calculating the 10% limit. PacifiCorp has provided clarity in this RFP by stating that the 10% limit will be based on present value revenue requirement.

Merrimack Energy has served as IE on several PacifiCorp RFP processes where the same or substantially similar evaluation process using the same models and methodologies have been used. The IE believes that this methodology is a reasonable and comprehensive evaluation methodology providing significant information on which to assess the final results and selection process. The IE still has some questions regarding the methodology that will be used to assess terminal value in the evaluation process as well as the revenue requirements accounting treatment for the PTC benefits calculations but will address those issues prior to or during the evaluation process.

13. Models and Input Assumptions

Based on Utah Administrative Code R746-420-1(2), PacifiCorp was required to provide to the IE data, information, and models necessary for the IE to analyze and verify the models at the time of filing, or earlier if practicable. Scheduling Order in Docket NO. 17-035-23 required that PacifiCorp provide the information to the IE by Friday, July 28, 2017. PacifiCorp provided the IE the latest version of its spreadsheet model (formerly called the RFP Base Model) as well as the latest input assumptions for the evaluation by July 28, 2017 as required, although such assumptions would be subject to revision. The IE was able to download, review and verify that the model should provide consistent and reviewable results and is consistent with PacifiCorp's description of the model outputs to be used in the review and evaluation of bids and benchmarks for purposes of selecting a shortlist.

VI. Assessment of the Contract and Related Benchmark Risk Issues

Introduction

Merrimack Energy has undertaken a thorough review of the contracts provided for several reasons. First, from a comparability of resources perspective, the risk allocation provisions in the contracts can have a material impact on the fairness and comparability of the process since the bidders will generally price in the risk factors in their proposals. Undue risk associated with contract provisions across contracts can bias the results of the evaluation process. Second, based on the IE's involvement in other solicitations where generation and transmission resources are linked or coordinated, the risks associated with one component of the project (i.e. transmission facility construction) either preceding or following construction of the other component (i.e. generation) can have implications on cost causation and cost recovery. This is particularly important in this case where the benefits associated with securing PTC value can have significant cost implications on customers if the transmission facilities are not constructed on time to allow the generation project sponsor to get the full benefits of the PTC on behalf of the utility customers. The impact of this risk on third-party generators versus utility-ownership options could be very significant.

The pro forma contracts in the 2017 Wind Draft RFP present a fundamental difference in approach between (i) an energy and capability "product" which is based upon first developing a capital asset and then delivering from that asset its net electrical output and capability rights under a performance-based long term agreement (the Purchased Power Agreement or PPA); and

(ii) a capital asset "product" which entails the development and construction of the asset which is then transferred for the use of the new title holder (the Build Transfer Agreement or BTA). In prior contract structures with somewhat different formats, the capital asset product arose out of pro forma agreements styled as Engineering, Procurement and Construction Agreements (EPCs); Master Development Engineering, Procurement and Construction Agreements (MDEPCs) and Asset Purchase and Sale Agreements (APSAs).

Like prior RFPs, the IE has again assessed the contract forms contained in the RFP to determine whether there are any undue biases in the pro forma contracts that could favor one type of resource option over another. Moreover, like the earlier RFPs, in the present case, benchmark options are being proposed. Accordingly, to assess the fairness of the RFP, the IE points out in this section how each of the major "product" risk characteristics, that are either captured in the pro forma contracts or presented by the cost of service benchmark option, differ among the selection options. The benchmark options in this 2017 Wind Draft RFP do not match in aggregate size the full amount of the planned development of Wyoming wind in the subject time period. The benchmarks are all planned for in-service dates in 2020 and have potential resource sizes and tie locations as follows:

- 110 MW, Foote Creek substation
- 250 MW, Aeolus substation
- 250 MW, Shirley substation
- 250 MW, Shirley substation

Summary Assessment of Risk Allocations between Seller and Buyer

As set forth below, the risks of delay and increased Facility cost allocated to PacifiCorp as the PPA buyer are notably lower than the risks allocated to PacifiCorp under the terms of the BTA. The PPA terms fix the obligations for development and performance on the PPA Seller in ways that make permitted delay and increased buyer costs unlikely for successful projects. Conversely, the BTA terms are more flexible for the BTA Developers who may obtain relief from unexpected delay and increased costs under those terms. Overall, compared to the two contract options, benchmarks present the highest risks of permitted delays and increased costs which, at least in theory and without regard to the possible mitigating impacts of prudence reviews, fall on PacifiCorp for the account of ratepayers under traditional cost of service pricing principles.

Finally, the coincident planning of a new 500-kV transmission line in Wyoming to which most of the Facilities are expected to interconnect raises a central and largely unresolved question:

> "Should the contract counterparties face even the theoretical risk of default and termination damages when they successfully complete all other aspects of their Facilities but cannot interconnect and energize those Facilities before the deadline date since the transmission line is not ready?"

The inherent contractual problem may be more difficult for PPA Sellers whose contract terms are tighter with respect to all performance issues, divorced from PacifiCorp transmission problems and more likely to yield an interpretation that default and termination damages were intended.

The BTA Developers may fare better, raising serious questions of comparable treatment. Fairness and comparability would stand out as problems even more if benchmark options were to be delayed beyond the same deadline date and PacifiCorp's actions were wholly prudent in character. This central question deserves to be resolved with specific contract provisions which clarify the contract outcomes in a fair and comparable fashion among all of the options. Comparable treatment may require that the PPA Seller and the BTA Developer be granted protection similar to the protection a prudent PacifiCorp would receive when its benchmark project was delayed. PacifiCorp understands this comparability issue regarding the potential reasons for a transmission delay and has expressed at least some willingness to negotiate risk-mitigating terms and conditions with PPA and BTA counterparties under appropriate conditions.

The sections below provide a discussion of the major product risk characteristics and how key provisions of the PPA and BTA agreements and the principles of cost of service pricing compare with respect to such risks.

Risk Allocation between Seller and Buyer in Contracts and Benchmark Options: Issue by Issue Comparison among Power Purchase Agreement (PPA) (Appendix E-2), Build and Transfer Agreement (BTA) (Appendix F-2) and Cost of Service Benchmark Pricing Principles

1. Milestone and Development Risk. Both PPA Sellers and BTA Developers have duties to meet applicable Milestones and achieve completion of the Facility or face contract consequences for delays or failures in performance.

