ORDER NO. 07-360

ENTERED 08/20/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF	)	
OREGON	)	ORDER
	)	
Staff's Investigation Relating to Electric	)	
Utility Purchases from Qualifying Facilities.	)	

DISPOSITION: LARGE QF GUIDELINES ADOPTED;
REMAINING ISSUES RESOLVED

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I. SUMMARY

In this order, we complete our review in this docket of policies and procedures relating to the ongoing implementation of the Public Utility Regulatory Policies Act (PURPA) for Qualifying Facilities (QFs).[1] In the first phase we addressed issues relating to the development of standard contracts for utility purchases from "small" QFs. In this phase we adopt guidelines for negotiated contracts between utilities and large QFs, as well as procedures to be used when negotiations are not fruitful. We also decide several issues remaining from the first phase.

This Commission's goal is to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power (avoided costs). To further our goal of negotiated contracts for large QFs, we adopt procedures for contract negotiations. We approve the procedures and timelines specified in PacifiCorp's Schedule 38, as modified in this order, and direct other utilities to adopt similar procedures and timelines. In the event of an impasse in negotiations, we clarify the complaint procedure to be used to resolve contract issues. We decline to approve negotiated contracts in advance.

We approve a stipulation to the effect that QFs have a right to a contract term of up to twenty years. We do not preclude a longer term.

We address the distinction between "legally enforceable" and "as available" as considerations differentiating contract terms. We agree that a negotiated contract should provide incentives for reliable performance. We find that "as available" energy should be paid the prevailing non-firm market price.

[1] *See* 16 U.S.C. § 824a-3.

We adopt guidelines for applying Federal Energy Regulatory Commission (FERC) regulations requiring certain factors to be taken into account in determining avoided costs, including dispatchability and reliability. We agree that contract terms are the proper vehicle for addressing such matters as termination, scheduling of outages and availability during emergencies.

We adopt Commission Staff's proposal for calculating integration costs for intermittent resources, modified in recognition of the levels of renewable resources that must be acquired pursuant to Oregon's newly enacted Renewable Portfolio Standard.

We approve PacifiCorp's method for calculating avoided line losses for adjusting avoided costs and require its application for all types of QFs.

We adopt Staff's proposed treatment of transmission and distribution related costs and savings, while finding that transmission and distribution system upgrades should be charged separately.

We require a mechanical availability guarantee (MAG) for intermittent resources for standard contracts, in lieu of a minimum delivery obligation. We agree that a MAG can be incorporated in negotiated contracts for large QFs.

We approve a settlement for the treatment of QF surplus sales and simultaneous purchase and sale.

We decline to require the utilities to offer large QFs an energy price based on indexed gas prices.

We reject PacifiCorp's proposal that QFs larger than 100 megawatts (MW) receive no capacity payment unless they are a winning bidder in a utility RFP process.

We approve off-system standard contracts for Portland General Electric Company (PGE) and PacifiCorp, as modified by decisions in this order.

We adopt guidelines for default security for QFs that are not creditworthy.

We provide that QFs will bear the risk of their own default.

We adopt the parties' stipulation regarding the definition of "nameplate capacity."

We reject any recognition of "imputed debt" in the derivation of avoided costs.

We direct PacifiCorp to include a market pricing option in Schedule 37 and its standard contracts for small QFs. We decline to approve Idaho Power Company's (Idaho Power's) proposed Schedule 86.

We decline to require liability insurance for QFs at or less than 200 kW.

We open a rulemaking to update Division 29 rules for cogeneration and small power production facilities. As part of the rulemaking, we will promulgate rules consistent with our decision in this order on dispute resolution for negotiated QF contracts.

II. INTRODUCTION

On January 20, 2004, this Commission opened this investigation related to electric utility purchases of energy and capacity from QFs. On May 13, 2005, the Commission issued Order No. 05-584 resolving certain issues regarding continuing implementation of PURPA. We directed Oregon's electric public utilities (utilities) to file updated tariffs and standard contract forms. We further provided that a second phase of the investigation would be undertaken to address issues that required further evidentiary development (Second Phase or Phase II).

On July 12, 2005, the utilities each filed their avoided costs, revised tariffs and standard QF contracts. Based on concerns of Staff and interested parties, we ordered the utilities' filings be investigated to determine whether they complied with Order No. 05-584. The original Second Phase proceedings were held in abeyance while the Commission addressed the compliance issues. The compliance issues were decided by the Commission in Order No. 06-538, corrected by Order No. 06-586.

Following the submission of testimony in the compliance phase, the parties redirected their attention to the original Second Phase issues, now designated "Track II." Dates were set for the filing of direct and rebuttal testimony. On March 3, 2006, the Administrative Law Judge (ALJ) issued an issues list and schedule.

The parties waived cross-examination of witnesses and the ALJ canceled the hearing. The matter was submitted on the filing of opening and reply briefs. Briefs were filed by Commission Staff (Staff), Idaho Power Company (Idaho Power), Portland General Electric Company (PGE), PacifiCorp, dba Pacific Power and Light Company (PacifiCorp), Industrial Customers of Northwest Utilities/Weyerhaeuser (ICNU), and the Oregon Department of Energy (ODOE).

III. ISSUES

A. HOUSEKEEPING MATTER

In its opening brief, Staff asks the Commission to correct an apparent error in Order No. 05-584. The passage in question reads as follows:

> Although we find that firm energy provides the most reliable capacity benefits, we are persuaded by Staff's argument regarding the average availability of intermittent resources. Consequently, we conclude that intermittent and firm resources should be valued equally . . . and direct utilities to pay full avoided costs pursuant to the appropriate methodology for all energy delivered under a QF standard contract, but only up to the nameplate rating of the facility. As electric utilities cannot expect and, therefore, would not rely on deliveries of excess energy in any manner, we conclude that energy delivered in excess of the nameplate rating does not provide capacity benefits that warrant payment of full avoided costs. Because we conclude that utilities have a legal obligation to take all energy provided by a QF, we direct the utilities to accept delivery of excess energy, but to compensate QFs for only the energy itself and not capacity. In such situations, utilities should use the methodology that has historically been used when utilities are in a resource *deficient* position. (Emphasis added).

Staff believes the Commission intended the last sentence to apply when the utilities are in a resource "sufficient" position, substituting the word "sufficient" for "deficient." Staff explains that the historical method for valuing QF energy during the resource sufficiency period was through payment of off-peak rates. Citing Order No. 05-584, Staff adds that, during the period of resource sufficiency, QFs receive payment for off-peak energy deliveries based on monthly off-peak forward market prices. No party objects to Staff's proposed change.

Staff is correct. However, consistent with decisions in this order regarding pricing for "as available" energy, including energy deliveries above contract commitments, we specify that the QF should be compensated for energy deliveries in excess of its nameplate rating based on day-ahead market index prices for non-firm purchases.

Regarding the same paragraph, Staff asks that we clarify that deliveries above the QF's nameplate rating solely for the purpose of accommodating hourly scheduling in whole megawatts by a third party transmission provider do not constitute "excess energy." Again, no party objects to Staff's proposal.

We conclude that both of Staff's proposed clarifications are necessary refinements of Order No. 05-584 and will incorporate them into this decision.

B. NEGOTIATION GUIDELINES FOR NONSTANDARD CONTRACTS

1. Introduction

a. Position of Parties

As the first issue, we invited the parties to address negotiation parameters and guidelines for nonstandard QF contracts. In resolving these issues we advise the parties that any contract negotiated at arms length will be treated with substantial deference, regardless of how closely it conforms to our guidelines. We also recognize that every contract must be considered as a whole, with each term interdependent on other terms.

We note that an ALJ ruling, dated May 4, 2006, invited parties to list "guidelines for the negotiation of QF power purchases that they recommend." Only Staff and ICNU provided a list of negotiation guidelines.

PGE opposes the adoption of negotiation guidelines. PGE argues that "strictly defining parameters and guidelines for nonstandard contracts . . . in effect makes these contracts standardized, and not negotiated." PGE opening brief, 7. According to PGE, "standardizing nonstandard negotiation parameters and contract terms for large QFs is [un]necessary." *Id* at 7.

b. Discussion

We disagree with PGE. Guidelines are likely to be useful to both parties in contract negotiations. Guidelines will increase certainty and may streamline the process, to the ultimate benefit of customers.

We summarize our guidelines for negotiating large QF contracts in the Appendix. To the extent a party proposed a "guideline" that was permissive – *e.g.*, the utility "may" consider a factor, rather than a requirement that the Commission should impose a standard on the utilities – we address those recommendations in the body of the order rather than include them as a guideline.

2. Negotiation Process

a. In General

i. Position of Parties

Staff recommends as a guideline that the utility should not impose terms and conditions beyond what is standard practice for the utility's similar power transactions. Further, Staff agrees with ICNU that widely used templates, such as the Edison Electric Institute (EEI) master agreement, might serve as a foundation for negotiated QF agreements. The EEI master agreement can provide a reference point for consistency with standard practices in developing bilateral agreements for specific energy resources while taking into account unique project characteristics.

As noted by ICNU, we previously held that "the starting point for negotiation of price is standard avoided costs[.]" Order No. 05-584 at 59. ICNU argues that when a utility presents its pricing proposal to a potential QF developer, the utility should state in writing how it has modified its standard contract and standard avoided cost calculations and provide the quantitative basis for each such adjustment. According to ICNU, such a requirement would dramatically improve the transparency of the negotiating process. Staff agrees that the utility should state in writing the adjustments to avoided cost rates, but opposes a requirement to state in writing the differences between the standard contract and the negotiated contract proposal.

ii. Discussion

We acknowledge the usefulness of the EEI master agreement and other templates as a starting point in negotiating QF agreements. We find that the standard contract itself also might serve as a suitable starting point for negotiating a nonstandard contract recognizing, however, the potential size difference between a small and large QF.

We agree with ICNU's proposal that the utilities provide written quantification of their proposed departures from standard avoided cost calculations in their negotiated contract proposals. Such details should be helpful in focusing the negotiations for both sides. We agree with Staff, however, that the utilities should not be required to provide a written explanation of differences between the standard contract and negotiated contract proposal. We would expect a party to any negotiated contract to be able to explain and defend any differences between the standard contract and its proposals and final contracts, based on the negotiating guidelines we adopt in this order.

Guidelines 1 and 2(a) in the Appendix incorporate our decisions above.

b. Timeframe for Negotiations

i. Introduction

The parties offered two sets of negotiation guidelines for our consideration. First, in its compliance filing to Order No. 05-584, PacifiCorp submitted its proposed Schedule 38. As described by PacifiCorp, Schedule 38 is a "roadmap" for the negotiations between the company and a large QF developer, providing a step-by-step process that enables the company to develop avoided cost prices and a draft power purchase agreement, leading to a final agreement.

