BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities.	STAFF'S OPENING BRIEF Phase II, Track II Proceeding

I. Introduction

Administrative Law Judge (ALJ) Kirkpatrick described the purpose of the Phase II, Track II part of this docket as follows: "to address the substance of unexamined or partially investigated issues related to the development (of) QF contracts." Ruling at 2, (issued March 3, 2006). In the same Ruling, ALJ Kirkpatrick also adopted an Issues List containing 14 issues, many with subparts. The parties subsequently submitted testimony on all issues and waived the oral evidentiary hearing. Except as expressly stated otherwise in this brief, staff stands by the recommendations made in its filed written testimony.

In this Opening Brief, staff will first discuss its request for the Commission to correct what staff believes is an error found in a specific passage of Commission Order No. 05-584. Staff will then address each issue in the order listed in the ALJ's Ruling, with the recognition that the parties were able to resolve Issues 1(a), 5(b), 8 and 9 in their entirety and also settled most of the questions dealing with standard contracts for off-system "qualifying facilities" (QFs) identified under Issues 3(b) and 14. As a final note, staff addressed Issues 2 and 6 for standard contracts in the Phase I compliance investigation and addresses these same issues in Phase II, Track II only for non-standard contracts.

II. Preliminary request for correction/clarification to Order No. 05-584

In its reply testimony, staff asked the Commission to correct the following passage from Order No. 05-584 (at 28):

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> 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]

See generally Staff/2300, Schwartz/1-4.

Staff believes the Commission intended the last sentence to state: "In such situations, utilities should use the methodology that has historically been used when utilities are in a resource *sufficient* position." [Emphasis added]. In other words, staff believes the Commission intended that excess energy — energy deliveries exceeding the QF's nameplate rating — receive energy-only payments (no capacity payments) through payment of off-peak rates. Today, off-peak rates during the period of resource sufficiency are based on monthly off-peak forward market prices. During the period of resource deficiency, off-peak rates are based on the costs of the utility proxy plant, exclusive of capacity costs. *See* Order No. 05-584 at 27-28.

Staff further recommends the Commission clarify that "excess energy" does not apply to deliveries above the QF's nameplate rating solely for the purpose of accommodating hourly scheduling in whole megawatts by a third-party transmission provider. *See* Staff/2300, Schwartz/1-4.

III. The Issues

1. Development of negotiation parameters and guidelines for nonstandard QF contracts.

Attachment A is staff's proposed guidelines for the negotiation of QF power purchase contracts, pursuant to Administrative Law Judge Kirkpatrick's memo dated May 4, 2006.

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a. What contract length should Qualifying Facilities larger than 10 MW be entitled to? [Order No. 05-584 at 17]

The parties have settled this issue. *See* PPL/408, Griswold/1-12 (Stipulation); Staff/1800, Schwartz/3-5; PPL/404, Griswold/2; and PPL/407, Griswold/15-17.

b. How should QF power supply commitments differentiate between "as available" and "legally enforceable obligations" for delivery of energy and capacity?

The Federal Energy Regulatory Commission (FERC) defines "legally enforceable obligations" and "as available" supply commitments in 18 C.F.R. § 292.304(c)(3) and (d). Definitions in the Commission's PURPA rules are similar. *See* OAR 860-029-0010(13) and (16). Based upon these rules, staff views a "legally enforceable obligation" for delivery of energy and capacity as a firm commitment. Conversely, an "as available" obligation for delivery of energy and capacity should be treated as a non-firm commitment. *See* Staff/1900, Chriss/2.

Under the appropriate FERC rules, a QF that provides energy and capacity on an "as available" basis does so at the avoided cost rates based on the purchasing utility's avoided costs calculated *at the time of delivery*. *Id.* Further, the FERC rules provide that QFs that provide energy or capacity on a legally enforceable basis over a specified term can choose, prior to the beginning of that term, avoided cost rates based on either (i) the avoided costs at the time of delivery; or (ii) the avoided costs calculated at the time the obligation is incurred. A market-based rate is appropriate when QF payments are based on the utility's avoided costs at the time of delivery. *See* Staff/1900, Chriss/3.

Staff disagrees with PacifiCorp's position that QF contracts providing energy deliveries on an "as available" basis should only receive an "energy price," which PacifiCorp defines as its off-peak avoided cost rate in its Schedule 37. For as available deliveries, a market-based rate is appropriate. Staff/2400, Chriss/4-5. This recommendation is consistent with the FERC rule noted above. Id. Further, non-firm QFs should only receive value for their capacity to the extent their avoided costs are based on market prices during on-peak hours, with capacity value embedded in those prices. Staff/2400, Chriss/5.

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c. How should "firm" or "non-firm" supply commitments be defined and differentiated through contractual default and damages provisions?

Negotiated contracts for QFs that make *firm* supply commitments 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. Conversely, negotiated 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. That is because the utility does not count on "as available" energy deliveries.