   With respect to the PPA, milestone duties and liquidated delay and deficit damages are set forth in Section 2.3 (§2.3(d): duty to reach the Commercial Operation by the Guaranteed Commercial Operation Date) and Section 2.4 (§2.4(a): duty to provide the Required Facility Documents; §2.4(b): obligation to pay Delay Damages for failing to reach the Commercial Operation by the Scheduled Commercial Operation Date); §2.4(c): termination right for failing to reach the Commercial Operation by the Guaranteed Commercial Operation Date; §2.4(d): obligation to pay Deficit Damages for reaching Final Completion based on less than 100% of Expected Nameplate Capacity Rating). Moreover, failures to meet the requirements of §§2.3 and 2.4 are not excused in any of the circumstances listed in the following language of §2.3

   > "Without limiting Seller's obligations under this Agreement, none of the following shall excuse in any respect Seller's failure to comply in all respects with any and all provisions in this Section 2.3 and Section 2.4, no matter what the source or reason: (i) any event of Force Majeure, actual or alleged; (ii) economic hardship, including lack of money or inability to obtain financing; (iii) inability to obtain any supply of any good or service, (iv) any breakdown or malfunction of any equipment; (v) costs or taxes; (vi) anything relating to any Required Facility Document; (vii)

> Requirements of Law; (viii) anything relating to the Transmission Provider, Network Service Provider, Interconnection Provider, or Generation Interconnection Agreement; or (ix) increased cost of electricity, steel, labor, or transportation" (Emphasis added.)
>
> PPA Section 2.3

Additional and potentially more severe consequences can be applied to PPA Sellers if the COD milestone is not met (§11.1.2(b)); or the Facility construction or operation is abandoned (§11.1.2(f)). These development failures, in addition to failures to meet the PPA Seller's "blanket" obligations during development (§11.1.1(d)), can mature into a defined Event of Default, after any applicable cure period. No notice and cure applies in the case of any delay in obtaining the Commercial Operation Date by the Guaranteed Commercial Operation Date (Section 11.1.2(b)). Events of Default may result in termination of the PPA (§§11.3, 11.5).

With respect to the BTA, throughout Article 7, General Obligations of the Developer, it is clear that the Developer accepts all responsibility, and risk, for the success of developing the Facility. BTA Developers are bound to the Project Schedule (§10.6) and in particular, to the Guaranteed Substantial Completion Date (§17.1 and §29.1(c)). Developers face Delay Liquidated Damages for each day of delay beyond the Guaranteed Substantial Completion Date (§24.2). Moreover, BTA Developers face a comparable "no notice and no opportunity to cure" risk of termination when Substantial Completion does not occur by the Guaranteed Substantial Completion Date (§29.1(c)), triggering an immediate termination of the Agreement (§30.1(a)(i)). Milestone failures likewise could result in termination under §30.1(a)(ii) when triggered, after notice and 30 day opportunity to cure, by the "blanket default" provision (§29.1(f)).

Notwithstanding these similarities with the milestone duties and penalties under the PPA, the Project Schedule and other milestone provisions in the BTA contemplate more flexibility with respect to milestone performance than the PPA. The first and foremost example of this advantage enjoyed by the BTA Developer is seen in the limitations imposed on the use of Force Majeure events during the development period in the PPA. That is, in addition to the more severe exclusions from the definition of qualifying Force Majeure events, discussed further below, and the cited ineffectiveness of Force Majeure excuses in judging the critical milestone performance set forth in PPA §2.3 and §2.4, as seen above, the operative language, itself, explaining the purpose of Force Majeure excuses eliminates the use of the excuse during development in PPA §14.2.

> "14.2 Suspension of Performance. After the Commercial Operation Date, but not before, and subject to the limitations set forth in Section 14.5, neither Party shall be liable for any delay or failure in its performance under this Agreement, nor shall any delay, failure, or other occurrence or event become an Event of Default, to the extent such delay, failure, occurrence or event is substantially caused by conditions or events of Force Majeure during the continuation of the event of Force Majeure, for the same number of days that the event of Force Majeure has prevailed, . .."

(Emphasis added.)

The flexibility enjoyed by BTA Developers likely derives from the provisions of a typical Engineering, Procurement and Construction (EPC) agreement which form the basis for the scheduling and change order provisions of the BTA. In this regard, Article 10, Project Schedule, describes a two-step process during which the preliminary project schedule attached as Appendix B on the Effective Date evolves into the defined Project Schedule (§10.1) which, as PacifiCorp may direct, may include Critical Milestones and the Critical Milestone Dates which are "consistent with" or "not different from" Appendix M" (§10.1; 10.3(a)). PacifiCorp's control over the Project Schedule is clear and the Developer is explicitly made responsible for completing each Milestone by the applicable Milestone Completion Date (§§10.3(a); 10.3(c); 10.4 (no material changes without consent); 10.5 (orders to catch up schedule); 10.6 (duty to meet milestones); and 10.7(rate of progress notices)). However, PacifiCorp-Initiated Changes (§10.3(c))); Required Changes (§10.8(d) in the event of PacifiCorp's failure to fulfill any PacifiCorp Obligation under the BTA affecting the Developer's milestones (as recognized in the Project Schedule (§10.2)) (emphasis added); and the several provisions for Changes in Article 13, Change Orders, create flexibility for the Developer that does not to apply to the milestone performance of PPA Sellers.

For example, in pertinent part set forth below, Section 13.2(c) recognizes Change Order adjustments for milestone and cost problems unavailable to the PPA Seller (as cited above in PPA Section 2.3):

> "(c) Required Change Orders. Developer shall be entitled to the issuance of a Change Order pursuant to this ARTICLE 13 in connection with any circumstances which constitute a Change and which are attributable to the matters identified in subparagraphs (i) through (iii) below (each a "Required Change"):
>
> (i) Due to Change in Law, Permit **or Site Condition**[13]. If and to the extent that a change in any Law or Developer Permit after the Effective Date results in an increase in the cost of the Work or an extension of the Project Schedule.
> (ii) Change Order Due to Suspension of Work by PacifiCorp. If and to the extent that PacifiCorp suspends the Work and Developer is entitled to a Change Order pursuant to ARTICLE 16.
> (iii) Change Order Due to Non-Performance by PacifiCorp. If and to the extent that PacifiCorp fails to perform or is late in performing in any material respect any material obligation of PacifiCorp under this Agreement, provided that such failure is not the result of Developer Parties' negligence or breach of this Agreement."
> (Emphasis added; see footnote regarding Site Condition.)
>
> BTA Section 13.2(c)

[13] The reference to Site Condition in the caption of the section may be an error. The language of the section does not refer to site conditions. Furthermore, the Change Order might be seen as inconsistent with the Developer's duties under Section 3.1(b) (I) to inform itself about the conditions at the site.

In brief, the risk of milestone and development default and termination is higher for PPA Sellers than for BTA Developers.

For the benchmark options, no milestone or commercial operation deadlines, as such, apply under traditional cost of service principles. However, PacifiCorp has a duty to serve and, if the benchmark options are selected, PacifiCorp must prudently plan to have the benchmark facility on line in a timely fashion, particularly, as here, where there are tax incentives which benefit ratepayers with time deadlines. It is the IE's understanding that prudent planning, under applicable case law and **[UCA § 54-4-4(4)(a)],** is unlikely to require that any specific deadline or target commercial operation date be met, as long as the utility, based on what it knew at the time or should have known, continues to plan and identify alternatives to meet its needs prudently as permit and other development problems occur. No formal definition of Force Majeure would limit its ability to proceed free of penalties as long as prudence continued to apply as it took action to counter events outside its control. While PacifiCorp could prudently decide to cancel an unsuccessful or uneconomic benchmark, and seek recovery of prudently incurred costs[14], no default and termination risk as such applies to benchmark projects. Even if schedules and target dates slip, as long as PacifiCorp continues to review alternatives prudently, and then prudently decides to continue, it will be entitled to finish the benchmark project without interruption and seek to recover its costs in rates. Accordingly, under traditional cost of service principles, ratepayers will experience the full impact of delay costs prudently incurred when a benchmark project cannot be finished on time.