Schedule 38, Part B, sets out a process that includes the following:

1. The company's proposed generic power purchase agreement may be obtained from its website.

2. The prospective party must submit specified information to the company in order to be provided an "indicative pricing proposal."

3. After receipt of the required information, the company will provide its indicative pricing proposal "which may include other indicative terms and conditions, tailored to the individual characteristics of the proposed project" within 30 days. The company will provide a description of the methodology used to develop the prices. The prices may be modified to address specific enumerated factors.

4. The prospective QF may request in writing that the company prepare a draft power purchase agreement, to serve as the basis for negotiations. The prospective QF also must furnish additional information, as specified by the company.

5. Within 30 days of receiving the required information, the company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

6. After reviewing the draft agreement, the prospective QF may prepare written comments and proposals. The company is not obligated to begin negotiations until the written comments have been received. Thereafter the parties will conduct negotiations. The company agrees that it will not unreasonably delay negotiations and will respond in good faith to all proposals by the prospective QF.

7. When the parties have agreed, the company will prepare a final version of the contract. Contract provisions are not final and binding until the agreement has been signed by both parties.

Second, Staff offered guidelines to address timeline issues for PGE and Idaho Power. Staff's guidelines rely on the shorter timelines adopted in Order No. 06-538 for small QFs and standard contracts. Staff's guidelines also impose a duty on the utility to provide a final executable agreement to the QF within 15 business days of the parties' agreement on terms and conditions.

ii. Position of Parties

As to PacifiCorp's proposal, Staff states that it generally finds the provisions of Schedule 38 to be reasonable, with three exceptions. First, references to QF pricing options are premature, pending the outcome of this proceeding. Second, PacifiCorp should not require that interconnection studies be completed prior to providing the QF with the draft power purchase agreement. Third, as is the case with Staff's proposed guidelines, PacifiCorp's tariff should specify a timeline for providing the final agreement.

ICNU indicates that it does not have specific objections to the provisions in Schedule 38, and asks the Commission to require PGE and Idaho Power to file similar tariffs detailing the negotiation process for large QFs. ICNU notes that PacifiCorp's Schedule 38 may need to be revised to conform to this order.

In response, PacifiCorp acknowledges that its references to QF pricing options are premature. PacifiCorp agrees to Staff's comments regarding interconnection studies, provided that the QF is diligently pursuing completion of the study. It also does not oppose specifying additional timelines.

As to Staff's proposed guidelines, PGE objects on the basis that they are one-sided; that is, the prospective QFs are not required to respond in any reasonable amount of time once the final contract is provided. PGE posits "perpetual negotiations," where the utility wastes resources as it undertakes to model facilities and derive an appropriate adjusted avoided cost price offer for each unique facility.

PGE further argues that Staff's proposal does not provide enough time for utilities to process information from prospective QFs. PGE notes that the timeline is much the same as the timeline for standard contracts, while the nonstandard transaction is much more complex.

iii. Discussion

At the outset, we conclude that all three utilities should adopt the same set of negotiation timelines. Uniform timeframes will assist not only the negotiating parties, but also the Commission in resolving any claim that a party failed to meet a specified timeline during negotiations.

Of the two proposals presented, we find PacifiCorp's Schedule 38 most suitable for this purpose. We agree with PGE that negotiated contracts require more time than standard contracts, and find the shortened timelines identified in Staff's guidelines to be inadequate. Staff agrees with the timeline in PacifiCorp Schedule 38, as modified above, and does not explain why the timing in its proposed general guidelines does not correspond.

We further conclude, however, that PacifiCorp's Schedule 38 should be modified to address Staff's concerns. References to QF pricing options and the requirement of a completed interconnection study should be removed. In addition, the tariff should specify timelines for the utility to provide an executable agreement. Once the parties have agreed to contract terms, the utility should be able to provide the final agreement within 15 business days.

Finally, we find the provisions of Schedule 38 to be inadequate in terms of its provisions for resolving impasses between the parties. We adopt a process to resolve such impasses in subsection (c) below.

Accordingly, modified to fit Staff's concerns and otherwise modified to conform to this order, we find the procedures in Schedule 38 reasonable and generically adopt the provisions of PacifiCorp's Schedule 38, Part B, to prescribe the process for negotiations for all three utilities. The utilities should amend their tariffs to include corresponding schedules.

c. Negotiation Impasse

i. Positions of Parties

Our reliance on negotiated contracts for large QFs raises the question of this Commission's (and our Staff's) role in resolving disputes between utilities and prospective QFs.

Staff recommends the Commission continue its policy that restricts Staff from informal involvement in dispute resolution. Staff remains concerned that going beyond an informational role during the negotiation process would compromise its role in a formal complaint proceeding, or in rate case disputes over utility administration of QF contracts. PacifiCorp concurs.

PGE finds an informal Staff role in dispute resolution to be appropriate, noting that Staff may help resolve disputes before they become formal under the process provided under ORS 756.500.

ii. Discussion

In Order No. 05-584 (at 54) we observed that

> Pursuant to ORS 756.500, any person may file a formal complaint regarding the negotiation or enforcement of a QF contract. Unless a formal complaint is filed, the Commission does not intervene in negotiations or disputes between parties, other than to provide general information as requested.

In this decision, we clarify our intent regarding the scope of the proceeding where a complaint is filed "regarding the negotiation . . . of a QF contract."

At any time after 60 days from the date a prospective QF has provided its written comments pursuant to Paragraph 6 of the Schedule 38 type process described above, the QF may file a complaint asking the Commission to adjudicate any unresolved terms and conditions of its contract with the utility. The utility may respond to the complaint within 10 days of service. No other parties may intervene.

The Commission will limit its review to the open issues identified in the complaint or response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. *See* OAR Chapter 860, Division 016. Staff's role will be limited to advising the Commission and the ALJ. The ALJ will be acting as an administrative law judge, not as an arbitrator. The Commission will adopt rules to expedite this QF contract review. Such a process should continue to restrict Staff's role in informal dispute resolution.

We will adopt Guideline 2 in the Appendix.

d. Advance Approval

i. Position of Parties

The further issue arises whether the Commission will approve QF contracts in advance. PGE proposes that all nonstandard agreements be filed with the Commission, so that the Commission can make its own analysis and "confirm that any agreement is non-discriminatory, commercially reasonable and based on appropriate avoided costs that result in no utility and customer harm." PGE opening brief, 16.

PGE states that Commission review and approval of non-standard contracts would alleviate many of the QF concerns regarding perceived bargaining disparities. According to PGE, Commission review also would provide certainty for QFs for financing purposes and help reduce risk shifting to ratepayers.

ICNU objects to PGE's proposal. ICNU states that PGE is relitigating the Commission's conclusion in Phase I that QF contracts would not be contingent on Commission approval.

ii. Discussion

As ICNU notes, we did address this issue in Phase I of this proceeding. We stated:

> With regard to non-standard contracts, utilities have the obligation to negotiate and administer non-standard power purchase contracts with QFs that comply with federal and state mandates. The good faith fulfillment of this obligation is the best means for a utility to mitigate the risk of prudency disallowances associated with QF contracts. Indeed, we find utilities' lack of discretion regarding issues such as the location, timing, and cost effectiveness of QF power contracts favors the likelihood of a QF contract being deemed prudent. We determine that it is unnecessary and

> inappropriate to treat cost recovery of costs incurred under QF contracts any differently than cost recovery is handled for all other power purchase contracts.

Order No. 05-584, 56.

PGE has not offered any compelling reason for us to reverse our earlier holding.

3. Length of Term

a. Positions of Parties

In a partial stipulation attached to the rebuttal testimony of PacifiCorp witness Griswold, the parties agreed that QFs larger than 10 megawatts (MW) "should have the unilateral right to select a contract length of up to twenty years for a PURPA contract." The stipulation further states: "The parties have not reached agreement regarding whether the utility and QF should be permitted to enter into PURPA contracts with terms longer than 20 years." PPL/408, Griswold/15.

In its opening brief PGE states that it "has stipulated with other parties that nonstandard contracts should be limited to 20 years in length[.]" PGE opening brief, 7. Other parties dispute PGE's characterization of the stipulation.

ODOE argues that PGE's statement is overbroad: nothing in the language of the stipulation limits the contract term to twenty years. ODOE asks the Commission to clarify that adoption of the stipulation does not preclude a contract term longer than twenty years. ODOE also asks that the Commission indicate that contract length is not limited to the time that avoided costs are "known," referring to utility forecasts of future avoided costs.

ICNU argues that PGE's statement is inconsistent with the terms of the stipulation. ICNU cites the express language in the stipulation to the effect that the parties have not reached agreement regarding contract terms longer than twenty years.

b. Discussion

We cannot reconcile PGE's characterization of the stipulation with the language to the effect that the parties have not reached agreement regarding longer terms. The stipulation provides for a twenty year term. It is silent with respect to longer terms.

The QF may choose a term up to twenty years. A longer term may be reasonable and we do not preclude it.

We agree with ODOE that risks associated with longer term contracts can be mitigated by "market-based" pricing provisions. We do not reach any conclusion regarding when such provisions should first go into effect, relative to the length of the contract.

We will adopt Guideline 3 in the Appendix.

4. "Legally Enforceable Obligations" and "As Available" Differentiated

a. Legally Enforceable Obligations

i. Position of Parties

The parties recommend that firm QF contracts provide for payments based on commitment and performance. They further propose that such contracts also include provisions that make customers whole for non-performance.

Staff recommends the utility consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. Staff also states that firm QF contracts should include default and damage provisions that keep the utility and its ratepayers whole in the event the QF fails to meet its minimum net output obligation to the utility. Staff further contends the utilities should use current market prices when a firm QF chooses to receive rates based on the avoided costs at the time of delivery.

PGE argues that default and damages provisions should be included in firm QF purchase agreements, with no caps or limitations on damages. According to PGE, actual damages should be available to the utility in the event of default.

PacifiCorp states that firm deliveries should receive prices that reflect the firm nature of the resource. PacifiCorp observes that parties do not dispute that firm deliveries should be priced to include the avoided cost of capacity. PacifiCorp raises concerns regarding a market pricing option.

Idaho Power states that reliable energy and capacity provided by a QF is substantially more valuable than as available energy. Idaho Power recommends that it be allowed to negotiate contract terms that fully recognize that value.

ICNU states that firm contracts should provide incentives for reliable performance, through payments for capacity tied to performance during the peak period, with a reasonable allowance for forced outages.

ii. Discussion

There appears to be little dispute regarding the broad framework for negotiating firm contracts. We agree with Staff that the utility should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation.