Further, staff agrees with PGE that QFs that do not wish to make firm delivery commitments should receive payments for energy deliveries based on current market prices. The utility generally can buy and sell energy at these prices. Therefore, the utility and its ratepayers are not harmed if the QF resource is not on-line by its projected operation date, delivers less energy than expected based on its nameplate rating (after accounting for on-site and station needs), or if the QF owner chooses to terminate the contract early. *See* Staff/1800, Schwartz/6-7; Staff/1900, Chriss/2-3; and PGE/300, Kuns-Drennan/5.

d. How should avoided costs be adjusted for factors, such as those described in 18 CFR § 292.304, for a Qualifying Facility's specific power supply attributes and commitments?

a. *Data filed with avoided cost filing, including state review of data* [18 C.F.R. § 292.304(e)(1)]

Any net costs or benefits of the QF, relative to the proxy plant data in the utility's approved avoided cost filing, and as approved for consideration by the Oregon Commission in adjusting avoided costs, should be taken into account in negotiating avoided cost rates. *See* Staff/1800, Schwartz/9.

b. *Availability of QF capacity or energy during the system daily and seasonal peak periods* [18 C.F.R. § 292.304(e)(2)]

i. *Ability of the utility to dispatch*

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First, adjustments to avoided costs for dispatchability should be made only during the utility's resource *deficiency* period, when avoided costs are based on the dispatchable utility proxy plant. Avoided costs during the utility's resource sufficiency period are based on monthly on- and off-peak forward market prices, not a dispatchable proxy plant. *See* Order No. 05-584 at 28; Staff/2300, Schwartz/9.

Second, staff agrees with PacifiCorp that 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 availability of the proxy utility plant on which avoided cost are based. *See* PPL/404, Griswold/6. However, staff disagrees with the company that the QF provides no capacity value if its availability is less than that of the utility proxy plant. For example, under PacifiCorp's proposal the QF would receive no capacity payment if its availability is below 85%. In other words, the QF would receive only off-peak prices for all energy delivered that month. *See* Staff/2300, Schwartz/5; Staff/2301, Schwartz/1-2.

PacifiCorp's proposal also fails to recognize the difference in QF value based on its degree of availability – for example, between a QF with an on-peak capacity factor of 20% vs. a QF with an availability of 80%. *See* Staff/2300, Schwartz/6.

Further, PacifiCorp's proposal does not adjust for the additional value of a QF with a higher availability than the utility proxy plant. Staff agrees with Weyerhaeuser-ICNU in principle that 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. *See* Weyerhaeuser-ICNU/300, Beach/12; Weyerhaeuser-ICNU/300, Beach/4-5. However, the adjustment for superior QF availability should be made relative to the availability of the *utility proxy plant*, consistent with Order No. 05-584 (at 27), not the QF contract capacity level as Weyerhaeuser-ICNU proposes. *See* Weyerhaueser-ICNU/300, Beach/12-13; Staff/2300, Schwartz/7-8.

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It is important to note that a QF should not receive an additional capacity payment for providing capacity in excess of its stated contract commitments. Staff views this as a form of "excess energy" which the utilities cannot rely on. Therefore, payment to the QF for on-peak deliveries in excess of the contracted amount should not include an explicity capacity value, consistent with Order No. 05-584 (at 28). In other words, the adjustment to capacity payments for superior QF on-peak performance, relative to the utility proxy plant, should be limited to performance within the bounds of the QF's contracted capacity. This proviso addresses the concern Idaho Power raises related to Weyerhaeuser-ICNU's proposal for bonus payments. Idaho Power's recommendation that deliveries above the amount committed in the contract be valued at non-firm energy prices is reasonable. *See* Idaho Power/400, Gale-Allphin/4-5.

To address both inferior and superior availability of the QF, relative to the utility proxy plant, the Commission should require each utility to develop a sliding scale model to calculate adjustments to capacity payments that would apply to actual monthly QF performance during peak periods. *See* Staff/2300, Schwartz/5-8.

Neither PacifiCorp's nor Weyerhauser-ICNU's proposal addresses the value of being able to call on the QF to decrease (or increase) its output in response to real-time electricity and natural gas prices. Therefore, Weyerhauser-ICNU's proposal for time-of-use energy rates is a poor substitute for real-time economic dispatch. *See* Staff/1800, Schwartz/10-11; Staff/2300, Schwartz/8-9. In rebuttal testimony, Weyerhauser-ICNU propose paying QFs based on day-ahead on- and off-peak prices to address dispatchability. *See* Weyerhauser-ICNU/304, Beach/5-6. Staff does not agree with this proposal, as illustrated by the following example.

Say the utility proxy plant, a combined-cycle gas turbine, dispatches at a price of $50 per megawatt-hour, and the day-ahead on-peak market price is $90 per megawatt-hour. Staff does not believe the $40 per megawatt-hour difference represents the differential value of dispatchabiility between the utility proxy plant and the QF. Nor do day-ahead market prices necessarily reflect the cost the utility would avoid by purchasing from the QF. The value of

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dispatchability is more appropriately determined through the probabilistic analysis staff recommends - IRP-type modeling with stochastic analysis of electric and natural gas prices, loads, hydro and unplanned outages.

Stochastic modeling under various futures, such as that used by the utilities in Integrated Resource Planning (IRP), could address the reduced value of a "24-7" natural gas-fired combined heat and power facility, relative to the dispatchable utility proxy plant. Idaho Power agrees with this approach and states that its AURORA model can be used in this way to estimate the cost of QF non-dispatchability. While the Idaho Public Utilities Commission (IPUC) requires the company to use its IRP model to determine avoided costs for large QFs, staff found nothing in the IPUC's order requiring *stochastic* analysis. However, the company appears willing to incorporate stochastic analysis in IRP modeling to determine avoided costs for large QFs. *See* Staff/1800, Schwartz/11; Staff/2300, Schwartz/9-10; Idaho Power/400, Gale-Allphin/9-11.