2. <u>Force Majeure Mitigation of Performance Risks [with Major Exclusions]</u>.

In Appendix Z of the BTA, Force Majeure is generally defined as follows:

> "Force Majeure" means an event or cause not reasonably anticipated as of Effective Date, which is not within the reasonable control of or caused by the fault or negligence of the party affected thereby, and which the affected party has been unable to remedy, prevent or overcome, despite the use of reasonable care or exercise of diligence consistent with Prudent Industry Practices."

Force Majeure is generally defined in Section 14.1 of the PPA as follows:

> "Force Majeure" or "an event of Force Majeure" means an event that (a) is not reasonably anticipated as of the date hereof, (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.

[14] Under UCA § 54-17-304(4)(b), PacifiCorp now is able to seek prior review of whether to proceed with an earlier approved project and to recover its costs to date and termination expenses if the Commission decides not to approve continuation. Further, under UCA § 54-17-304(5)(a)(I) and (ii), PacifiCorp is not obligated to follow Commission determinations and can later seek recovery of the prudently incurred costs of continuing a questionable project.

Each general standard, however, is highly qualified by exclusions, and exceptions to exclusions, which are embedded in the complete definitions in each agreement. Those exclusions and exceptions vary dramatically between the PPA and the BTA. Moreover, as shown above, other provisions of the PPA and the BTA qualify and limit the *effectiveness* of a Force Majeure event as an excuse for the delay or the failure of the contract Party to perform. These other provisions of the PPA and the BTA also vary in significant ways between the two contract forms.

These differences in the details of the definitions and the application of the Force Majeure concept will be discussed further below. For purposes of discussion, it will be assumed, contrary to the apparent meaning of Section 14.2 of the PPA, that Force Majeure is at least in theory available as an excuse during the PPA Seller's development period.

Since no formal Force Majeure clause is operative with respect to benchmark options, PacifiCorp would have all the flexibility available under prudence principles for excusable delays. As long as continued development was prudent under the circumstances, PacifiCorp could incur the costs associated with delayed performance without significant risk of later being unable to recover those costs from ratepayers.

3. <u>The Force Majeure Treatment of Permits and Required Facility or Project Documents</u>. During development of a Facility, obtaining all Permits required, entering into equipment supply and construction agreements and closing construction financing, all in a timely fashion, present significant risk to the development. Problems in these regards can be responsible for late completion of milestones or even the abandonment of the development effort in the worst cases. Both PPA Sellers and BTA Developers would normally hope, in appropriate circumstances, for some mitigation of these risks through the Force Majeure provisions of the contract forms. Nonetheless, the full details of the Force Majeure definitions themselves contain exclusions that limit full access to Force Majeure relief. In short, even if other provisions of the contract forms did not restrict the application of Force Majeure, the definitions would limit the possibility of relief from these problems at least to the extent set forth in the exclusions.

   In Section 14.1 of the PPA, the Force Majeure is defined explicitly to limit by exclusion certain events. In pertinent part, Force Majeure is limited as follows:

> "Notwithstanding the foregoing, none of the following constitute Force Majeure: . . .
>
> (vi) delay or failure of Seller to obtain or perform <u>any Required Facility Document[15] unless due to a Force Majeure event</u>, (vii) any delay, alleged breach of contract, or failure by the Transmission Provider, Network Service Provider or Interconnection Provider <u>unless due to a Force Majeure event</u>; . . . (ix) Seller's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to transmission

[15] Required Facility Documents include Permits is the PPA, §1.1.

> owner, Transmission Provider or Interconnection Provider, unless due to a Force Majeure event; . . ." (Emphasis added.)
> PPA Section 14.1

Exclusion (vi) is discussed in this subsection and other exclusionary clauses are discussed below. As indicated in the footnote, Required Facility Documents are defined in Section 1.1 to include all Permits, other authorizations and agreements necessary for development, construction, operation and maintenance of the Facility. Required Facility Documents are also cross referenced to include those in Exhibit 3.2.3. Accordingly, the limitation, "unless due to a Force Majeure event," was needed in clause (vi), above, to allow delay or failure of Seller to obtain its required permits, authorizations and agreements to be excused if "due to a [independent][16] Force Majeure event". However, the exclusion of a failure or delay in the permit process is the general rule and the exception that applies when an independent Force Majeure event is the cause of the failure or delay should be seen as a narrow exception to the broad general exclusion. For example, if a tornado or a lightning strike destroys the building, and its contents, where the permitting authority resides, that independent Force Majeure event could for a period of time make a delay in issuing a permit realistic. Except as the PPA provides elsewhere, PPA deadlines regarding Required Facility Documents would therefore be excused to the extent allowed when the problem events meet the narrow Force Majeure definition. On the other hand, such failures can still mature into a Seller Event of Default under Section 11.1.2(e) and 10.1.2(f) after 180 days, the limit to any Force Majeure event under Section 14.6.

The PPA, however, does *provide otherwise* for certain critical duties of the PPA Sellers set forth in Sections 2.3 and 2.4. In other words, events of Force Majeure, captured by the literal words of the narrow definition, are nonetheless ineffective to excuse failures to perform under Section 2.3 and Section 2.4, including failures to satisfy the Guaranteed Commercial Operation Date, to post Project Development Security or Default Security, to obtain the Required Facility Documents, to pay Delay Damages after the Scheduled Commercial Operation Date or to pay Deficit Damages for reaching Final Completion with less than 100% of the expected capacity. See the excerpted language of Section 2.3, above.

Finally, with respect to Force Majeure and the deadline date for the Guaranteed Commercial Operation Date, the following Section 14.5 of the PPA reaffirms the *ineffectiveness* of a Force Majeure excuse, such as one based on permit or document delay:

> "14.5 Limitation on Force Majeure Relief. To the extent a Force Majeure event provides a Party relief under this Agreement, such Force Majeure relief will not excuse Seller from achieving the Guaranteed Commercial Operation Date no later than December 31, 2020. In no event may an event of Force Majeure excuse Seller from achieving the Guaranteed Commercial Operation Date on or prior to December 31, 2020."

[16] Clause (iv) of this Force Majeure definition makes reference to equipment breakdowns caused by an independent event of Force Majeure, allowing the interpretation elsewhere in the definition that "independent" events were inferred to be the meaning of the exceptions to the stated exclusions.

Under the BTA, the timely completion of comparable Project Documents, defined in Appendix Z of the BTA, does appear to be Developer's responsibility under various provisions of Section 4 and Section 10.6. However, delays in obtaining Project Documents are not excluded from the BTA Force Majeure definition. In addition, the definition of Force Majeure in Appendix Z contains some qualified permit relief for the Developer. A permit and approval exclusion to the definition is first stated but then qualified as follows:

> "none of the following shall constitute Force Majeure: . . . (c) delay or failure by Developer to obtain any Developer Permit, PacifiCorp Regulatory Approval or Developer Regulatory Approval, other than the delay or failure to obtain Developer Permits, PacifiCorp Regulatory Approvals or Developer Regulatory Approvals occasioned by: (i) revocation, stay, or similar action by a Governmental Authority of a Permit, PacifiCorp Regulatory Approval or Developer Regulatory Approval after issuance thereof by a Governmental Authority; (ii) the failure of a Governmental Authority to comply with rules, procedures or other applicable Law applicable to such Governmental Authority; or (iii) another Force Majeure;. . "
> (Emphasis added.)
>
> BTA, Appendix Z, "Force Majeure" definition.