We agree with ICNU that a negotiated contract for firm power should provide incentives for reliable performance. At the same time, penalties for non-performance should make customers whole. We further address these matters later in this order.

Under FERC rules, QFs that provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term can choose rates based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred.[2] The contract terms should be adapted to account for these differences.

For large QFs under a legally enforceable obligation that choose avoided costs calculated at the time of delivery, rates should be based on day-ahead on- and off-peak market index prices for firm purchases at the appropriate market hubs(s).

For QFs under a legally enforceable obligation that choose avoided costs calculated at the time of the obligation, the yearly avoided costs approved for the 20-year period for standard contracts should serve as the starting point for negotiations, as we determined in the first phase of this proceeding. Idaho Power, however, may use the modeling methodology approved by the Idaho Public Utilities Commission for deriving avoided costs that serve as the starting point for negotiations with large QFs under a legally enforceable obligation. As it agreed to do, Idaho Power must incorporate stochastic analysis of electric and natural gas prices, loads, hydro, and unplanned outages. Idaho Power must comply with all other requirements set forth in this order for negotiating PURPA contracts and avoided cost rates with large QFs.

Guidelines 2(a) and 4 in the Appendix incorporate our decisions above.

b. As Available

i. Position of Parties

Again, there is little disagreement among the parties about the broad framework. Parties agree that negotiated contracts for non-firm QFs should not include minimum delivery requirements, default damages for construction delay, for under-delivery, or early termination, or default security for these purposes.

Pursuant to FERC regulations, where the utility purchases as available energy, “the rates for such purchases shall be based on the purchasing utility's avoided

[2] *See* 18 C.F.R. §292.304(d)(2).

costs calculated at the time of delivery."[3] The parties do not agree as to the meaning of "avoided costs calculated at the time of delivery."

Staff argues that as available payments should be based on current market prices. Staff observes that utilities buy and sell energy at market prices, leaving a utility and its ratepayers indifferent to whether the QF provides the power.

PGE argues that a QF that supplies as available power should receive "energy-only" payments, "largely based on market pricing at the time of delivery." While PGE agrees that no default or damages provisions are necessary, it argues that a utility should have the right to terminate the contract and seek damages where the other party no longer qualifies as a QF.

According to PacifiCorp, prices paid to QFs should reflect the avoided cost attributable to the delivered product. PacifiCorp argues that as available deliveries should not receive a payment for capacity, but should receive the fixed, off-peak (energy only) avoided cost rate approved by the Commission. PacifiCorp claims that adoption of Staff's proposal would cause it to overpay QFs.

Idaho Power describes its current practice in Idaho, where it bases the price of non-firm energy "on published market prices." Idaho Power requests the Commission approve a similar tariff in Oregon, Schedule 86. *See* Idaho Power/302/Gale.

In its proposed guidelines, ICNU states that as-available QFs should receive capacity payments strictly on a dollar per MWh basis for deliveries during peak periods.

ii. Discussion

We adopt a market price-based approach for as available QF contracts. Specifically, as available QFs shall receive day-ahead non-firm market index rates for on-peak and off-peak energy based on the appropriate market index and market hub(s). Our decision is consistent with federal PURPA law and generally consistent with OAR 860-029-0080(4), which bases avoided cost rates for non-firm QFs on contemporary avoided costs for non-firm energy.

A market-based approach also is consistent with recommendations in this proceeding by Staff, PGE, ICNU, and Idaho Power. PacifiCorp's proposal is inconsistent with federal PURPA, which requires avoided costs for as available energy to be calculated at the time of delivery, not based on a fixed tariff rate.

Each utility must amend its tariffs consistent with the market price-based approach we adopt for as available QF deliveries. At this time, however, we decline Idaho Power's request to approve Schedule 86, which would provide an electricity

[3] *See* 18 C.F.R. §292.304(d)(1).

market index rate option for small QFs. The company's proposed 15 percent discount applied to index prices warrants further justification.

Guidelines 5 and 7 in the Appendix incorporate our decisions above.

5. Adjustments to Avoided Cost Rates

a. In General

i. Position of Parties

FERC regulations require certain factors to be taken into account, "to the extent practicable," in determining avoided costs. Those factors are enumerated at 18 CFR 292.304(e).[4]

Staff witness Schwartz testified that Staff believes the FERC enumerated a complete list, specifying all factors that may be taken into account. Further, according to Staff, "to the extent a utility foresees the need to address a particular factor in determining the appropriate avoided cost rates for negotiated QF contracts, the utility should raise that issue in this proceeding." Staff/1800, Schwartz/16.

PGE observes that each QF will have its own unique power supply characteristics. According to PGE, the value of using the FERC adjustment factors is in recognizing those unique characteristics in nonstandard contracts. PGE "strongly supports nonstandard QF contract development that considers the specific QF requirements against the backdrop of the utility's potential avoided resources." PGE opening brief, 4. PGE states that strictly defining parameters and guidelines for nonstandard contracts "in effect makes these contracts standardized, and not negotiated." PGE opening brief, 5. PGE warns of possible ratepayer harm if flexibility in negotiating contracts is lost.

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[4] (e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account: (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data; (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including: (i) The ability of the utility to dispatch the qualifying facility; (ii) The expected or demonstrated reliability of the qualifying facility; (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance; (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities; (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation; (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

Idaho Power observes that the larger QF contracts will have a significantly greater impact on a utility's operations and finances than small QF contracts and will pose a greater risk to the utility and its customers. According to Idaho Power, the utility must be allowed the freedom to negotiate terms and conditions "that fully recognize and compensate the utility and its customers for all costs incurred by the utility in conjunction with its purchases from QFs." Idaho Power opening brief, 1.

According to PacifiCorp, the FERC adjustment factors are not meant to be the "all-inclusive list" as stated by Staff. PacifiCorp states that "the overarching requirement that utilities pay avoided costs, and not more, must not be lost in an exercise of form over substance." PacifiCorp opening brief, 5. PacifiCorp argues there is no need to formulate an "all-inclusive" list of factors to be taken into account when negotiating avoided cost rates.

ICNU asks the Commission to adopt detailed and specific guidelines regarding how a utility's avoided costs can be adjusted. According to ICNU, the adoption of such specific guidelines will reduce the potential for QF/utility negotiation impasses.

ii. Discussion

We agree with Staff that the FERC rule enumerates all of the factors to be taken into account in determining avoided costs. Any utility must first seek the approval of this Commission before adjusting avoided cost rates for any factor not included in the FERC list and not approved in this order.

We adopt Guideline 8 in the Appendix.

b. Availability of Capacity or Energy

Section 304(e)(2) enumerates seven factors relating to availability to be taken into account in determining avoided costs. These include reliability, dispatchability, contract term, ability to schedule outages, usefulness during emergencies, value of the energy and capacity, and the value of the smaller capacity increments and shorter lead times associated with QF production.

Many parties treated reliability and dispatchability as one issue. We see a wide conceptual distance between the two and, therefore, address them separately, both in the body of this order and in the attached guidelines. We combine our discussion, however, on contract term, ability to schedule outages, and usefulness during emergencies.

i. Reliability

aa. Position of Parties

PGE commented sparingly on reliability and the other FERC adjustment factors. According to PGE, its method for determining an avoided cost price for a particular QF "will depend on the characteristics of the project that are related to the particular factors[.] [T]he FERC adjustment factors must be evaluated to achieve a complete deal that is non-discriminatory, commercially reasonable, and ultimately not harmful to utility customers." PGE opening brief, 11.

PacifiCorp recommends a single adjustment for both reliability and dispatchability. Specifically, the company proposes that a QF whose on-peak capacity factor during the month matches the assumed on-peak capacity factor of the utility proxy plant receive 100 percent of the capacity payment embedded in standard avoided cost rates. If the QF falls short of that "availability" in the month, PacifiCorp proposes the QF would receive no capacity payment. ICNU observes that PacifiCorp's adjustment could lower avoided cost payments for unreliable QFs, but would not increase the avoided cost payments for more reliable QFs.

Working with PacifiCorp's concept, Staff proposes the utilities develop a sliding scale model to recognize the differences in QF value based on its degree of availability – in other words, availability that falls short of or exceeds the assumed availability of the utility proxy plant. ICNU generally agrees with Staff's sliding scale concept. PacifiCorp states in its reply brief that it does not oppose Staff's approach.

Staff proposes to apply the following guidelines:

> a. Avoided cost rates should be adjusted by reducing capacity payments for the month if the QF's on peak capacity factor, or "availability," is less than the utility proxy plant.
>
> b. The QF should receive a higher capacity payment than is embedded in standard on-peak rates if the QF's on-peak performance is superior to the utility proxy plant. The adjustment for superior QF availability should be made relative to the availability of the utility proxy plant. However, the QF should not receive any additional capacity payment for availability in excess of its contract commitments.
>
> c. To address both inferior and superior availability of the QF, relative to the utility proxy plant, each utility will develop a sliding scale model to calculate adjustments to capacity payments that would apply to actual monthly QF performance during peak periods.

ICNU argues that QF contracts also should provide incentives for reliable performance through fixed dollar per kilowatt-year capacity payments (based on the fixed costs of the avoided resource) tied to performance during the utility's peak time-of-use period. Staff agrees that fixed capacity payments provide a strong incentive for reliability.

According to ICNU, incentives for performance and penalties for non-performance should be "symmetrical." ICNU proposes that capacity payments should be calculated in such a manner that the QF is paid 100 percent of the avoided capacity cost if it meets the on-peak capacity factor assumed for the avoided proxy resource.

Idaho Power requests that the company be allowed to offer a bundled dollar per megawatt-hour rate in order to avoid disputes over damages related to a fixed capacity payment. ICNU does not oppose the proposal as long as QFs that perform better than the proxy plant are rewarded with larger capacity payments.

bb. Discussion

Reliability is the ability to count on a facility to operate at predicted levels. Given that, any adjustments to rates for reliability should be made on an expected, forward-looking basis. Therefore, we do not adopt PacifiCorp's or Staff's proposal to adjust capacity payments for a QF's actual on-peak availability during the month.

We do not prescribe a specific formula for determining the reliability adjustment. We note, however, that utility power cost models are well suited to estimating the value of higher or lower reliability relative to that of the utility proxy plant. Whether QF reliability varies on a seasonal or time-of-day basis should be taken into account in determining any reliability adjustment.

We agree with Staff and ICNU that it is appropriate to provide QFs with a strong incentive to achieve the contracted level of performance. Appropriately designed, a fixed capacity payment coupled with appropriate penalties for non-performance does that, providing both an incentive for performance and a disincentive for non-performance. Idaho Power's approach, which provides all of the QF payment on a megawatt-hour basis, also provides a performance incentive and may avoid some disputes.