To the extent the FERC adjustment factor addressing dispatchability may address only *peak* periods, the value of dispatchability in off-peak period (being able to call on the generator to shut down or decrease its output) may be addressed under 18 C.F.R. § 292.304(e)(2)(vi) or 18 C.F.R. § 292.304(e)(3). *See* Staff/2300, Schwartz/8-9.

Finally, Weyerhaueser-ICNU propose to de-rate a QF's capacity if it falls below the contracted level until the QF can demonstrate its ability to provide a higher level of capacity. *See* Weyerhaeuser-ICNU/300, Beach/12-13. If capacity payments to the QF are fixed (in dollars per kilowatt-year), de-rating the QF's contract capacity is a reasonable alternative to termination due to QF non-performance. However, if market prices during the non-performance period are higher than the QF contract price, and reduced payments to the QF for reduced availability do not keep the utility whole, damages may be appropriate for failure to meet the contracted capacity level. *See* Staff/2300, Schwartz/7.

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ii. *Reliability*

Staff agrees with Weyerhaeuser that QF contracts for firm power may provide strong incentives for high reliability through fixed capacity payments (in dollars per kilowatt-year) that are tied to performance during the utility's peak period. *See* Weyerhaeuser/104, Beach/4; Staff/1800, Schwartz/11.

iii. *Contract terms, including duration, termination notice and sanctions for noncompliance*

The yearly avoided costs the utilities file for the 20-year period should serve as the starting point for negotiations. *See* Order No. 05-584 at 20-21. The QF should have the discretion to choose a contract term up to 20 years. *See* Staff/1800, Schwartz/3-5, 11-12; PPL/408, Griswold/11 (Stipulation).

With one exception, the Commission should impose on non-standard contracts the same conditions regarding termination as staff recommended in the Phase I Compliance portion of this proceeding. *See* Staff/1000, Schwartz/36-38, 41-43, 48-49; Staff/1500, Schwartz/21-22. The exception is that the Commission should not prescribe the time period over which the utility may seek termination damages. *See* Staff/1800, Schwartz/12.

If sanctions for noncompliance in the negotiated QF contract "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of [a specified amount of] energy or capacity over a specified term," the QF should receive rates based on providing firm power to the utility. *See* 18 C.F.R. § 292.304(d)(2); Staff/1800, Schwartz/12.

iv. *Extent to which scheduled outages can be usefully coordinated with scheduled outages of the utility's facilities*

The utility and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement. Provisions in the utilities' standby tariffs may provide guidance. *See* PGE Schedule 75 and PacifiCorp Schedule 247; Staff/1800, Schwartz/12-13.

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v. *Usefulness of QF energy and capacity during system emergencies*

A QF should be required to make best efforts to meet its capacity obligations during utility system emergencies. However, the QF should not be penalized for an unplanned outage during a utility system emergency, so long as the outage falls within other parameters in the contract. *See* Staff/2300, Schwartz/10-11.

vi. *Individual and aggregate value of energy and capacity of the QFs on the utility's system*

The utility's IRP or production cost model could assess the aggregate value of QFs on the utility's system. However, the QF should receive no more of the aggregate value than the incremental value it contributes. *See* Staff/1800, Schwartz/13.

vii. *Value of smaller capacity increments and shorter lead times*

Theoretically, benefits of QFs to the utility system, such as reduction in forecasting risk related to load/resource balance, technological obsolescence and regulatory risk could be quantified in IRP-type modeling with stochastic parameters. *See* Staff/100, Breen/20-21; Staff/1800, Schwartz/13.

c. *Ability of the utility to avoid costs, including deferral of capacity additions and reduction of fossil fuel use, due to the availability of energy and capacity from the QF* (18 C.F.R. § 292.304(e)(3))

QF payments should reflect the utility's avoided capacity costs. Dispatchable QFs should receive fixed capacity payments (in dollars per kilowatt-year), reflecting the avoided capacity costs of the utility proxy plant. It is reasonable for wind QFs to receive fixed pricing per megawatt-hour.

The Commission is addressing in other dockets how to take into account the risk mitigation value of non-fossil fuel resources in resource planning and competitive bidding (i.e. UM 1056 and UM 1182). If the utility proxy plant for determining avoided costs is a natural gas-fired combustion turbine, the negotiated avoided cost rates for wind and other renewable resources should reflect avoided natural gas-price risk. The Commission should aim to make utilities and ratepayers neutral regardless of whether the utility's resource planning goals are

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achieved through QF contracts, competitively procured contracts or utility-owned resources. *See* Staff/1800, Schwartz/14.

Weyerhaeuser-ICNU state that avoided cost rates for natural gas-fired CHP projects that are more efficient than the utility proxy plant also should reflect gas price mitigation value. *See* Weyerhaeuser-ICNU/304, Beach/7-8. State notes that Weyerhaeuser-ICNU's proposal to require utilities to offer large QFs a gas-market pricing option would reduce their value for mitigating natural gas price risk.

d. *Variations in line losses* (18 C.F.R. § 292.304(e)(4))

If QFs are located at or near customer sites, line losses and other transmission and distribution (T&D) costs may be lower than for the utility proxy plant, which typically is sited in a remote location. *See* Staff/1800, Schwartz/14-15. Staff finds PacifiCorp's proposal for adjusting avoided costs for line losses reasonable. *See* Staff/2300, Schwartz/11; Staff/2301, Schwartz/3; PPL/407, Griswold/5-6.