In the first instance, it is important to note that the exclusions from the BTA Force Majeure definition are in general more limited than the exclusions from the PPA definition. Not included as exclusions to the BTA Force Majeure definition are the delay in obtaining Project Documents; any delay or failure by the Transmission Provider, Network Service Provider or Interconnection Provider; and Developer's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to transmission owner, Transmission Provider or Interconnection Provider. Provided that the general restrictions on the BTA meaning of Force Majeure are observed[17], BTA Force Majeure definition should in theory capture Project Documents, third party interconnection and transmission problems and the Developer's interconnection and transmission problems that involve no Developer fault.

Moreover, the exceptions to the cited exclusion for Developer Permits in the BTA mean that time-consuming appeals, governmental miscues and other Force Majeure events causing permit delay or failure may result in excused permit or approval delays.

Accordingly, the PPA and BTA provisions are far from comparable. BTA Developers fare significantly better in avoiding the risk of defaults due to delays in obtaining permits

[17] "Force Majeure" means an event or cause not reasonably anticipated as of Effective Date, which is not within the reasonable control of or caused by the fault or negligence of the party affected thereby, and which the affected party has been unable to remedy, prevent or overcome, despite the use of reasonable care or exercise of diligence consistent with Prudent Industry Practices." Appendix Z, BTA.

and necessary documents than do PPA Sellers. PPA Sellers are prevented from using Force Majeure and other similar problems as excuses for any failure to perform under Sections 2.3 and 2.4 and at most, are entitled to 180 days of Force Majeure relief from milestone failures due to permit or document delay caused by independent Force Majeure events. In fact, if PPA Section 14.2 is read literally, no events of Force Majeure provide PPA Sellers relief during the development period. Accordingly, PacifiCorp experiences higher risks of uncompensated delays and cost increases as a result of the flexibility in performance accorded BTA Developers with respect to permit and documentation delays.

With respect to permit and document delays, the benchmark options under traditional cost of service principles fare better than either the PPA Sellers or the BTA Developers. Permit delays for reasons outside the control of the utility, and ordinary delays entering into Project Documents, such as the Turbine Supply Agreement or the Balance of Plant Agreement, that reveal no lack of diligence would generally be no basis for a finding of imprudence, provided that the utility continued to plan, make progress and consider alternatives and the impacts of delay prudently. No formal Force Majeure clause limits PacifiCorp ability to show the prudence of its planning when permit problems, or other development difficulties, occur. There is little risk of an imposed project cancellation due to mere delays in obtaining permits.

4. <u>Interconnection and Transmission Risks</u>. It is important as a threshold matter to comment further on the effects of certain PPA Force Majeure exclusions on the critical interconnection and transmission duties of PPA Sellers. Like the permit exclusion, the interconnection exclusions are analyzed at first as being excluded from Force Majeure under the words of the PPA and then are seen as being recaptured into the meaning of Force Majeure by "independent" Force Majeure events. The pertinent words of the Force Majeure definition, given above, are reproduced here for emphasis as follows:

> (vii) any delay, alleged breach of contract, or failure by the Transmission Provider, Network Service Provider or Interconnection Provider <u>unless due to a Force Majeure event</u>; . . . (ix) Seller's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to transmission owner, Transmission Provider or Interconnection Provider, <u>unless due to a Force Majeure event</u>; . . ." (Emphasis added.)
> PPA Section 14.1

Two comments are appropriate. First, the exclusion of a failure or delay by the transmission entities or by the Seller under the GIA is the general rule. The exception that applies when an independent Force Majeure event is the cause of the failure or delay should be seen as a narrow exception to the broad general exclusion. Secondly, these words which narrowly extend Force Majeure relief to transmission and interconnection problems are, like permit and document problems, rendered <u>ineffective</u> by the above-cited language of Section 2.3. Since such provisions of Section 2.3 are much more restrictive than merely limiting the Force Majeure definition, they are reproduced for emphasis as follows:

"Without limiting Seller's obligations under this Agreement, none of the following shall excuse in any respect Seller's failure to comply in all respects with any and all provisions in this Section 2.3 and Section 2.4, no matter what the source or reason: (i) any event of Force Majeure, actual or alleged; (ii) economic hardship, including lack of money or inability to obtain financing; (iii) inability to obtain any supply of any good or service, (iv) any breakdown or malfunction of any equipment; (v) costs or taxes; (vi) anything relating to any Required Facility Document; (vii) Requirements of Law; (viii) anything relating to the Transmission Provider, Network Service Provider, Interconnection Provider, or Generation Interconnection Agreement; or (ix) increased cost of electricity, steel, labor, or transportation" (Emphasis added.)
PPA Section 2.3

In short, under the PPA, duties under Section 2,3 and Section 2.4 are unexcused by reason of not only Force Majeure, but also "(vi) anything relating to any Required Facility Document; (vii) Requirements of Law; (viii) anything relating to the Transmission Provider, Network Service Provider, Interconnection Provider, or Generation Interconnection Agreement."

Beyond this threshold commentary, the central importance of the interconnection and transmission facilities to the overall risk of developing the Facility successfully must be noted. In short, unless all of the interconnection and transmission facilities are completed in time, the PPA Seller and the BTA Developer could face termination and large damages to PacifiCorp notwithstanding the fact that the delay and/or failure causing the termination occurred solely on the System-side of the Point of Interconnection and without the fault of the PPA Seller or the BTA Developer. This prospect is discussed further in the following paragraphs.

The interconnection and transmission facilities have the following common characteristics affecting risk in the PPA and the BTA:

- Both the PPA Seller and the BTA Developer have a duty to build the Interconnection Facilities on their side of the Point of Interconnection, including the Project Substation and the Interconnection Line (RFP App. A.1, §6.4; A.2 (definitions); A.3, §10); see also: PPA, §6.3
- Both the PPA Seller and the BTA Developer have guaranteed deadline milestones for the COD and the Substantial Completion, respectively;[18]
- Both the PPA Seller and the BTA Developer face Delay Damages for missing the scheduled deadline milestone (PPA, §2.4(b) (defined in §1.1 in terms of

[18] For the PPA, the deadline calendar date is specified as December 31. 2020 (§§1.1 and 14.5). For the BTA, the date in question is not specified in the form as of now (App. Z).

PacifiCorp's Cost to Cover, a replacement power/Green Tag calculation); BTA, §24.2 (amount to be negotiated);

- Both the PPA Seller and the BTA Developer face automatic termination for missing the guaranteed deadline date (PPA, §11.1.2(b); BTA, §29.1(c));
- Both the PPA Seller and the BTA Developer which have suffered termination for this reason generally face all remedies and damages provided to PacifiCorp in law (PPA, §§2.5, 11.3(c) and 11.5 (presumably termination for fault triggers cover damages for the unexpired term); BTA, §§30.1(b), 30.3(b) (as a construction-like form, cover damages would not be based on replacement power costs since power is not the product being purchased)[19].