We will adopt Guideline 9 in the Appendix.

ii. Dispatchability

aa. Position of Parties

Staff proposes that utilities use stochastic modeling under various futures, such as that used in Integrated Resource Planning, to adjust rates to reflect the reduced value of a "24-7" natural gas-fired combined heat and power facility, relative to the dispatchable utility proxy plant. Staff proposes that such an adjustment be made only during the utility's resource deficiency period when avoided cost rates are based on a dispatchable utility proxy plant. According to Staff, the utilities could streamline the process by developing a standard avoided cost adjustment to reflect the reduced value of non-dispatchable cogeneration QFs. Regarding the size of the proxy QF the utility could use to develop the adjustment, Staff notes that PacifiCorp previously used a 50 average megawatt QF unit to estimate avoided costs for the resource sufficiency period.

In its reply brief, PGE states that adjustments to avoided costs for dispatchability should be made throughout the contract term. According to PGE, there is value to a utility from dispatchability whether or not the utility is resource deficient. PGE cites several examples of circumstances where a utility would value dispatchability in a resource sufficient situation.

PacifiCorp also objects to Staff's proposal that adjustments to avoided costs for dispatchability be made only during a utility's resource deficiency period. According to PacifiCorp, Staff fails to recognize that the cost of purchases in the market includes costs of dispatchability, such as costs for reserves and capacity. PacifiCorp claims that paying a QF market prices results in an overpayment to the QF, because the utility will incur the cost of carrying reserves for the QF. Further, PacifiCorp opposes Staff's proposed use of stochastic modeling to measure the value of dispatchability. According to PacifiCorp, stochastic modeling would be unnecessarily burdensome and time consuming.

According to Idaho Power, "dispatchability is a significant benefit to the utility and . . . non-dispatchable energy is less valuable than dispatchable energy." Idaho Power opening brief, 5. The company observes that many QFs have limited opportunity for utility dispatch compared to the utility proxy plant, which is assumed to be fully dispatchable. Idaho Power finds stochastic analysis reasonable for determining dispatchability adjustments.

ICNU objects to Staff's proposal to base the dispatchability adjustment on stochastic models. According to ICNU, the proposal would not provide any meaningful guidance to QF developers and utilities and would lead to less transparent negotiations. ICNU states that QFs would not understand the adjustments, or be able to verify their accuracy.

ICNU initially proposed that dispatchability be addressed through market-based, time-differentiated rates. In its opening brief, ICNU states that PacifiCorp's proposal for a combined adjustment for reliability and dispatchability, as adapted in Staff's sliding scale model, is a reasonable alternative.

bb. Discussion

Dispatchability is the flexibility to adjust the output of a generating resource or contract to changing market conditions. Dispatchable assets are more valuable than non-dispatchable assets, all else equal. The value of dispatchability is two-fold. First, the utility gains value from the ability to quickly increase output in periods of high market prices. Second, the utility gains value in the ability to quickly decrease output in periods of low market prices. Both sides must be considered in any dispatchability adjustment. We agree with the utilities that dispatchability has value at all times.

Dispatchability adjustments to avoided cost rates must be made on a probabilistic, forward-looking basis. The value of dispatchability must be considered on a forward-looking basis because after-the-fact calculations are likely to be influenced by whether the utility actually dispatched the QF and the amount actually gained. However, the value of dispatchability is in the utility's ability to adjust the output of the QF in response to changing market conditions, not whether the utility actually dispatches the QF. For example, even if the utility decides not to exercise its option to adjust QF output at a time when market prices are high, that option still has value.

We do not prescribe a specific method for determining the dispatchability adjustment. We believe that Staff's stochastic modeling approach is appropriate, but are open to the possibility of other less time consuming methods.

We adopt Guideline 10 in the Appendix.

iii. Contract Terms, Outages and System Emergencies

aa. Position of Parties

Among the factors FERC requires be taken into account in determining avoided costs are the terms of the contract, including the duration of the obligation, termination notice requirement and sanctions for non-compliance. We discussed above the contract term provided for by the partial stipulation we adopt. FERC rules also require the QF's ability to coordinate scheduled outages and availability during utility system emergencies to be taken into account. Staff proposes the following guidelines to address these contract terms:

> Negotiated contracts for QFs that make firm supply commitments should include default, security, termination and damage provisions that keep the utility and its ratepayers whole in the event the QF fails to meet its minimum net output obligation to the utility.
>
> Delay of commercial operation should not be a cause of termination or related damages if the utility determines at the time of contract execution that it will be resource sufficient as of the QF on-line date specified in the contract.

> Lack of natural motive force for testing to prove commercial operation should not be a cause of termination or related damages.
>
> If a QF is terminated due to its default, the utility may require the QF wishing to again sell to the company to do so subject to the terms of the original agreement until its end date.
>
> Contracts for non-firm QFs should not include minimum delivery requirements, default damages for construction delay, default damages for under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.
>
> The utility and the QF may negotiate the time periods when the firm QF may schedule outages and the advance notification requirement, using provisions in the utility's partial requirements tariffs as guidance.
>
> A firm QF should be required to make best efforts to meet its capacity obligations during utility system emergencies.
>
> A utility may negotiate scheduling requirements for deliveries from a firm QF.

Staff opening brief, Attachment A at 1, 4-5. In its reply brief, Staff observes that the guideline addressing delay of commercial operation may need to be modified to allow for damages, because of the utility's possible action in reliance on the contract.

Staff's recommendations regarding termination are the same that Staff recommended for standard contracts in the earlier compliance phase of this proceeding, with one exception: the Commission should not prescribe the time period over which the utility may seek termination damages for large QF contracts.

ICNU proposes that contract provisions should be used to address such factors, rather than an adjustment to avoided costs. ICNU states that reasonable termination provisions should be included, to keep ratepayers whole where a defaulting QF has received front-end loaded capacity payments. ICNU agrees that there are other damages a utility may incur if a QF terminates the contract. ICNU states that termination provisions should be generally the same as those in standard contracts and should be consistent with standard industry practice.

ICNU further proposes the contract obligate a QF to agree that it should schedule major maintenance outages during non-peak months, while providing the utility with reasonable advance notice of such outages. ICNU also proposes that the QF agree to make its "best effort" to fully perform during a system emergency.

bb. Discussion

We agree with ICNU that these factors should be addressed in contract provisions, rather than as adjustments to avoided costs. In particular, we agree that contract provisions for QFs under legally enforceable obligations should address default, damages and termination. Termination should be a last resort, with clearly defined benchmarks for default and for curing default. Damages provisions should reflect the underlying nature of the obligation. We reiterate our decision in Order No. 06-538 that a QF may be liable for damages for delay even in a resource sufficient situation. We also determined in that order that lack of natural motive force for testing should not be a cause for termination, but damages may be appropriate.

Guideline 4 in the Appendix incorporates our decisions above.

iv. Individual/Aggregate Value and Smaller Capacity Increments/Shorter Lead Time

FERC rules specify that, "to the extent practicable," the individual and aggregate value of energy and capacity from QFs, and the relatively small capacity increments and short lead tines for QFs, are factors to be taken into account in determining avoided costs. No party put forth a definitive method for incorporating these factors. Therefore, we do not require a specific adjustment or formula for adjusting avoided costs for these factors. However, parties should incorporate these factors into the negotiated contract if they can establish a practical and reasonable way to do so.

c. Ability of Utility to Avoid Costs – Fossil Fuel Use Reduction

i. Position of Parties

For large renewable resource QFs not receiving market-based pricing, Staff recommends the Commission adopt an adjustment to avoided costs, applicable during the resource deficiency period, to reflect the utility's avoided natural gas price risk, compared to the utility's natural gas-fired proxy plant. Staff contends that such an adjustment is necessary to achieve a level playing field for QF contracts, compared to acquisition of utility-owned resources or contracts acquired through competitive bidding. Staff notes the utilities' resource planning and acquisition processes address both cost and risk, including fossil fuel price risk.

ICNU maintains that if the Commission adopts such an adjustment, it also should apply to combined heat and power (CHP), or cogeneration, facilities that demonstrate they can use natural gas more efficiently than the utility proxy plant. In support of its proposal, ICNU cites a 2005 study by the Lawrence Berkeley National Laboratory that estimates the relative benefits of CHP facilities and renewable resources in reducing natural gas prices. Staff ultimately agrees with ICNU that avoided costs should be adjusted to account for the reduced fossil fuel use of CHP facilities, to the extent the QF is not receiving market-based pricing.

PacifiCorp finds Staff's proposal flawed because it is based on two assumptions the company asserts are false: 1) the natural gas prices used to develop standard avoided cost rates do not reflect price risk and 2) the utility does not protect itself with risk management and hedging programs. The company finds ICNU's proposal flawed because it would pay the cogeneration QF the value of reducing the regional price of natural gas (the presumed result of the QF's superior efficiency), the value of which would be reflected in the price of gas for the utility proxy plant that would be avoided. Further, the QF would receive the value of the presumed reduction in natural gas price again through operation of the gas-fired cogeneration plant.

ii. Discussion

FERC rules specify that the ability to avoid costs through a reduction in fossil fuel use be taken into account in determining avoided costs. We adopt Staff's proposal, which seeks parity between acquisition of renewable resources through negotiated QF contracts and acquisition of renewable resources through utility resource planning and acquisition processes that account for both cost and risk. The renewable resource QF contributes toward the direct reduction of the utility's risk for fossil fuel costs related to the fossil fuel proxy resource.

We adopt a similar provision for natural gas cogeneration QFs when under a fixed pricing contract, but not for the reasons put forth by ICNU. ICNU's argument is based on a theoretical and indirect impact to the utility and its ratepayers, relying on the ability of one or several CHP facilities to influence the regional natural gas market and, in turn, reduce electricity market prices. We will require the utilities to adjust avoided costs for gas-fired cogeneration QFs — if they choose avoided costs calculated at the time of the obligation — because the fixed-price nature of the contract mitigates the utility's fuel cost volatility, compared to the utility's proxy fossil-fuel plant.

We do not prescribe a specific method for determining the adjustment for fixed-price, negotiated contracts to recognize the benefit of reduced fuel cost volatility, compared to the natural gas-fired utility proxy plant. We believe a stochastic modeling approach similar to the method used in power cost dockets is appropriate, but other methods may be reasonable.

We adopt Guideline 11 in the Appendix.

d. Integration of Intermittent Resources

i. Position of Parties

"Integration" refers to the process of accommodating the variable output of intermittent resources, such as wind, as part of the utility's portfolio. Integration includes regulation – using automatic generation control to control system voltage, load following – ramping dispatchable generators up and down, and altering unit commitment on an hourly or longer basis.