Staff agrees with Weyerhaeuser-ICNU and PacifiCorp that transmission costs which 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. However, any distribution level savings are dependent on the reliability of the QF. Load shedding by the QF host may be required in the case of a QF outage during pre-determined peak hours for the relevant components of the local utility grid. Any analysis of potential T&D system savings should include projected load growth and associated T&D needs. *See* Staff/1000, Schwartz/14-15; Weyerhaeuser-ICNU/200, Beach/15; Staff/2300, Schwartz/11; and Staff/2301, Schwartz/4-5. *Also see* Order No. 06-029 at 55-56.

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,

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staff agrees with PacifiCorp that avoided cost rates for non-standard PURPA contracts should be adjusted to account for the higher cost of non-dispatchable QF power. *See* PPL/404, Griswold/7-8; Staff/2300, Schwartz/12.

T&D costs and savings, other than line losses, may fall within 18 C.F.R. § 292.304(e)(2)(vi), "The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system." If power from a QF is higher cost than power from other resources available to the utility, it can be considered to be of lower "value" than the lower cost power obtainable from other resources. The reverse also is true. Another FERC factor, 18 C.F.R. § 292.304(e)(3), may be relevant, "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…." *See* Staff/2300, Schwartz/12-13.

General issues under issue 1(d) regarding negotiation of avoided cost rates for non-standard contracts

Contract Provisions

Staff witness Schwartz agrees with Weyerhaeuser that contract provisions, rather than pricing adjustments, can address some of the FERC adjustment factors. *See* Staff/1800, Schwartz/8; Weyerhaeuer/104, Beach/4. PGE disputes that certain factors should only be addressed in contract provisions. The company states that pricing and contractual provisions are not "either-or" conditions but are necessarily linked, and contract terms help determine the value of the power received. *See* PGE/500, Kuns-Sims/4.

Staff does not disagree with the company on this point. Rather, staff's view appears to be similar to PGE's. The company states that an adjustment to avoided costs is needed to value resource differences *unless* contract terms "[a]ssure that the QF matches the attributes of the avoided cost resource in all material respects." *See* PGE/500, Kuns-Sims/4.

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Staff and Weyerhaeuser agree that widely-used templates, such as the Edison Electric Institute (EEI) master agreement, may serve as a foundation for negotiated QF contracts. *See* Weyerhaeuser/100, Beach/3; Staff/1000, Schwartz/4; and Staff/1800, Schwartz/8.

PGE agrees that the EEI master agreement may be helpful as a guide. However, the company believes the agreement generally is not suitable for wholesale energy transactions involving specific resources where the production or delivery characteristics do not meet the definition of standard electric commodity products. Therefore, PGE does not recommend that the EEI master agreement be a required template for non-standard QF contracts, but rather a reference point for consistency with standard practices in developing bilateral agreements for specific energy resources that take into account unique project characteristics. *See* PGE/500, Kuns-Sims/3. This is consistent with staff's position.

Idaho Power agrees that portions of the industry-standard EEI master agreement should provide the basis for negotiating non-standard contracts with large QFs. *See* Idaho Power/400, Gale-Allphin/4.

Idaho Power

In rebuttal testimony, Idaho Power recommends the Commission allow it to use the IRP methodology approved by the IPUC to determine avoided costs for large QFs in Oregon. *See* Idaho Power/400, Gale-Allphin/10-11. This Commission determined in Phase I of Docket UM 1129 that the company would generally use the methodology approved by the IPUC to calculate *standard* avoided cost rates for small QFs in Oregon. *See* Order No. 05-584 at 26-27. Staff would not object to the Commission similarly deferring to the IPUC's approved methodology for calculating avoided cost rates when negotiating with large QFs.

Staff notes that the method approved by the IPUC may be a deviation from Commission Order No. 05-584, which states (at 12 and 59) that standard avoided costs serve as the starting point for negotiations with large QFs. Idaho Power uses different inputs, and a different approach, to calculate standard avoided cost rates for small QFs in Oregon than would be used

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under the IPUC-approved method for large QFs. The Idaho method determines the difference in present value of revenue requirements, over the lifetime of the QF contract, between 1) the utility's "base case" resource plan and 2) a modified resource plan that includes the QF resource, with its costs set to zero, and associated adjustments to the amount or timing of other new resources. Also, the IPUC allows the company to *update* IRP data such as forecasted prices for natural gas to calculate avoided cost rates for large QFs. *See* Idaho Public Utilities Commission Order No. 26576 (Case No. IPC-E-95-9); Staff/2300, Schwartz/16-17.

Deviations From Standard Rates and Contract Pre-approval

Staff agrees with Weyerhaeuser-ICNU that the utility should explain in writing the reason for any modifications of standard avoided cost *rates* when it is negotiating non-standard QF contracts. However, staff does not agree with Weyerhaeuser-ICNU that the utility should identify modifications to the standard *contract*. Instead, the utility should simply comply with the negotiation guidelines the Commission adopts in its order in this phase of Docket UM 1129. The standard contract is specifically designed for small QFs, not large QFs. At the same time, negotiated QF contracts should not impose terms and conditions beyond what is standard practice for the utility's other power transactions. *See* Weyerhaeuser-ICNU/300, Beach/5-6, 23-24; Staff/2300, Schwartz/13.