With respect to the interconnection and transmission risks on the PPA Seller in the current form of agreement, the prospects of managing those risks are affected by the following factors:

- As stated in this section, above, interconnection and transmission problems are generally excluded from the Force Majeure definition except as narrowly recaptured by independent Force Majeure events;
- §2.3 eliminates Force Majeure and anything relating to a multitude of causes (including interconnection and transmission entities and agreements) as excuses for failures of §2.3 and §2.4 performance;
- §14.2 appears to eliminate the use of Force Majeure at any time prior to the Commercial Operation Date;
- §14.5 limits any applicable Force Majeure event to assure that the Guaranteed COD never falls after December 31, 2020;
- Numerous provisions of the PPA distinguish the identity of PacifiCorp in its merchant function from PacifiCorp in its transmission function, each attempting to prevent any claims against, or involvement of, PacifiCorp in its transmission function under the PPA or any role of the Generation Interconnection Agreement under the PPA (§§1.2.5, 4.5, 6.3 and 9.3).

With respect to the interconnection and transmission risks on the BTA Developer in the current form of agreement, the prospects of managing those risks successfully are affected by the following more favorable factors in the BTA:

- PacifiCorp will be invested in the Development Assets associated with the Facility from the time of the Closing and the payment of the Purchase Price;
- The PacifiCorp investment continues to grow as Progress Payments are made and equipment is delivered to the Site (§§2, 3 and 20.6);
- The BTA form does not contain the many provisions in the PPA which force a distinction between the identity of PacifiCorp in its merchant function from PacifiCorp in its transmission function;

[19] §30.3(b) is unclear that the intent is to allow PacifiCorp to recover cover damages based on the excess cost to complete the Facility. Such cover damages are normally given in terms of the sum of [Progress Payments to date] and [the cost to complete], less the Contract Price; see also: §25.4 (Limitation of Liabilities to 100% of the sum of the Purchase Price and the Contract Price) which creates confusion when compared to §30.1(b)

- PacifiCorp's continuing financial interest will likely create an objective to optimize that interest as PacifiCorp exercises its rights and remedies with respect to any interconnection and transmission problems that arise;
- As set forth, above, in Section 3, the exclusions from the BTA Force Majeure definition are in general much more limited than the exclusions from the PPA definition;[20]
- Unlike the PPA, the use of Force Majeure is not specifically limited to the period after the operation of the Facility commences and does not (presently) have a date certain deadline of December 31, 2020 with respect to the Guaranteed Substantial Completion Date;
- Unlike the PPA in §2.3, the BTA does not appear to list a group of events and interconnection and transmission entities or agreements that cannot be an excuse in any way for any Developer interconnection and transmission problem that involves no Developer fault;
- The BTA has a formal process for the scheduling and re-scheduling of Project activities which, among other things, recognizes "PacifiCorp Obligations" which are the duties which PacifiCorp must perform under the BTA "in order for the Developer to achieve the Milestone Completion Dates. " (§10.2);
- The BTA has a formal process in §13 for issuing Change Orders which acknowledge the effects of changes on the Contract Price and the Guaranteed Substantial Completion Date; and, for "PacifiCorp-Initiated Changes" and "Required Changes" (§§13.2(b) and 13.2(c)), PacifiCorp will issue a "Change Order having regard to all such circumstances as is just and equitable . . " (§13.1(b)); and
- "Required Changes" (§13.2(c)) include changes due to change in any Law or a Developer's Permit which result in an increase in cost or an extension of the Project Schedule, suspension of Work by PacifiCorp and a board description of non-performance under the BTA.

Each of the above factors contributes to the prospects of the BTA Developer managing the interconnection and transmission risks successfully, particularly when facing interconnection and transmission problems that involve no Developer fault. The BTA Developer could use the avenues provided by the BTA to attempt to seek relief from interconnection delays based upon the broader Force Majeure definition in the BTA; the formal re-scheduling and change order processes (absent in the PPA); and the implied obligations of PacifiCorp, common to both forms, not to impair its counterparty's ability to perform.

[20] Not included as exclusions to the BTA Force Majeure definition are the delay in obtaining Project Documents; any delay or failure by the Transmission Provider, Network Service Provider or Interconnection Provider; and Developer's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to transmission owner, Transmission Provider or Interconnection Provider. Provided that the general restrictions on the BTA meaning of Force Majeure are observed, BTA Force Majeure definition should in theory capture Project Documents, third party interconnection and transmission problems and the Developer's interconnection and transmission problems that involve no Developer fault.

With respect to implied obligations of PacifiCorp under each of the forms, the PPA Seller and the BTA Developer cannot fulfill their obligation to interconnect and complete the Facilities unless the Wind Turbines are energized. "Energization" is a formal requirement of Appendix AA of the BTA for Mechanical and Substantial Completion. Energization would be a condition of the Commercial Operation Date as a part of the demonstration that Interconnection Facilities have been constructed and the Facility is interconnected in accordance with the GIA. Energization should be seen as an implied obligation of PacifiCorp under both forms.

In comparison to the PPA, the BTA has many more favorable provisions that may allow the Developer to avoid damages and/or termination when no fault of the Developer affects its interconnection performance.

Under traditional cost of service principles, provided that planning and construction exhibit prudence, benchmark options which experience capital cost increases and/or interconnection delays for electric interconnections during development or construction phases enter rate base at the higher costs resulting from such increases. Ratepayers are expected to absorb the risk of prudent capital cost increases. Among the three options, the PPA, the BTA and the benchmark approach, the benchmark approach exposes ratepayers to the highest risk of interconnection cost increases and schedule delays.

Unless all of the interconnection and transmission facilities on both sides of the POI are completed in time, the PPA Seller and the BTA Developer could *in theory* face termination and large damages to PacifiCorp notwithstanding the fact that the delay and/or failure causing the termination may have occurred solely on the System-side of the Point of Interconnection and without the fault of the PPA Seller or the BTA Developer. In the latter case, little good policy and no equity would support the result that these counterparties suffer loss of investment when the entities controlling the System-side of the POI caused the delay or failure. Comparable treatment would require that the PPA Seller and the BTA Developer be granted the same protection a prudent PacifiCorp would receive when its benchmark project was delayed.

5. <u>Change in Law Risk</u>. The planned Facility is a utility scale wind project. Each Facility may have hundreds of large 1.5 to 3.0 MW Wind Turbine Generators (WTG). Many will be sourced from foreign suppliers which have dominant shares of the wind manufacturing market. Due to the present uncertainty regarding the Trump Administration's trade and tax policies, it will be hard to eliminate the risk that import tariffs or fees, border adjustment taxes and similar charges and costs will be added to or subtracted from the expected cost to procure foreign-sourced WTGs. The ability to procure foreign-sourced WTGs from certain countries may be impacted, resulting in the purchase of higher priced WTGs from countries with more accommodating agreements with the U.S. As a result, change in Law risk has a significance that may have been far less in the recent past.