For small wind projects under standard contracts, Staff maintains that the method for calculating standard avoided costs adopted in Order No. 05-584 is a reasonable estimate of the costs the utility will avoid by purchasing from the small QF, and standard avoided costs should not be adjusted for integration costs. Staff notes that avoided cost rates for standard contracts are not adjusted for any costs or benefits of the QF project, relative to the utility proxy plant.

For large wind projects, Staff recommends that avoided cost rates be adjusted for integration costs, based on studies conducted for each company's system. Staff argues that consideration of such costs "fits" the FERC adjustment factor, "The individual and aggregate value of energy and capacity supplied from qualifying facilities on the electric utility's system."

Staff states that integration costs increase significantly as the level of intermittent resources increases. Staff notes that standard ratemaking practice uses only known and measurable loads and resources when setting cost-of-service rates. Staff does not recommend this approach for determining the level of intermittent resources that serves as the basis for integration costs because the utilities' acknowledged Integrated Resource Plans indicate they may acquire sizable levels of wind resources in the future. Staff therefore recommends that the Commission require a utility to base first-year integration costs on the actual level of wind resources in its control area, plus the proposed project. For years two through five, Staff proposes that integration costs be based on the anticipated level of wind resources in the control area in each year, including planned new resources. Staff recommends that integration costs be capped at the year-five level for the remaining life of the project. Staff notes that projections beyond five years are highly unreliable.

In its opening brief, Staff explains that it is not recommending a "project specific" approach, as initially understood by PacifiCorp. Staff recommends that the Commission not allow the utilities to use a long-term planning target as the basis for determining integration costs for a large QF project. Instead, the utilities should base integration costs on the actual amount of wind and other intermittent renewable resources within the control area "today," plus the amount of these resources the utility expects to acquire through its resource planning and acquisition processes over the next five years.

Staff offers three additional considerations regarding estimates for integration costs for large wind QFs. First, if the QF chooses to contract for integration services with a third party, the utility should make no downward adjustment in avoided cost payments for integration costs. Second, the utility should use the most recent integration cost data available, consistent with its evaluation of competitive bid and self-build wind resources. Third, analysis of incremental reserve costs associated with integrating intermittent resources should be based on the difference between reserve costs for the wind project and the proxy plant, not the reserve costs for the wind project itself.

PGE states that integration costs for intermittent resources is an emerging issue likely to be addressed in its next Integrated Resource Planning process. PGE agrees that such costs can be addressed through a flexible application of the FERC adjustment factors. According to PGE, for large QF projects where integration costs may be significant, impacts over the life of the contract must be considered. PGE argues that Staff's proposal does not align with prudent future planning.

PacifiCorp states that it does not oppose Staff's proposed approach conceptually, but first argued that the preciseness that would be gained does not warrant the significant time commitment and expense that would be incurred in performing individual modeling analyses for each project. Based on Staff's clarification of its position in its opening brief, PacifiCorp states that it does not oppose Staff's proposed method for addressing integration costs.

ii. Discussion

We agree with Staff's approach. Five years represents an outer boundary for such an analysis. However, we take note of the recent adoption of a Renewable Portfolio Standard for Oregon that sets mandatory renewable resource acquisition levels through 2025, with interim targets for PGE and PacifiCorp in 2011, 2015, and 2020. If a utility is subject to near-term targets under a mandatory Renewable Portfolio Standard, the utility may base its integration costs on the levels of renewable resources it must acquire over the next ten years. As we do not expect all of these new renewable resources to be wind or other intermittent resources, the utility should not assume that all of the renewable resources it will acquire will require integration services.

We adopt Guideline 12 in the Appendix.

e. Line Losses

i. Position of Parties

Staff observes that, if QFs are located at or near customer sites, line losses and other transmission and distribution costs may be lower than for the utility proxy plant, which typically is located in a remote location. To address this, PacifiCorp proposes a proximity-based approach to be applied on a case-by-case basis. PacifiCorp contends this approach is standard in the industry, and explains that an adjustment to avoided cost prices, either as an increase or a decrease, is based on costs or savings resulting from a QF delivering power to a load area, in lieu of power that the utility would have supplied to that same area (either generated or purchased). Line loss adjustments would not be made for QFs with unpredictable output, such as wind projects.

ICNU cites the PacifiCorp proposal as a "good starting point" for developing a line loss methodology applicable to each of the utilities. ICNU states that it would support PacifiCorp's proposal if it were clarified to indicate that the load area intended is the load area closest to the QF, not the load area closest to the proxy plant.

Staff finds PacifiCorp's proposed treatment of line losses to be reasonable. In its reply brief, however, Staff agrees with ICNU that PacifiCorp's proposal should be clarified to state that it refers to the load area that the QF generation would actually serve, not the load area that the proxy plant would serve. Otherwise, Staff contends, the adjustment would be punitive in nature.

ii. Discussion

In its reply brief PacifiCorp provides the clarification sought by Staff and ICNU. We adopt PacifiCorp's proposal, as clarified, for each of the utilities. However, we do not find PacifiCorp's distinction between predictable and unpredictable QFs persuasive. A line loss adjustment should be estimated for all non-standard QF projects.

We adopt Guideline 13 in the Appendix.

f. Transmission/Distribution Costs

i. Position of Parties

Staff offers two guidelines that address avoided cost treatment of transmission and distribution system costs:

> Transmission and distribution (T&D) system upgrades that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant should be eligible for an additional avoided cost payment. The utility may require load shedding by the QF host in the case of a QF outage during certain peak hours. Any analysis of potential T&D system savings should include projected load growth and associated T&D needs.
>
> Any necessary transmission upgrades to accept QF power should be separately charged as part of the interconnection process and should not affect avoided cost rates. However, if during low load hours the utility backs down more economic generating resources instead of upgrading the transmission system to move the QF power outside of a load-constrained area, avoided cost rates should be adjusted to account for the higher cost of non-dispatchable QF power.

Staff interprets the FERC regulations to allow T&D cost implications to be considered as relating to the "value" of QF power.

ICNU states that transmission and distribution related costs and savings should be accounted for in the negotiations. ICNU agrees with Staff that transmission upgrades should be charged separately as part of the interconnection process, and not included in the avoided cost. ICNU argues that QFs should not be responsible for paying incremental costs of transmission upgrades that benefit the larger transmission system.

ICNU agrees with Staff that T&D costs that can be avoided or deferred as a result of the QF's location should be recognized in an adjustment to avoided costs. ICNU objects to any lower limit on the size of the QFs that might qualify for including avoided T&D costs in their avoided cost payments under negotiated contracts.

ii. Discussion

We agree with Staff and ICNU that avoided T&D costs should be taken into account in determining avoided costs, and that transmission upgrades should be separately charged as part of the interconnection process, not included in avoided costs. We reject any lower limit on the size of QFs that might qualify for including avoided T&D costs in their avoided cost payments under negotiated contracts. Regarding Staff's recommendation that avoided costs be adjusted if parties agree the utility will back down other resources in lieu of wheeling QF power outside a load-constrained area, any such adjustment may be taken into account in valuing QF dispatchability.

We adopt Guidelines 14 and 15 in the Appendix.

g. Debt Imputation

i. Position of Parties

"Debt imputation" refers to the treatment of power purchase agreements as "debt like" obligations by rating agencies. According to PacifiCorp, the debt imputation issue has come to the forefront in recent years, citing the issuance of two financial reporting standards that allegedly require that it recognize certain power purchase agreements as capital lease obligations, which are considered as debt.

PacifiCorp claims that the impact of this treatment is quite straightforward: the imputed debt reduces the amount of debt a utility might otherwise issue while maintaining a particular debt/equity ratio. According to PacifiCorp, an increase in equity is required to offset the impact of the imputed debt on its capital structure, imposing additional costs on the utility and its customers. PacifiCorp calculates that additional cost as the difference between the pre-tax cost of equity and the pre-tax weighted average cost of capital, times the amount of equity needed to rebalance the capital structure.

PacifiCorp maintains that the debt calculations should be done on an agreement by agreement basis, with the implicit debt cost addressed separately from the avoided cost price. The debt cost would then be included in the power purchase agreement as a monthly line-item adjustment to the QF payment, rather than embedded in avoided cost prices.

PGE states that debt imputation is a minor issue at current QF activity levels. However, it states that the potential cumulative and long-term effects of debt imputation may be significant, and suggests the Commission should be aware of the potential impact as an issue with respect to the determination of avoided costs.

Staff argues that debt imputation should not be included in the avoided cost calculations. Staff cites two reasons for its recommendation: (1) there is no reliable method to quantify the alleged impact of a power purchase agreement on a utility's cost of equity; and (2) if such an impact can be shown, the proper place to account for it is in the utility's next rate case.

Staff observes that a utility may have many power purchase agreements, with varying maturities and contract terms. Staff argues that there are many variables that impact a utility's risk, such that the quantification of the impact of these agreements on a utility's cost of equity necessarily requires a comprehensive analysis of the many costs, risks and benefits that comprise a utility's capital structure.

ICNU also argues that debt imputation should not be used to adjust avoided costs. ICNU observes that the utilities did not identify this cost in their avoided cost filings. According to ICNU, it has been raised now as an arbitrary and unnecessary barrier to QF development.

ICNU claims there is no evidence that QF contracts require an adjustment for debt imputation. ICNU states that a utility's cost of capital is based on numerous factors and that it is difficult to ascribe to any particular factor an impact on the cost of capital.

In any event, ICNU argues that PacifiCorp's argument does not apply to most, if any, large cogenerator QFs, based on PacifiCorp's own testimony. For a contract to be treated as debt, the standards require that certain conditions be met, including the utility's right to operate or control the plant, and the prospect for sales to other purchasers of more than 10 percent of the plant's output. ICNU claims that these conditions are not likely to occur in typical QF contracts with large cogenerators.

ii. Discussion

We agree with Staff and ICNU that imputed debt associated with QF power purchase agreements should not be taken into account in determining avoided costs. Given the preconditions for debt imputation as stated by PacifiCorp, we find that it is not likely to be caused by large QF contracts in any event.

We adopt Guideline 16 in the Appendix.

6. Creditworthiness and Default Security

a. Position of Parties

For QFs that are not able to establish creditworthiness, Staff proposes the Commission mandate the same default security requirements that it recommended for QFs eligible for a standard contract. These requirements, to be selected at the QF's option, are senior lien, step-in rights, a cash escrow or a line of credit.