PGE asserts that requiring the utility to state in writing the reason for any deviations from standard avoided cost rates, including their quantitative basis, would be one-sided and "unwieldy" given the dynamic nature of bilateral negotiation. *See* PGE/500, Kuns-Sims/6. Instead, PGE proposes that the Commission approve each non-standard QF contract. *See* PGE/400, Kuns-Sims/2, 13; PGE/500, Kuns-Sims/6-7.

Staff disagrees with PGE that each large QF contract be contingent on Commission approval. Moreover, the Commission already decided this issue in Order No. 05-584 at 56. *See* Staff/500, Breen/3; Staff's Phase I Opening Brief at 11; and Staff/2300, Schwartz/14. Staff

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continues to support written justification for adjustments to standard avoided cost rates for non-standard contracts.

Green Tags

The Commission has previously determined that the avoided costs paid under PURPA contracts do not convey the Tradable Renewable Certificates, or green tags, associated with generation from renewable resource QFs. *See* Order No. 05-1229 (Docket AR 495). However, the utilities can negotiate ownership of the green tags, and associated tag payments, when negotiating PURPA contracts for QFs over 10 MW. A constraint on PGE and PacifiCorp in this regard is that the total contract cost that goes into rates must not include the "above market" costs of new renewable resources. *See* ORS 757.612(3)(g). To the extent acquiring the green tags would be an above-market cost for the utility, the Energy Trust of Oregon (ETO) may provide support. *See* ORS 757.612(3)(d). The utility should consider the value of owning the green tags to mitigate the risk of potential Renewable Portfolio Standard (RPS) requirements in the future. *See* Staff/1800, Schwartz/15.

e. Regarding PacifiCorp's Schedule 38 for Qualifying Facilities larger than 10 MW, are the procedures for negotiating avoided costs, schedules for negotiations, and the information to be exchanged by PacifiCorp and the Qualifying Facility reasonable?

Staff finds the provisions in PacifiCorp Schedule 38 generally to be reasonable, with the following exceptions. First, references to pricing options for QFs over 10 MW (fixed, deadband or gas indexed) are premature, as the Commission is addressing this issue in the current phase of this proceeding. Second, the utility should not require that interconnection studies be completed prior to providing the QF with a draft power purchase agreement. Currently, the utility controls the timelines for interconnection studies for QFs and may be the source of delays.[1] Also, it takes time to resolve issues once the QF has the draft power purchase agreement.

[1] Staff has begun work on a rulemaking to implement uniform interconnection technical standards, procedures (including timelines) and agreements for Oregon electric companies, pursuant to the Commission's objectives and the Energy Policy Act of 2005. *See* Staff/2100, Dougherty/6.

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Third, the tariff should specify timelines for providing a final draft agreement after the utility has received all the information it needs to do so, as well as for providing the final executable agreement after parties are in full agreement on terms and conditions. Staff recommended timelines for these events for standard contracts in a previous phase of Docket UM 1129. Finally, parameters and guidelines for negotiating non-standard contracts determined through the current proceeding should be reflected in the utilities' compliance filings following the Commission's order. *See* Staff/1500, Schwartz 59-62; Staff/1800, Schwartz/20-21.

f. Can the utilities adjust the avoided cost calculations for Qualifying Facilities over 10 MW based on factors that have not been approved by the Oregon Public Utility Commission?

Staff agrees with Weyerhaeuser-ICNU that the utility should not be allowed to make adjustments to standard avoided cost rates for QFs larger than 10 MW other than those approved by the Commission. Staff reads the FERC rules on adjustment factors as specifying *all* the factors that can be taken into account. In other words, it is an all-inclusive list. PacifiCorp disagrees. *See* PPL/407, Griswold/11-12.

Further, the Oregon Commission ordered a second phase of this proceeding in large part to determine negotiation parameters and guidelines for nonstandard QF contracts, including adjustments to standard avoided cost rates. If a utility or other party foresaw the need to address a particular factor in determining the appropriate cost rates for these contracts, they should have raised the issue in this proceeding for a Commission decision. *See* Weyerhaeuser-ICNU/300, Beach/24; Staff/1800, Schwartz/15-16.

Staff disagrees with PacifiCorp that rate cases provide a venue for the Commission to review adjustments to avoided cost rates that it did not previously approve and that result in lower cost QF contracts. It is unlikely the Commission would review during a rate case whether a downward adjustment to avoided cost rates for a QF contract was appropriate, and then seek to increase the prices established in the executed QF contract and add that customer rates. *See* PPL/404, Griswold/11; and Staff/2300, Schwartz/13-14.

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2. In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required.

Staff basically proposes the same standard for large QFs who are unable to establish creditworthiness as staff recommended for QFs eligible for a standard contract. *See* Staff/2000, Morgan/2; Staff/2500, Morgan/2; Order No. 05-584 at 45. Staff believes its proposal is acceptable, or not objectionable, to the parties.

3. Further exploration of how the calculation of avoided cost should reflect the nature and quality of QF energy. Specifically:

a. How should firm vs. non-firm commitments and integration of intermittent resources affect the calculation of avoided costs? [Order No. 05-584 at 39]

Staff discussed the effect of firm vs. non-firm commitments on the calculation of avoided costs under Issue (1)(b) above. *See also* Staff/1900, Chriss/2-4; Staff/2400, Chriss/4-6.