   The applicable provisions of the BTA result in a risk that costs to PacifiCorp may increase to reflect certain Force Majeure and Change in Law events or occurrences. In light of the well-understood fixed pricing provisions of the PPA, no comparable risk exists for PacifiCorp under the PPA. Moreover, the Requirements of Law are specifically included as a reason in §2.3 that cannot be used to excuse any obligation under §2.3 and §2.4 (covering, among others, the duty to reach COD and to pay Delay and Deficit Damages in the applicable cases). Compare:

(A) PPA Sections 5.1.1 (Test Energy priced per MWh at 75% of the Firm Market Price Index), 5.1.2 (Net Output priced per MWh at the Contract Price), 5.1.3(b) (Compensable Curtailment Energy priced per MWh at the Compensable Curtailment Price) of the PPA

to

(B) BTA Sections 10.2 (PacifiCorp Obligations to support Developer's ability to meet Milestones), 10.8(d) (day for day extension and possible costs increases for failure of PacifiCorp's Obligations, 13.2(b) (PacifiCorp-Initiated Changes), 13.2(c) (Required Changes) of the BTA. Required Changes explicitly include changes in any Law, for which an extension of the Project Schedule and/or an increase in the Contract Price may result (§§13.1(b) and 13.2(d)).

Under traditional cost of service principles, events outside the control of the utility, including, in particular, changes in law, would not result in imprudence disallowances as long as the utility continued to adapt its development efforts to the changed circumstances in a prudent fashion. As a result, permit opposition and delay, changes in law relating to environmental control requirements, and other similar occurrences would result in prudently incurred delay and scope-change costs. Ratepayers have traditionally absorbed costs such as these which a prudent utility could not reasonably avoid.

Among the three options, the highest risk that Change in Law results in higher costs and possible delays resides with the benchmark option. The BTA represents the next highest risk to ratepayers and the PPA represents the lowest risk,

6. Risk of Capital Cost Increases and Capital Additions. Much of the discussion in the prior paragraphs is applicable here. Permit delays and changes, documentation delays and changes, changes in the cost of financing agreements, delays and changes in the cost of the interconnection, and changes in Law that create new or different environmental controls or tax burdens - - all may result in higher capital costs for the Facility both before or after it goes into operation.

   Whether any event or change in circumstances results in a permitted increase in the Facility costs passed on to ratepayers depends on the form of agreement and the nature of the change. As stated above, the applicable provisions of the BTA result in a risk that capital costs assigned to PacifiCorp may increase to reflect certain Force Majeure and Change in Law events or occurrences. On the other hand, the fixed pricing provisions of the PPA generally result in no comparable risk under the PPA. Moreover, the Requirements of Law are specifically included as a reason in PPA §2.3 that cannot be used to excuse any obligation under §2.3 and §2. The applicable PPA provisions are: Sections 5.1.1 (Test Energy priced per MWh at 75% of the Firm Market Price Index), 5.1.2 (Net Output priced per MWh at the Contract Price), 5.1.3(b) (Compensable Curtailment Energy priced per MWh at the Compensable Curtailment Price) of the PPA.

The applicable BTA provisions are: Sections 10.2 (PacifiCorp Obligations to support Developer's ability to meet Milestones), 10.8(d) (day for day extension and possible costs increases for failure of PacifiCorp's Obligations, 13.2(b (PacifiCorp-Initiated Changes), 13.2(c) (Required Changes) of the BTA. Required Changes explicitly include changes in any Law, for which an extension of the Project Schedule and/or an increase in the Contract Price may result (§§13.1(b) and 13.2(d)). During operation of BTA resources by PacifiCorp, capital additions and retrofits would, except for warranty items, be at the risk and cost of PacifiCorp.

Accordingly, under the BTA, PacifiCorp is exposed to risks of capital cost increases, both before and after the Commercial Operation Date, which are simply not applicable under the PPA.

Among the three options, the highest risk that Change in Law results in higher costs and possible delays resides with the benchmark option. The BTA represents the next highest risk to ratepayers and the PPA represents the lowest risk,

7. Performance Risk and Performance Damages. Under the PPA, a risk exists that the full Facility cannot be built. While technically this may not be a "performance" risk more often used to describe operating problems, if this under-building materializes, the PPA Seller will be forced to pay Deficit Damages defined in §1.1 (§2.4(d). Under §24.3 of the BTA, a risk exists that the WTGs will not pass an initial Performance Test which PacifiCorp may request under Appendix AA §§(D) and (E). Performance Liquidated Damages (§24.3) (the net present value over 10-year PTC period of the grossed up pre-tax value of the PTC times the amount of the expected annual energy losses due to the Project not meeting the Power Curve guarantee) will be calculated as set forth in Appendix AA based on the Performance Guarantee (98% of the nominal calculated Project annual energy yield computed on the basis of the calculated power curve from the Power Curve Test).

   For the PPA, the performance risk during operation derives from the per MWh pricing (assigning, among other risks, the weather, wind and power curve risks to Seller) and from the availability guarantee in §6.12 (§6.12.1 (Guaranteed Availability is 95%). With respect to the pricing on a per MWh basis, PacifiCorp experiences a savings in payments to the PPA Seller when the Net Output from the Facility declines. The full amount of those savings is available to pay the cost of replacement power. The Liquidated Damages for the Output Shortfall due to a failure of the Guaranteed Availability is provided for in the following section:

   > 6.12.2 Liquidated Damages for Output Shortfall. If the Availability in any given Contract Year falls below the Guaranteed Availability for that Contract Year, the resulting shortfall shall be expressed in MWh as the "Output Shortfall." The Output Shortfall shall be calculated in accordance with the following formula:
   >
   > Output Shortfall = (Guaranteed Availability – Availability) x Expected Energy.

> If an Output Shortfall occurs in any given Contract Year, Seller shall pay PacifiCorp liquidated damages equal to the product of (a) the Output Shortfall for that Contract Year, multiplied by (b) PacifiCorp's Cost to Cover for that Contract Year. Each Party agrees and acknowledges that (i) the damages that PacifiCorp would incur due to the Facility's failure to achieve the Guaranteed Availability would be difficult or impossible to predict with certainty and (ii) the liquidated damages contemplated by this provision are a fair and reasonable calculation of such damages. (Emphasis added.)

In a default circumstance, when the PPA Seller is in breach for sales to third parties (§11.1.2(c)), the penalty is also based on PacifiCorp's Cost to Cover under §11.2.1.

Under the BTA, apart from the Performance Testing initially done under Appendix AA, there are no continuing performance tests since the capital asset has been transferred to PacifiCorp for operation. Accordingly, BTA Developers are exposed to little risk of paying the Cost to Cover (replacement power costs in excess of a nominal contract price for power) and PacifiCorp has little protection from the risk of incurring full replacement power costs for their own account.

Provided that operating problems do not arise from imprudence, availability shortfalls experienced by benchmark options, under traditional cost of service principles, would not result in either a reduction in the rate base recovery of the benchmark capital costs or the inability of the utility to recover the full costs of replacement power from ratepayers. Ratepayers are expected to absorb the risk of prudently incurred replacement power costs

8. Delay Damages. Under Section 2.4(b) of the PPA, Seller is required to pay daily Delay Damages if the Commercial Operation Date occurs after the scheduled date. The damages are defined as follows:

   "Delay Damages" for any given day are equal to (a) the Expected Energy, expressed in MWhs per year, divided by 365, multiplied by (b) PacifiCorp's Cost to Cover.

   Under the BTA, for each day after the Substantial Completion Guaranteed Date has been missed, Delay Liquidated Damages are provided for in §24.2 as a daily rate to be negotiated depending on the actual Facility for two periods, the first 31 days and for all days thereafter.