Staff incorporates its views into two guidelines, the first one of which was previously addressed on page 20 of this order:

> Negotiated contracts for QFs that make firm supply commitments should include default, security, termination and damage provisions that keep the utility and its ratepayers whole in the event the QF fails to meet its minimum net output obligation to the utility.
>
> QFs unable to establish creditworthiness must provide security with terms comparable to provisions in PGE's or PacifiCorp's standard QF contracts. Utilities should take into account the risk associated with the QF based on such factors as its size and the type of supply commitments the QF is making.

Staff also states that the default security provisions for large QFs should not be more onerous than for the company's non-PURPA agreements for similar types of transactions.

PGE states "there should be no arbitrary limitations on creditworthiness assurances." PGE opening brief, 11. PGE observes that, the larger the QF facility, the greater potential impact on a utility's resource planning and customer rates caused by QF default. According to PGE, appropriate and commercially reasonable amounts of default security should be available to cover the risk of default for a large QF.

PGE opposes Staff's recommendation that large QFs would have the choice to elect a senior lien or step-in rights. PGE states that the security options available to a utility and a large QF should be comparable to the forms of commercially reasonable security that are used in other large power supply market transactions.

PacifiCorp also argues that the senior lien and step-in rights offered to smaller QFs should not be mandatory for larger QFs. PacifiCorp states that neither method is likely to provide assurance to the utility that it would provide adequate coverage for the QF's default.

According to PacifiCorp, establishing an appropriate level of default security is necessary to protect a utility and its customers from the risk of default by a non-creditworthy counterparty to a power purchase agreement. For large QFs, PacifiCorp proposes to cap the amount of required default security at thirty-six average months of replacement power. PacifiCorp states that the time period is based on the amount of time expected to replace the large QF with forward market purchases. Staff does not object to PacifiCorp's proposed cap.

b. Discussion

We agree that senior lien and step-in right options should not be mandatory for large QFs. At a minimum, QFs unable to establish creditworthiness must be able to choose either a letter of credit or cash escrow for providing default security.

PacifiCorp's proposed thirty-six month cap recognizes the greater risk associated with a QF that may be several hundred megawatts, compared to the 12-month cap for standard contracts available to QFs up to 10 MW. We agree with Staff that in deciding the number of months to use in a particular case, the utility should take into account such factors as QF size and type of supply commitments. As such, default security methodologies specified in PGE's and PacifiCorp's standard QF contracts are a useful starting point for negotiations with large QFs.

We also agree with Staff that the default security provisions for large QFs should not be more onerous than for the company's non-PURPA agreements for similar types of transactions. The companies will be expected to defend their security demands by comparison to similar provisions in non-PURPA contracts. As such, we do not adopt a specific cap.

Guidelines 4(c) and 6 in the Appendix reflect our decisions above.

7. Default Losses

a. Position of Parties

Staff recommends that the Commission not impose a limit, or cap, on the default losses that may be recouped from a large QF. Staff argues that its recommendation is reasonable because of the potential risks associated with a large QF's default and because a large QF generally has greater financing flexibility than a small QF. Staff notes that adoption of its proposal would provide a (negative) incentive to keep a large QF from abandoning its project.

PGE states that mandated damage caps do not allow a utility to recover actual damages caused by a QF default. PGE argues that such caps expose utilities and customers to risks of QF non-performance that should be borne by the QFs themselves.

PacifiCorp argues that no cap should be imposed. According to PacifiCorp, by not capping losses, a QF will be discouraged from abandoning a project, thereby helping to ensure greater reliability and protecting customers from higher costs.

b. Discussion

We agree that larger QFs should bear the risk of their own default. We do not adopt a cap on default losses. Guideline 4(c) in the Appendix addresses this issue.

8. Surplus Sale or Simultaneous Purchase and Sale

a. Position of Parties

"Surplus sale" refers to a QF's sale of its net generation output minus the QF host's on-site electricity requirements. "Simultaneous purchase and sale" assumes that the QF sells to the utility its entire net output, while simultaneously purchasing from the utility its full electrical requirements at tariff rates. One's reasonable expectation is that the QF would plan to sell its full output to the utility when the avoided cost price is greater than the retail rate, while selling only its surplus energy to the utility when the avoided cost price is lower than the retail rate and serving its on-site requirements with its own generation.

The parties state that they have settled issues relating to these matters. The terms of the settlement are as follows:

> For purposes of this resolution, "surplus sale" is defined as the QF's sale to the purchasing utility of the net output of the QF generation minus the QF host's on-site electricity requirements. "Simultaneous purchase and sale" means the QF's sale to the purchasing utility of the net output of the QF generation and the purchase of the QF host's on-site electricity requirements from the purchasing utility under that utility's applicable retail sales tariff (*see* Order No. 05-584, p. 53). Under a "simultaneous purchase and sale" the QF and the purchasing utility enter into two separate transactions. Nothing in this settlement agreement limits the ability of a QF to sell any electricity at wholesale to third parties.
>
> (1) QFs may either contract with the purchasing utility for a "surplus sale" or for a "simultaneous purchase and sale;" provided however, that the QF's selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the purchasing utility then in effect or any agreement between the QF and the purchasing utility;
>
> (2) The two sale/purchase arrangements described in paragraph (1) will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the "simultaneous purchase and sale" is not available to

> QFs not directly connected to the purchasing utility's electrical system;
>
> (3) The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph (1); and
>
> (4) The avoided cost calculations by the utilities do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph (1), rather than the other.

PPL/408, Griswold/11. The parties request that the Commission approve the settlement.

b. Discussion

We find the parties' settlement to be a reasonable resolution of these issues. The stipulation is approved and included as Guideline 17 in the Appendix.

C. MECHANICAL AVAILABILITY GUARANTEE

1. Position of Parties

A mechanical availability guarantee (MAG) measures the performance of a plant against itself, not against an external standard. "Mechanical availability" for a wind plant refers to the percentage of time that a facility produces net output energy, compared to the total amount of time that the facility could have produced net output energy, had all turbines been fully operational. Inadequate or excessive wind, force majeure and scheduled maintenance are examples of events that are deducted from the amount of time that the facility could have produced energy.

According to Staff, avoided cost prices are not affected by the MAG. A MAG only affects payments to the QF to the extent it does not meet its contractual commitment under the MAG. Staff argues that such a performance standard would reinforce the Commission's previous order that intermittent (wind and run-of-river hydro) and non-intermittent resources should be valued equally, and that intermittent resources should receive full avoided costs for deliveries under a standard contract.

Staff recommends the Commission require the utilities to include a MAG in standard PURPA contracts for firm supply commitments. Staff argues that contracts for non-firm supply commitments should not include a MAG.

For non-standard PURPA contracts, Staff recommends the utility and QF negotiate whether to incorporate a MAG or a minimum delivery obligation. Staff notes that both PacifiCorp and PGE have agreed to MAGs in non-PURPA negotiated wind contracts.

PacifiCorp proposes that the MAG be used as a performance standard, in place of a minimum delivery obligation, for all intermittent QF projects, regardless of size. According to PacifiCorp, a MAG operates so as to affect the payment to a QF to the extent the QF does not meet its contractual availability commitment; it does not affect the calculation of avoided cost prices.

PacifiCorp states that its MAG appropriately recognizes that a wind or run-of-river QF cannot accurately forecast generation output months in advance. The MAG measures the QF's performance by what it can control – the mechanical availability of its turbines.

PacifiCorp proposes that the Commission allow a utility to include a MAG in its standard contracts for small intermittent QFs. For large QFs, PacifiCorp argues the Commission should recognize that particular levels of availability guarantees under MAGs will be established by contracting parties on a case-by-case basis, taking into account the attendant conditions and characteristics.

Idaho Power states that it does not object to including a MAG in any agreement, however, it does not believe that a MAG should be included in lieu of minimum delivery obligations. Idaho Power argues that a MAG, when used in conjunction with standard minimum delivery requirements, can give the utility some additional comfort that the QF will do everything in its power to meet minimum delivery obligations. According to Idaho Power, if a MAG is used in lieu of a minimum delivery requirement, then a portion of the risk of investing in an intermittent resource will be shifted from the QF developer to the utility and its customers.

PGE states that a MAG may be useful in providing more certainty to a utility and its customers that a particular facility will have the capability to generate. However, according to PGE, a MAG does not guarantee delivery (despite inherent incentives for a QF to generate, with or without a MAG). Therefore, PGE argues, a QF with only a MAG should not receive the same firm avoided cost pricing as a QF that negotiates a minimum supply commitment.

Staff disagrees with PGE. Staff states that the delivery commitment under a MAG is based on fixed percentages of the QF's full output when wind or water are available, except for excused events. Staff observes that the current standard contracts base the QF's minimum delivery obligation on the output predicted under worst-case motive-force conditions. A MAG gives the QF an additional incentive to maximize availability and avoids disputes over determination of the QF's minimum delivery obligation.

2. Discussion

We adopt Staff's position that a MAG should be included in all standard contracts for intermittent resources, in lieu of a minimum delivery obligation. We find that a MAG fairly balances the ratepayer and QF interest in maximizing QF production while recognizing the limitations of intermittent resources.

We disagree with Idaho Power that a minimum delivery obligation is needed to assure the utility of reliability. A minimum delivery obligation does not improve the reliability for the utility, it only increases the risk for the QF.

For large QFs, we agree that a MAG can be incorporated into a negotiated contract. We note that both PGE and PacifiCorp apparently have negotiated MAGs in non-PURPA wind contracts.

We agree that a MAG does not affect the calculation of avoided costs. It operates so as to affect the dollar payment to the QF, to the extent the QF does not meet its contractual availability commitment.

D. GAS INDEX PRICING OPTIONS

1. Position of Parties

ICNU argues that large QFs should have the same pricing options offered to small QFs: 1) the Fixed Price Method; 2) the Deadband Method; and 3) the Gas Market Method. Specifically, ICNU argues that large QFs should be allowed to choose a natural gas price indexing method, allowing the QFs to avoid relying on the utilities' natural gas forecasts, thereby reducing their risk.

ICNU argues that the gas index options should be available to all QFs, if the utility's proxy resource is a gas-fired plant. According to ICNU, PacifiCorp and PGE have sophisticated risk management and hedging programs for managing gas price risks. ICNU states that the utilities could mitigate the risk of gas-indexed QF contracts and be neutral as to whether the utility builds its proxy resource or enters into QF contracts. ICNU notes that the costs the utility avoids are the same for large QFs as for small QFs.

ICNU notes that the avoided cost filings of the utilities include gas price forecasts. According to ICNU, the only thing certain about these forecasts is that they will be wrong. ICNU states that the inaccurate gas price forecasts can result in inaccurate price signals to QF developers: if the forecast is low, it will be very difficult for gas fired QFs to sign contracts; if the forecasts are too high, then ratepayers will be harmed by excess payments to QFs. ICNU argues that this problem can be avoided by providing large QFs with an option to index the gas component of the avoided cost rate to a gas index.