Regarding integration costs[2] for intermittent resources, staff first recommends that standard avoided costs not be adjusted for such costs. The methodology the Commission adopted in Order No. 05-584 for calculating standard avoided costs is a reasonable estimate of the costs the utility will avoid by purchasing from the small QF, even taking into account integration costs. Actual costs the utility avoids for a particular project may be higher or lower than the estimates. The benefits of the small QF vs. the utility's proxy plant, as well as any higher costs, are not taken into account for standard contracts. For example, wind generation offers benefits such as fuel diversity and reduction in emission costs that are not captured in standard avoided cost rates. Further, integration costs for adding a 10 MW wind project to PacifiCorp's system, for example, are less than a dollar per MWh for imbalance costs and near zero for reserve requirements. *See* Staff/600, Schwartz/3,7; Staff/601, Schwartz/1-4; and Staff/1800, Schwartz/23.

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[2] "Integration" means accommodating the variable generating output of intermittent resources, such as wind, in the utility system to meet retail load and long-term firm sales obligations. Integration costs cover 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. *See* Staff/1800, Schwartz/22.

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For larger wind projects, however, staff recommends that avoided cost rates be adjusted for integration cost estimates based on studies conducted for the company's system. Idaho Power and PacifiCorp concur. *See* Idaho Power/400, Gale-Allphin/15; PacifiCorp/404, Griswold/12-14. PGE simply states that large QFs using intermittent resources should be priced in a manner consistent with avoidable costs for a particular supply with comparable uncertainty about timing and power delivery. *See* PGE/400, Kuns-Sims/15.

Consideration of these costs appears to fit under the FERC adjustment factors described in 18 C.F.R. § 292.304(e)(2)(iv): "The individual and aggregate value of energy and capacity supplied from qualifying facilities on the electric utility's system," and in 18 C.F.R. § 292.304(e)(3): "The relationship of the availability of energy or capacity from the qualifying facility ... to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use." *See* Staff/1800, Schwartz/22.

Staff recommends the Commission require the utilities to base first-year integration costs on the *actual* level of wind resources in the utility control area, plus the proposed project. Integration costs from years two through five of the contract should be based on the expected level of wind resources in the control area each year, including new resources the utility expects to add through its resource planning and acquisition processes. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects. *See* Staff/1800, Schwartz/22-28; Staff/2300, Schwartz/18.

PacifiCorp misconstrues staff's testimony on integration costs. *See* PPL/407, Griswold/7. Staff is not recommending a project-specific approach, as PacifiCorp implies. Instead, staff recommends that the Commission not allow the utilities to use a *long-term planning* target as the basis for determining its integration costs. Rather, 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

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planning and acquisition processes *over the next five years*. Planned resource actions beyond five years are unreliable.

For example, PacifiCorp should not use the $4.64 per megawatt-hour integration cost it proposes. *See* PPL/404, Griswold/14. That is because this estimated cost is based on integrating *one thousand* megawatts of wind resources within a control area, not the actual, low level of such resources in each of its control areas today serving PacifiCorp customers – 41 MW on the West side and 140.5 MW on the East side. Integration studies, including the one that PacifiCorp conducted for its 2003 IRP and updated for its 2004 IRP, have shown that integration costs are low at low wind penetration levels and rise as the amount of wind on the system increases.

PacifiCorp estimated the imbalance cost for integrating wind resources on the West side of its system at only about a dollar per megawatt-hour at wind penetration levels of about 200 MW. Imbalance costs are even lower on the East side of its system. Further, the modeling used to estimate these imbalance costs did not account for changes in the dispatch of hydro resources that can reduce imbalance costs. The incremental reserve requirements for integrating several hundred megawatts of wind in each control area are minimal. *See* Staff Exhibit 601; Staff/1800, Schwartz/25-28; Staff Exhibit 1802.

An alternative to staff's recommendation to base integration costs on existing wind penetration levels plus planned wind additions over the next five years is to base those costs only on the *current* level of wind resources within each control area, assuming the large wind QF comes on line. In other words, the utility would not take into account the amount of its *planned* wind acquisitions over the next five years. This would be consistent with standard ratemaking practice to use only known and measurable loads and resources when setting cost-of-service rates. This assumption also may be reasonable if the federal production tax credit is not extended in a timely manner or if there is a prolonged scarcity and high prices for wind turbines.

Staff did not recommend this alternative because the utilities' acknowledged IRPs put them on a path to acquire sizable levels of wind resources. Therefore, staff's recommendation

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strikes a balance between each utility's current wind penetration level and planned acquisitions. The other options staff considered, based on the midpoint in integration costs or in installed capacity, would not provide as accurate an estimate as staff's proposal. These options also do not address uncertainty related to resource actions beyond five years. *See* Staff/1800, Schwartz/27-28; Staff/2300, Schwartz/17-18.

Staff recommends 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 due to integration costs. Second, the utility should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources. Third, analysis of incremental reserves costs associated with integrating intermittent resources needs refinement. The utilities should compare the reserves costs for the wind QF with the reserves costs of the utility proxy plant and adjust avoided cost payments to large QFs based on the *difference* in reserves costs between the two types of facilities. That is because the utilities are not paying QFs for reserves through avoided cost rates. Both the QF and the proxy utility plant would pose additional costs for reserves. *See* Staff/1800, Schwartz/24-26.

The Public Service Commission of Utah already has determined that PacifiCorp overstates wind integration costs. The Utah Commission adopted an integration cost of $3 per megawatt-hour at this time. *See* Staff/1800, Schwartz/26-27.