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

9. Lender Rights and Coordination. The PPA no longer has a section devoted to satisfaction of interim milestones such as construction financing which was in prior versions of the PPA in §2.2. In Section 8.4,1, the Security Interests required to be given by PPA Sellers to PacifiCorp are made subordinate in right only to the interests of Senior Lenders defined to mean those holding senior security interests. In the event of notice to PacifiCorp of foreclosure, an Event of Default under the PPA arises unless within 10 days the action is stayed, the amount due paid or bonded (§11.12(d). However, when Senior Lenders exercise their remedies, no Event of Default arises for that fact alone (§11.6).

   In light of the provision for Progress Payments to BTA Developers (Article 3), there appear to be no references to lenders or financing parties which apply to BTA Developers in the BTA.

   In connection with its capitalization of the benchmark options, PacifiCorp will be in regular negotiations with its lenders and its sources of equity (through its ultimate parent). Since no disclosure of PacifiCorp's plans, and estimated costs, to raise capital for the benchmark options has been made to date, the IE is unable to assess the financial impacts on the affected utility for comparison or any other purposes. Provided that capital formation is prudently planned and implemented, ratepayers would be expected to incur all costs incurred in connection with raising capital for the benchmark resources.

10. Events of Default and Termination Damages. Subject to no relief from the Force Majeure clause or from the many other potential problems relating to permits, documentation, interconnection and the like listed in §2.3, PPA Sellers must complete the critical milestones in §2.3 and pay the Delay and Deficit Damages in §2.4 when there are shortfalls in performance. If the COD is not achieved by the guaranteed date, an immediate Event of Default arises under §11.1.2(h). Under the other subsections of §11.1.2, various problems in Seller performance mature into Events of Default after the applicable periods for cure. When a prohibited sale to third parties has occurred under §11.1.2(c), the remedies include the payment to PacifiCorp of PacifiCorp's Cost of Cover for the undelivered Net Output. During the pendency of an Event of Default and after termination, which the non-defaulting Party has a right to pursue on account of the Event of Default, the non-defaulting Party has all rights and remedies available at law and in equity (§§11.3 and 11.5). In such a case, PacifiCorp as the non-defaulting Party could seek the damages for the cost of cover during the unexpired portion of the Term.

    In comparison, for BTA Developers, one milestone failure, failure to reach Substantial Completion by the guaranteed date (§29.1(c)), and several default which are arguably not subject to cure (§§29.1(d) and (g)), are automatic Events of Default without any further period to attempt a cure. Termination occurs automatically for the Substantial Completion Event of Default (§30.1(i)), but for the other Events of Default, an additional opportunity exists to avoid termination (§30.1(ii)). When a Developer is in default, PacifiCorp has a range of remedies of the type normally held by owners which have made progress payments and which now face a failing construction project. Step-in rights are available (§29.3(a)). Upon termination, the range expands to include recovery of the excess cost incurred to complete the Facility (§30.3(b)).[21] Unlike the PPA, it should be noted that the provision for Project Schedule revisions in §10.1 and the prospect of PacifiCorp-Initiated Changes and other Required Changes under §13.2 create the prospect that Events of Default for the BTA Developer may be avoided by flexibly extending deadlines.

Accordingly, PPA Sellers face higher risks of default and termination under the default provisions of the PPA than BTA Developers face under the counterpart provisions of the BTA.

As indicated previously above, no default and termination risk as such applies to benchmark projects. Even if schedules and target dates slip, as long as PacifiCorp continues to review alternatives prudently, and then prudently decides to continue, it will be entitled to finish the benchmark project without interruption and seek to recover its costs in rates. Accordingly, under traditional cost of service principles, ratepayers will experience the full impact of delay costs prudently incurred when a benchmark project cannot be finished on time.

Merrimack Energy has identified a number of contract provisions that are onerous to both PPA and BTA bidders. The IE is concerned that on its face the contract risk provisions could discourage bidders from participating in this solicitation. While there are complex provisions that will need to be negotiated as part of a comprehensive contractual arrangement taking into account both the generation component and the transmission component, we have several recommendations regarding the contract provisions:

- PacifiCorp could revise the provisions of the contract associated with transmission completion risk as well as other risks mentioned in the above contract review;
- If the provisions identified in this section of the report are time consuming to address, we would encourage PacifiCorp to provide a clear message to bidders that the contract is a starting point for negotiations but that PacifiCorp is committed to negotiate a contract that addresses the key risk provisions;
- PacifiCorp should allow the bidders to either submit a redline of the contract with its proposal or provide a separate document identifying the issues that are viewed by the bidders to be "deal killers". Allowing bidders the opportunity to identify the most onerous risk provisions could serve to guide PacifiCorp in revising contract provisions. The final contract with input from the bidders and other participants could then be provided only to the shortlisted bidders who could incorporate their perception of the contract risk in their best and final prices;

In conjunction with this suggestion, it may be appropriate to include the best PPAs and BTA options as part of the overall shortlist rather than potentially eliminating PPA

[21] The language of §30.3(b)(iii) frames the payment obligation as "the positive difference, if any, obtained by subtracting from the Contract Price PacifiCorp's cost to replace or otherwise have performed, as determined and calculated by PacifiCorp in its discretion, any Work that Developer was otherwise obligated to provide during the remaining term of this Agreement". This formulation seems to be error.

options at this stage because the PPA bidder included a significant risk premium in its pricing.

VII. Conclusions and Recommendations

Based on Merrimack Energy's review of the RFP and related information, the conclusions and recommendations of the IE are presented as follows:

Conclusions

- The RFP documents and process are generally consistent with the Utah Admin. Code, Regulations and Statutes pertaining to the requirements for the design and development of the competitive bidding process. The IE believes that PacifiCorp has adequately addressed most of the requirements listed in the Statutes. However, under the current structure of the RFP it is not certain if the solicitation process will lead to the acquisition and delivery of electricity at the lowest reasonable cost to the retail customers. The IE and others have suggested revisions to the RFP which should hopefully result in a more competitive process that will verify the IRP action plan identified by PacifiCorp without extending the solicitation process schedule, which could jeopardize the potential benefits to customers;

- The integration of the wind generation resources in conjunction with a new 140-mile 500 kV transmission line from the Aeolus substation to the Bridger/Anticline substation (Aeolus to Bridger/Anticline transmission line) could pose risks to bidders and consumers if the transmission project is not built on time to allow bidders or benchmark resources to achieve Production Tax Credit ("PTC") benefits;

- The 2017R RFP is a reasonably transparent RFP, with a significant amount of information provided to bidders on which the bidders could base their proposals;

- The 2017R RFP is designed to provide the same information to all bidders including the benchmark options;

- The products sought in this RFP are clearly defined and the information required for each type of resource alternative is specified in the RFP in a clear and concise manner;

- The RFP documents clearly describe the products requested, the requirements of bidders, the evaluation and selection process, and the risk profile of the buyer. In this regard, there is sufficient information to allow bidders to assess whether or not to compete, the product of choice to bid to be most competitive, and the process by which their proposals will be evaluated;

- There are a number of safeguards included in the solicitation process which should ensure that all bidders will have access to the same information with no undue benefit for the benchmark bid;

- Parties have raised the issue of ensuring comparability for resource evaluation, notably ensuring that utility benchmarks and third-party PPA and Build Transfer bids are required to compete based on the same set of rules or on a level playing field. The IE also views comparability to be the most challenging issue in a solicitation process in which utility-owned resources compete with third-party resources. The nature of these resources is very different to begin with. Third-party PPA options submit a price schedule that is firm at the time of submission. Changes in the cost of equipment or market prices can affect the final economics either positively or negatively, with the bidder absorbing the risk of higher project costs or enjoying the benefits or lower project costs. Utility-owned options, on the other hand are submitted as reasonable estimates. If costs increase, the utility could request the ability to pass through the costs to customers assuming the costs are deemed to be prudently incurred. Cost decreases, on the other hand, are passed through to customers. Given the different risk profiles, contract terms, etc. it is extremely difficult to create a fully level playing field on which both types of resources can compete. Merrimack Energy has proposed several ways to create a more level playing field in this solicitation.