Staff argues that the Commission should not require the utilities to offer large QFs the same pricing options made available to small QFs. Staff explains that its recommendation would allow the utility to object to gas index pricing options if they could be harmful to the utility and its ratepayers. Staff recommends the Commission not preclude the utilities from offering such options during their negotiations with large QFs.

Staff also notes that a utility's avoided resource may change over time. If the avoided resource during the deficiency period is coal or wind, a rate option indexed to natural gas prices would be inappropriate. As such, it may be appropriate in a future avoided cost filing for the utility to forgo offering the gas index options to small QFs.

PGE states that ICNU's recommendation reveals ICNU's intent that QFs should not bear their own fuel price risk. According to PGE, large sophisticated companies should be willing to hedge that risk themselves. PGE argues that ICNU is asking for a tolling arrangement with an "unlimited put." PGE suggests that arrangement should be considered in the context of a request for proposals as part of resource planning.

PacifiCorp argues that adoption of ICNU's proposal would expose PacifiCorp to significant risk due to wide fluctuations in gas market prices. PacifiCorp states that it does not have a mechanism that allows it to flow through such costs to its customers. PacifiCorp argues that the resulting imposition of risk on shareholders would be contrary to the Energy Policy Act of 2005.

PacifiCorp further argues that adoption of an indexed gas price option for large QFs would be contrary to the PURPA ratepayer neutrality standard – it would require payments to QFs in excess of the company's avoided costs. According to PacifiCorp, the concept assumes that the utility otherwise would be exposed to gas market price fluctuations. PacifiCorp states that it employs risk management and hedging programs to manage its gas price risk. Thus, PacifiCorp concludes that payments to QFs based on indexed gas prices would disregard PacifiCorp's risk management and hedging programs.

Idaho Power states that it does not have a base-load natural gas-fired generating resource in its resource portfolio. According to Idaho Power, its decision not to include such a resource reflects its concerns with the volatility of natural gas prices.

Idaho Power further argues that a natural gas price index option for large QFs would impose an undue risk on its customers. Idaho Power cites an instance where a QF developer proposed to build a large QF at an industrial facility in Idaho Power's Oregon service territory, using the gas price methodology in the standard contract. Idaho Power states that it calculated a substantial increase in its cost of service if the contract were to be executed.

2. Discussion

We agree with Staff and the utilities that the utilities should not be required to offer large QFs the same pricing options made available to small QFs. Utilities are not precluded from offering such options during their negotiations.

E. ROLE OF COMPETITIVE BIDDING

1. Position of Parties

PacifiCorp proposes that the terms, conditions and price for capacity purchases from QFs that are 100 MW or larger, with contract terms of at least five years, be determined through an all source competitive bidding process. PacifiCorp also proposes that offers of QF capacity made outside of the bidding process, or by QFs that are not selected through the competitive bidding process, would not receive capacity payments, at least during the resource sufficiency period. Such QFs would receive payment for energy only.

According to PacifiCorp, the use of competitive bidding would provide the Commission and all parties with the best available determination of avoided costs. PacifiCorp argues that failure to require that QFs can obtain capacity payments only through a bidding process would diminish the effectiveness of the process. PacifiCorp argues that using competitive bidding to determine avoided costs and receive capacity payments is appropriate under PURPA and has been sanctioned by FERC.

PGE states that, while a request for proposals (RFP) process may be useful in determining an appropriate price, it should not be used in all circumstances, because avoided cost information may be available as a reasonable proxy. PGE observes that timely information about resource costs would be useful in developing avoided cost prices.

According to Idaho Power, while it does not take the position that QFs should be required to participate in competitive bidding, it does believe that results of competitive bidding for similar resources must be considered in setting avoided cost prices. Idaho Power indicates that it has issued RFPs for wind and geothermal resources and expects to have current market price information to compare with administratively determined costs.

Staff agrees that competitive bidding could be used to set prices for QFs larger than 100 MW during a resource deficiency period. Staff states that it does raise issues relating to time, the type of RFP that would be used, which winning bid to use as the basis for negotiations, and having different avoided cost methodologies for large and very large QFs.

Staff argues that competitive bidding should not be used to determine avoided costs during a resource sufficiency period. Staff points out the Commission's decision in the prior phase of this proceeding that the on- and off-peak forward market prices in the utility's approved avoided cost filing are the starting point for negotiating avoided costs during the resource sufficiency period.

Staff opposes PacifiCorp's proposal to provide no capacity payments to QFs larger than 100 MW, unless selected by the utility through the RFP process.

According to Staff, the company will be resource-deficient at some point over the contract term and will need capacity resources beyond those acquired in the RFP process.

Staff states that results from competitive bidding may be useful in updating a utility's avoided costs, and utilities are free to make such a filing following a competitive bidding process.

ICNU argues that requiring a QF to participate in competitive bidding is inconsistent with the utilities' obligation under PURPA to purchase any energy and capacity that is made available at avoided cost. According to ICNU, the bidding process is rarely a realistic option for QFs because utility bidding requirements are typically inconsistent with the QF's operational characteristics, which may be powered by intermittent resources or associated with industrial processes that have specific operating requirements.

ICNU asserts that Staff proposed a process by which avoided costs for very large QFs would be set based on the results of winning competitive bids. According to ICNU, Staff's proposal is complex and raises numerous issues. If the Commission intends to allow utilities to use the results of the competitive bid process, ICNU suggests that they incorporate the information into their next avoided cost filings.

2. Discussion

We do not adopt PacifiCorp's proposal to require QFs 100 MW or larger to participate in the utility's RFP process and provide a capacity payment only if the QF is a winning bidder. We find the proposal inconsistent with federal PURPA law, which requires the utility to purchase any energy and capacity that is made available from a QF. *See* 18 C.F.R. § 292.303(a). Further, we do not adopt a methodology that uses competitive bidding results directly to determine avoided cost rates. Staff and ICNU raise numerous issues about the complexity of doing so, compared to the methodologies we adopted in the first phase of this proceeding. As Staff and ICNU note, a utility may use the information it acquires through a competitive bidding process when it next updates its avoided costs. Guideline 4 incorporates our decision.

F. STANDARD OFF-SYSTEM CONTRACTS FOR PGE AND PACIFICORP

1. Position of Parties

The parties resolved all but one issue relating to off-system contracts for PGE and PacifiCorp. The disputed issue is whether the utility should pay the off-system QF for energy in excess of its net output not offset during the settlement period.
Staff recommends the QF be compensated for the excess energy at the non-firm, off-peak spot price, reflecting the market value at the time of delivery. PacifiCorp disagrees with Staff's recommendation for two reasons. First, the company states that PURPA requires a utility to purchase only the net output of the QF. Second, the company contends that

Staff's proposal would eliminate the QF's incentive to accurately schedule energy deliveries across the settlement period.

2. Discussion

> The PGE and PacifiCorp off-system standard contracts are approved, as modified by this order. Regarding energy in excess of net output that is not offset during the settlement period, we recognize that the utilities have no obligation to purchase that energy under PURPA. The parties may negotiate the price that would apply to any such sales.

G. NAMEPLATE CAPACITY

The parties addressed alternatives to using nameplate capacity for determining the size of a QF project eligible for standard avoided cost rates and standard contracts, including a clear definition of nameplate capacity if that is retained as the basis for eligibility. The parties agreed to the following definition of "nameplate capacity":

> The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

We adopt the stipulation.

H. MARKET INDEX PRICING OPTION FOR PACIFICORP

1. Position of Parties

Staff notes that the Commission did not direct PacifiCorp to offer a market-indexed pricing option for the earlier phase addressing standard contracts. In Order No. 05-584, however, we advised parties that it may be appropriate to further consider market pricing options in this phase of this proceeding. We specifically directed PacifiCorp to work with Staff to evaluate whether it would be appropriate to develop an indexed pricing option and encouraged the company or Staff to bring forward such an option in this phase of the proceeding. *See* Order No. 05-584 at 35.

Staff observes that PacifiCorp, PGE, and Idaho Power have two Commission approved market pricing options for small QFs based on natural gas prices — the Gas Market and Deadband options. Staff also notes PGE's third market option for small QFs, based on daily Mid-Columbia (Mid-C) electricity prices.

According to Staff, such market-based rates benefit not only the utility and its ratepayers, they also benefit QFs that prefer to make a minimal supply commitment, as well as those able to reduce on-site load to make additional sales to the utility when market prices are high.

ICNU supports a market pricing option for PacifiCorp that would be similar to the Mid-C market option now offered by PGE. According to ICNU, such a rate would provide QFs more options to meet their operational needs, without imposing additional risks upon PacifiCorp.

PacifiCorp argues that a market pricing option would increase its risk of excessive cost exposure due to fluctuations in market prices that could not be recovered in rates under the regulatory mechanism currently in place. According to PacifiCorp, a rate indexed to electric market prices would be contrary to the ratepayer neutrality standard, in that it disregards the risk management and hedging activity used to mitigate the risk of market price fluctuations.

2. Discussion

We adopt Staff's position that PacifiCorp offer a market index pricing option. We previously found PGE's proposal to add a Mid-C market pricing option for small QFs to be reasonable. Our action also is consistent with our decisions in this order regarding pricing for as available QFs.

I. LIABILITY INSURANCE

1. Position of Parties

An issue revisited from an earlier phase of the proceeding is whether utilities should be able to mandate liability insurance coverage for QFs at or under 200 kW. Staff argues that liability insurance should not be mandatory for such QFs.

Staff observes that ORS 757.300(4)(c) prohibits utilities from requiring net metering facilities to purchase liability insurance.[5] Staff offers an analogy between a net metered producer and a small QF, where the QF's operating expense could be considerably higher, because of the insurance costs. Staff warns the added cost may create a financial hardship on the QF, preventing it from operating economically.

According to Staff, the high cost of insurance would be a barrier to small QF operations, particularly wind and run of the river hydro. Staff presented six cases where the estimated cost of insurance would equal or exceed the possible revenues a small QF would receive under Idaho Power's Oregon Schedule 85. Staff observes that

[5] Staff notes that the 2005 Legislature in SB 84 delegated to the Commission the authority to increase the net metering eligible facility size for PGE and PacifiCorp (*see* docket AR 515).

none of the utilities was able to provide any examples where it was liable for damages because of the actions of a QF.

In its direct testimony Staff refers to various industry standards issued in recent years that address "islanding," safety and damage prevention. Staff states that it intends to propose rules to address uniform interconnection standards.