Finally, staff recommends that a utility may negotiate scheduling requirements for deliveries from a large QF. For example, PacifiCorp states that energy supplied by a QF under a day-ahead schedule qualifies as a firm product if the contract obligates the QF to deliver a specified minimum quantity of energy to the Company and the QF meets the day-ahead schedule. *See* Staff/2300, Schwartz/15; Staff/2301, Schwartz/6-7.

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b. Costs and contractual provisions necessary to address purchases from QF projects that are located outside the utility's control area

Other than one matter, this Issue has been effectively settled. *See, e.g.*, Staff/2200, PPL/405, PPL/406 and PPL/409. The one remaining area of concern relates to PacifiCorp's off-system contract. *See* PPL/406. Staff originally recommended that if a QF delivers energy in excess of actual net output during the settlement period ("Surplus Delivery"[3]), the utility should pay the QF the off-peak price for it. *See* Staff/2200, Brown/6. PacifiCorp objected to staff's recommendation, arguing it would create an incentive for a QF to "game the system." The company stated that the QF could purposefully schedule more energy than it could deliver, purchase the deficit at the OATT price, and be compensated for the Surplus Delivery at PacifiCorp's off-peak tariff rate which, due to prevailing market conditions, could be higher than the OATT price. *See PPL*/409, Griswold/3-4.

In response to PacifiCorp's objection, we clarify that staff's recommendation is that the QF be compensated for Surplus Delivery at the non-firm off-peak *spot* price, which reflects the market value at the time of delivery.

4. Further exploration of a Mechanical Availability Guarantee (MAG). For example, are avoided cost prices affected by a Mechanical Availability Guarantee?

"Mechanical availability" is the percentage of time that the facility is actually producing 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. *See* PPL/404, Griswold/17.

Avoided cost prices are not affected by the MAG, a performance standard for intermittent resources such as wind and run of the river hydro. A MAG only affects payments to the QF to the extent it does not meet its contractual commitments under the MAG. Such a performance

[3] PPL/406, Griswold/W-1.

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standard would reinforce the Commission's previous order that intermittent and non-intermittent resources should be valued equally, and that intermittent resources should receive full avoided costs for deliveries under a standard contract. *See* Order No. 05-584 at 28; Staff/1000, Schwartz/24-32; Staff/1800, Schwartz/29-31; PPL/404, Griswold/15.

Staff recommends the Commission require the utilities to include a MAG in *standard* PURPA contracts for *firm* supply commitments. Contracts for *non-firm* supply commitments should not include a MAG. *See* Staff/100, Breen/18-19; Staff/500, Breen 13-15; Staff/1000, Schwartz/25-32; Staff/1800, Schwartz/29-30.

PacifiCorp recommends that power purchase contracts for intermittent QFs, regardless of size, include a MAG. In other words, the MAG should apply both to standard and non-standard contracts for QFs that rely on wind and run of the river hydro. *See* PPL/407, Griswold/1. The company states that its MAG approach recognizes that QFs relying on intermittent resources cannot accurately forecast generation output months in advance, and therefore holds the QF to performance it can control – the mechanical availability of its turbines. Without the MAG, the company would have less confidence in the QF's minimum annual output, because the QF would have less incentive to invest in the reliability and maintenance of the turbines. *See* PPL/404, Griswold/15-19.

While PGE states that "[t]he MAG may ... be used in standard contracts (<10 MW)," the company prefers to retain its Minimum Net Output provision in lieu of a MAG. PGE contends that neither provision will produce more or less power for a particular site because the only way a standard contract QF maximizes revenues is to maximize energy output. *See* PGE/400, Kuns-Sims/19; PGE/500, Kuns-Sims/10.

Staff and PacifiCorp disagree with PGE's reasoning. The delivery commitment under a MAG is based on fixed percentages of the QF's *full* output when wind and water are available, except for excused events such as too much or too little wind, scheduled maintenance and force majeure. Under the currently approved standard contracts, QFs base their minimum delivery

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obligation on the output predicted under *worst-case* motive-force conditions. A MAG gives the QF an additional incentive (avoidance of a penalty) to maximize availability, compared to an obligation based on worst-case wind or water conditions. Further, a MAG would avoid disputes over determination of the QF's minimum delivery obligation and mitigate many of the concerns related to weather, long-range resource forecasting, and default and damage provisions that parties have raised throughout this proceeding. *See* Staff/1800, Schwartz/29; PPL/404, Griswold/15-19.

PacifiCorp proposed use of a MAG for the 17.5 megawatt Schwendiman PURPA wind project in Idaho. Staff finds the proposed MAG for this project to be a reasonable template. *See* Staff/1000, Schwartz/25-26; Staff/1800, Schwartz/30-32.

Oregon Department of Energy (ODOE) supports the recommendation by staff and PacifiCorp that the Commission require the utilities to include a MAG in standard contracts for intermittent resources such as wind and run of the river hydro. However, ODOE is concerned that PacifiCorp's proposed MAG for the Schwendiman project does not adequately address potential unscheduled maintenance. ODOE therefore recommends that the Commission adopt one of two options for standard contracts for QFs 10 MW or less: 1) set the guarantee for mechanical availability at 65% to accommodate unscheduled maintenance events due to significant delay by third-party vendors or suppliers to provide the needed parts of service, or 2) excuse delays caused by third-party vendors as an exception to delivery under a MAG. *See* ODOE Exhibit No. 10, Keto/1-2. If the Commission is inclined to address this concern, staff recommends ODOE's first option, i.e. reducing the required mechanical availability level.