- The evaluation process and quantitative methodologies developed by PacifiCorp for undertaking the initial price screening evaluation (spreadsheet model formerly referred to as RFP Base Model) and for selecting the final short list (System Optimizer and PaR models) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the model methodology is consistent with and likely exceeds industry standards applied by others for conducting such a price and risk analysis. While the spreadsheet model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others, notably a comparison of the costs and benefits for each proposal. The portfolio evaluation and risk assessment methodologies are very detailed and are generally pertinent to the requirements of the Energy Procurement Resource Act.

- The evaluation and selection process is a comprehensive process designed to evaluate the cost implications associated with different resource portfolios, the important non-price factors required in the Act that influence project viability, and assesses the risk parameters associated with the portfolios.

- PacifiCorp met the requirements of Utah Admin. Code R746-420-1(2) and the Scheduling Order in Docket No. 17-035-23 by providing the IE with data, information and models necessary for the IE to analyze and verify the models. PacifiCorp provided the IE with the latest version of its price screening spreadsheet model that will be used for the phase 1 shortlist evaluation as well as the latest input assumptions, which may be subject to revisions.

Recommendations

- Both Merrimack Energy and UAE have raised issues with regard to comparability associated with the risk issues allocated to each resource type (i.e. PPA, BTA, and benchmark) and comparability associated with the resources evaluation process (contract term/evaluation horizon). Merrimack Energy has undertaken a detailed assessment of the Power Purchase Agreement ("PPA") and Build Transfer Agreements ("BTA") and identifies the risks in each contract. Merrimack Energy concludes that there are very different risk provisions in the PPA and BTA agreements which could unduly favor the Benchmark options. PPA and BTA bidders are allocated significant risk which could either eliminate potential bid options or lead to much higher prices for these options if the bidder prices the risk into its bid price. We suggest that PacifiCorp either revise the contracts to create a more balanced risk profile or allow bidders to provide comments on contract issues with their proposals. For example, in response to a question from Merrimack Energy regarding contract risk allocation, PacifiCorp stated that the contracts will be subject to negotiations, apparently meaning that PacifiCorp is willing to recognize that bidders may take exception with certain provisions of the contracts. The IE has suggested that bidders be allowed to either red-line the PPA or provide comments on the Agreements with their proposals to assess if there are 'deal breaker" provisions in the contracts that will affect all or a significant portion of the bidders. PacifiCorp could then decide to make revisions to the contracts in conjunction with input from the IEs to ensure the contract provisions do not unduly bias a resource selection decision;

- The IE has also provided recommendations associated with meeting the requirements in the statute for equivalent contract terms. Section R746-420-3(8)(k) states that the solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark option, which we understand to be 30 years. The recommendation of the IE is to allow PPA bidders to offer either a 30-year term or a 20-year contract with up to a 10-year extension that is a firm price and would be exercised at the option of the buyer;

- Merrimack Energy has also recommended that the eligibility provisions in the RFP be expanded. This includes removing the requirement that only new wind projects who can quality for the full PTC benefits are eligible. Instead, the IE supports PacifiCorp's recent decision to lift the full PTC requirement and allow other bidders that may also have unique competitive advantages to compete. The IE also recommends that existing projects that are not under contract at the time of bid submission and who propose repowering their wind projects are also eligible to bid. Finally, the IE agrees with the Division of Public Utilities regarding the proposal to allow broader access to PacifiCorp's load center by eliminating the requirement in the Draft RFP that the bidder must use the proposed Aeolus to Bridger/Anticline ("Gateway Segment D2" or "D2") transmission facilities or demonstrate they can deliver the power into Wyoming. This will allow PacifiCorp to determine if its action plan for 1,270 MW of wind generation combined with construction of the transmission facilities associated with Aeolus to Bridger/Anticline transmission line are economic and provide value to customers;

- Merrimack Energy recommends that the Commission grant PacifiCorp's request for a waiver of the bid binding requirements in the Statute (Utah Admin. Code R746-420-3(10)(a). However, the IE still suggests that questions and answers will be blinded in that PacifiCorp will not know the identity of the bidder when the questions from the bidder is provided to them by the IE. Merrimack Energy will remove the name or reference to the bidder prior to submitting the question to PacifiCorp for a response;

- The IE recommends that PacifiCorp allow bidders to submit a base bid and two alternatives for the bid fee of $10,000 instead of the base bid and one alternative, particularly since PacifiCorp is encouraging PPA bidders to include a purchase option proposal with their bid. If bidders offer a purchase option presumably this will serve to use up their one allowable alternative;

- Given the importance of transmission, the IE suggests that PacifiCorp consider either providing a workshop on transmission and interconnection requirements and status of options or include a detailed discussion of these issues as part of the Bidders Conference to be held on September 12, 2017;

- The IE suggests that PacifiCorp consider revising its non-price factors to include project viability characteristics for the projects. In our view, some of the factors identified by PacifiCorp are really eligibility or threshold criteria (i.e. bids provide all required RFP information) and not non-price factors. We have identified factors such as experience of the bidder, access to generating equipment, financing plan, O&M plan, etc. as criteria to consider;

- There is little information regarding credit requirements to allow bidders to reflect the credit requirements in their bids or affect their decision to compete, unlike previous PacifiCorp RFPs. PacifiCorp could either include credit requirements based on $/kW bid or update its previous credit methodology;

- The IE recognizes the potential issues associated with new lease accounting rules and Variable Interest Entity (VIE) treatment, particularly since PacifiCorp has stated in the RFP that it will not be subject to projects that trigger VIE treatment, for example. Merrimack Energy included language in this section of the RFP to require PacifiCorp to provide documentation to the IE justifying any decision to reject a bid due to accounting issues;

- Task B3 of the IE Scope of Work as listed in the Commission's RFP for Independent Evaluator requires the IE to set up and maintain a webpage or database for information exchange between bidders/potential bidders and PacifiCorp **only if directed by the PSC in its Approval of the Solicitation Process.** Merrimack Energy proposed to establish a webpage on its website to accommodate this requirement similar to the webpages we established for previous PacifiCorp RFPs. The webpage will be used to accept questions from bidders, which Merrimack Energy staff will blind by removing the name of the bidder, before sending the questions to PacifiCorp for a response. Merrimack Energy will then review the responses and post the Question and Answer to the webpage for bidders to review. Merrimack Energy will also post any RFP documents on the webpage as well as posting any Notices to bidders of upcoming schedule items or changes to RFP documents.