Staff states that FERC has declined to impose a generic insurance requirement on interconnections for small distributed generation resources. Staff cites a FERC order that "acknowledges that the risk of interconnecting small inverter-based generators is low," leaving the insurance issue for the states to consider. Staff opening brief, 27, citing FERC Order No. 2006 (RM02-12-000).

Staff states that many other states also have not placed mandatory insurance requirements on small QFs. Staff argues that the decision to carry liability insurance should not be mandated by the utilities, but be the responsibility of each small QF as a business decision.

Staff further notes that standard contracts include indemnification language to the effect that each party will agree to hold harmless and to indemnify against all loss, damage, fines, penalties, expense and liability to third persons for such instances as injury, death, or property damages. Staff argues that the indemnification clauses provide sufficient legal remedies and adequately protect the interests of the utility, its customers, and small QFs.

PGE argues that liability insurance is appropriate, no matter the size of the QF. According to PGE, there is no credible evidence that liability insurance for QFs less than 200 kW is either costly or difficult to obtain.

According to Idaho Power, the size of a QF facility is not related to the exposure of a utility in the event of an electrical contact or other incident. Idaho Power argues that the need for liability insurance for a 200 kW facility is just as serious as it is for a 20 MW facility.

Idaho Power reports that it currently has contracts with 11 QFs whose design capacity is 200 kW or less, and that each of these QFs maintains $1,000,000 of liability insurance. Thus, according to Idaho Power, "requiring reasonable levels of liability insurance is not a barrier to the development and operation of very small QF projects." Idaho Power opening brief, 14.

Idaho Power states that all QFs face liability risks. Idaho Power states that its primary motivation is to protect itself and its customers from the expense of defending itself in litigation, if a party has been injured and a QF is accused of negligence.

According to Idaho Power, left to themselves, many QF developers will choose to forego liability insurance to save money. Idaho Power states that such a result exposes the utility and its customers to potential expense and also exposes innocent third parties to the risk that they will not be able to recover damages for any injury.

In its reply brief, Staff notes that Idaho Power did not address three of the arguments raised by Staff: the analogy to net metering, the actions by other jurisdictions, and the indemnification clause in the standard contracts. Staff finds Idaho Power's arguments "unpersuasive."

2. Discussion

We agree with Staff. The net metering analogy offers a sharp contrast, where the risks would appear to be similar but the treatment to be starkly different, if we were to mandate insurance for QFs at or under 200 kW. Where the Legislature has expressed itself clearly, we would be highly likely to take a consistent position – even if Oregon were the only jurisdiction to reach that conclusion.

FERC declined to impose a mandatory insurance requirement, leaving the decision to the states. Many other states also have not adopted a mandatory insurance requirement. We find that the standard contract indemnification clause adequately protects the utility and its customers from liability for QFs up to 200 kW.

J. ENERGY POLICY ACT OF 2005

1. Position of Parties

The Energy Policy Act (EPAct) of 2005 allows a utility to apply to FERC for an exemption from its mandatory purchase obligation under PURPA. (Section 210(m).) In order for the request to be granted, FERC must find that specified market conditions are met. FERC Order 688 addresses the process by which electric utilities may apply to be relieved of the mandatory purchase obligation imposed by PURPA, as amended by Section 210(m). The Act also updated the efficiency requirements for cogeneration facilities and removed restrictions on utility ownership of QFs. FERC Order 671 addresses these and other provisions.

Based upon FERC's proposed rules, Staff concludes that the issue of a mandatory purchase obligation under federal PURPA is a matter of federal, rather than state, jurisdiction. However, Staff suggests the Commission consider updating its Division 29 rules to recognize this federal provision, as well as changes to ownership and efficiency standards.

PacifiCorp concurs with Staff's comments. In addition, PacifiCorp asserts that certain provisions in EPAct 2005 are relevant to the Commission's consideration of other issues in this case, such as cost recovery related to indexed pricing options.

PGE agrees the issue of a utility's mandatory purchase obligation is a matter of federal jurisdiction. However, the company believes that under

Section 210(m)(1), the utility may not be required to purchase from out-of-service territory QFs to which the exemption applies. Staff disagrees, stating that the exemption is not tied to the QF but to the electric utility in whose territory the QF resides. Further, Staff points out that each utility must apply for the exemption.

2. Discussion

We agree with the parties' general conclusion that issues regarding the utility's mandatory purchase obligation under PURPA are not for this Commission to resolve. Further, we agree with Staff that our Division 29 rules should be updated to reflect changes in federal PURPA requirements. We will open a rulemaking to do so. We also note that the 2007 Legislature's recent passage of SB 838 reinstates the requirements for PGE and PacifiCorp under the state PURPA law,[6] and our Division 29 rules will again apply to all three electric public utilities.

IV. CONCLUSION

We have adopted guidelines for the negotiation of nonstandard QF contracts attached as an Appendix. We also have resolved other issues remaining from the previous phase of this proceeding.

ORDER

IT IS ORDERED that:

1. The last sentence of the first full paragraph on page 28 of Order No. 05-584 is modified to read: "In such situations, utilities should use day-ahead on- and off-peak market index prices for non-firm purchases."

2. A new last sentence is added to the first full paragraph on page 28 of Order No. 05-584 that reads as follows: "Deliveries above the QF's nameplate rating solely for the purpose of accommodating hourly scheduling in whole megawatts by a third party transmission provider do not constitute 'excess' energy."

3. Portland General Electric Company, Idaho Power Company, and PacifiCorp shall submit modified tariffs to incorporate the decisions adopted in this order.

4. The guidelines in the Appendix are adopted.

[6] *See* ORS 758.505 through 758.555.

5. Each of the utilities shall conduct negotiations with QFs larger than 10 MW pursuant to the guidelines adopted in this Order.

6. Each of the utilities shall amend its tariffs consistent with the market price-based approach we adopt for as available QF deliveries.

7. Idaho Power Company's Schedule 86 is not approved.

8. Portland General Electric Company's and PacifiCorp's standard off-system QF contracts, as modified by this order, are approved.

9. The utilities shall modify their standard QF contracts for intermittent resources to include a mechanical availability guarantee in lieu of a minimum delivery obligation.

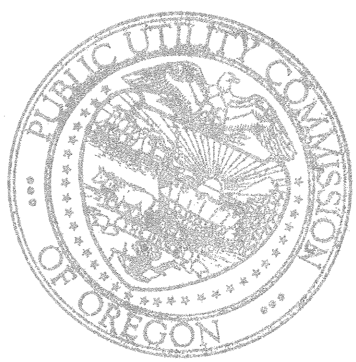
10. A rulemaking docket is opened to promulgate rules consistent with our decision in this order on dispute resolution for negotiated QF contracts and to update Division 29 rules for consistency with federal and state PURPA requirements and decisions in this proceeding.

Made, entered, and effective AUG 20 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner



A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

APPENDIX A

Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs[1] 10 MW or Larger

1. The utility should not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement is a useful starting point in negotiating QF agreements.

2. Utility tariffs should specify the following procedures for contract negotiations:

   a. The utility will provide an indicative pricing proposal for a QF that plans to provide firm energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The utility will provide an indicative pricing proposal within 30 days of receipt of the information the utility requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

      i. For Portland General Electric (PGE) and PacifiCorp, the yearly avoided costs approved for the 20-year period for standard contracts should serve as the starting point for negotiations. The prices may be modified to address specific enumerated factors approved by the Oregon Commission. The utility will provide to the QF a description of the methodology for each adjustment to standard avoided costs and how each adjustment was made.

      ii. For Idaho Power, the starting point for negotiations are the avoided costs calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

   b. The prospective QF may request in writing that the utility prepare a draft power purchase agreement to serve as the basis for negotiations. The utility may require additional information from the QF necessary to prepare a draft agreement.

   c. Within 30 days of receiving the required information, the utility will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

   d. The QF must submit in writing a statement of its intention to begin negotiations with the utility and may include written comments and proposals. The utility is not obligated to begin negotiations until it receives written notification from the QF.

[1] We use the term "QF" to mean the contracting party or the facility itself.

The utility will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

e. When the parties have agreed, the utility will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the party may file a complaint with the Oregon Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

3. QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

4. The utility should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. A utility shall not determine that a QF provides no capacity value simply because the utility did not select it through a competitive bidding process. For a QF providing firm energy or capacity:

   a. The utility and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the utility's partial requirements tariffs as guidance.

   b. The QF should be required to make best efforts to meet its capacity obligations during utility system emergencies.

   c. The utility and the QF should negotiate security, default, damage and termination provisions that keep the utility and its ratepayers whole in the event the QF fails to meet obligations under the contract.

   d. Delay of commercial operation should not be a cause of termination if the utility determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

   e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

   f. The utility should include a provision in the contract that states a utility may require a QF terminated due to its default and wishing to resume selling to the utility be subject to the terms of the original contract until its end date.

5. An “as available” obligation for delivery of energy, including deliveries in excess of nameplate rating or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

6. For QFs unable to establish creditworthiness, the utility must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the utility should take into account the risk associated with the QF based on such factors as its size and type of supply commitments. Default security methodologies specified in PGE’s and PacifiCorp’s standard QF contracts are a useful starting point for negotiations with large QFs.

7. When QF rates are based on avoided costs calculated at the time of delivery, the utility should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

    a. For QFs providing firm energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases.

    b. For QFs providing energy on an “as available” basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

8. The utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines.

9. The utility should make adjustments to avoided costs for reliability on an expected forward-looking basis. The utility should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

10. The utility should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

11. If avoided cost rates for a QF are calculated at the time of the obligation and the utility’s avoided resource is a fossil fuel plant, the utility should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

11. Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the utility's system, unless the QF contracts for integration services with a third party.

    a. The utility should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

    b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the utility proxy plant.

    c. The utility should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the utility expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

    d. The utilities are prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if a utility is subject to near-term targets under a mandatory Renewable Portfolio Standard, the utility may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

    e. In determining integration costs, the utility should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.

13. The utility should adjust avoided cost rates for QF line losses relative to the utility proxy plant based on a proximity-based approach.

14. The utility should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant and adjust avoided cost rates accordingly.

15. The utility should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

16. A utility should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

17. Regarding Surplus Sale and Simultaneous Purchase and Sale:

    (1) QFs may either contract with the purchasing utility for a "surplus sale" or for a "simultaneous purchase and sale" provided, however, that the QF's selection of

either such contractual arrangement shall not be inconsistent with any retail tariff provision of the purchasing utility then in effect or any agreement between the QF and the purchasing utility;

(2) The two sale/purchase arrangements described in paragraph (1) will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the “simultaneous purchase and sale” is not available to QFs not directly connected to the purchasing utility’s electrical system;

(3) The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph (1); and

(4) The avoided cost calculations by the utilities do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph (1), rather than the other.