For *non-standard* PURPA contracts, staff recommends the utility and QF negotiate whether to incorporate a MAG or a minimum delivery obligation. Both PGE and PacifiCorp have used a MAG for *non*-PURPA negotiated wind contracts. In addition, PacifiCorp revised its generic power purchase agreement for its Request for Proposals (RFP) for renewable resources to incorporate a MAG based on annual guaranteed availability. *See* PacifiCorp's March 21,

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2006, filing to amend RFP 2003-B (Docket UM 1118), Appendix E-1, Section 6.12 (http://www.pacificorp.com/File/File63013.pdf). It likewise is reasonable for utilities and QFs to negotiate MAGs for non-standard PURPA contracts. *See* Staff/1800, Schwartz/32-33; Staff/1801, Schwartz/1-3.

PGE notes that a MAG is one of a variety of options that may be useful in non-standard contracts for large QFs as an incentive to assure that production capability is maintained over the life of the power purchase agreement. The company also sees the MAG's value for monitoring QF availability. PGE states, "The MAG incents the QF to maintain the facility in working order and provides the utility information about the project's on-going viability and potential production." *See* PGE/400, Kuns-Sims/19. Staff finds the reasoning here to apply equally well to small QFs eligible for standard contracts.

5. Further exploration of market pricing options and alternatives to using nameplate capacity to determine the size of a QF project for standard contract eligibility purposes, including:

a. Should PacifiCorp offer a market pricing option? [Order No. 05-584 at 35]

While the Commission did not direct PacifiCorp in its Order No. 05-584 to offer a market-indexed pricing option for standard contracts, it would be appropriate for PacifiCorp to do so. Staff/1900, Chriss/5. Staff offered some suggestions for how PacifiCorp should structure such an option. *See* Staff/1900, Chriss/5-6. Staff further showed that PacifiCorp's professed concern about the volatility of the market is inconsistent with the fact that the company currently has two Commission-approved market-based options. *See* Staff/2400, Chriss/7-8.

Pricing Options for QFs Larger Than 10 MW

The Commission should not require the utilities to offer QFs larger than 10 MW the pricing options made available to smaller QFs under Order No. 05-584 (at 34-35). At the same time, the Commission should not preclude the utilities from offering such options during their negotiations with the larger QFs. Staff/1900, Chriss/7-9; Staff/2400, Chriss/2. Staff's recommendation is reasonable for two primary reasons: (1) it allows the utility to refuse to offer

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such an option when it would be inappropriate to do so, and (2) it similarly allows the QF to keep its pricing options open during the negotiation process. *Id.*

b. Provide clear definition of "nameplate capacity" if that is retained as basis for defining eligibility for standard contracts and avoided cost rates.

The parties have settled this issue. *See* PPL/408, Griswold/11 (Stipulation) and Staff/1800, Schwartz/34.

6. Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.

Staff recommends that the Commission not impose a limit, or cap, on the default losses that may be recouped from a large QF. Staff's recommendation is reasonable because of the potential risks to a utility and its ratepayers associated with the default of a large QF, the fact that a large QF generally has greater financing flexibility than does a small QF, and the need to offer an incentive (albeit a negative one) to keep a large QF from inappropriately abandoning its project. *See* Staff/2000, Morgan/3; PGE/400 at 20.

7. Liability insurance for QFs with a design capacity at or under 200 kW.

In direct testimony on this issue, Staff points out that utilities should not be allowed to mandate liability insurance coverage for QFs at or under 200 kW for four reasons. These reasons are:

1. Potential costs and relative risk compared to net metering facilities;
2. Low risk;
3. Actions by other jurisdictions; and
4. Indemnification.

<u>Potential costs and relative risk compared to net metering facilities</u> – ORS 757.300(4)(c) prohibits utilities from requiring net metering facilities to purchase additional liability insurance. So although a 25 kW net metered producer is not required to maintain additional insurance under the net metering statute, a small QF producing 30 kW under a PURPA power purchase agreement would need to maintain a certain level of liability insurance if the Commission allowed the utilities to mandate coverage. This is of particular concern since the utilities

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proposed in Phase I of this docket to mandate insurance for all size QFs. Even though the risks would not be appreciably different between the two facilities, the operating expense for the 30 kW QF could potentially be significantly higher because of insurance costs. This added cost may create a financial hardship on the small QF, preventing it from operating in an economical manner.

Additionally, Staff witness Lisa Schwartz testified that the 2005 Legislature in Senate Bill 84 gave the Commission the authority to increase the net metering eligible facility size for PGE and PacifiCorp. *See* Staff/1500, Schwartz/4. In many states, the eligible facility size for net metering is at or above 100 kW. *See* Staff/2101, Dougherty/1-6. If the Commission, as a result of a rulemaking, was to increase the size of net metering facilities to 200 kW, there could be disparate treatment concerning liability insurance requirements for net metering facilities and those for small QFs up to 200 kW. If the size of net metering facilities is increased, a larger net metering facility would not be required to maintain liability insurance, while a smaller QF under a PURPA purchase power agreement would have to show proof of insurance.

As a result of the high cost of insurance as compared to potential revenues, insurance costs would be a barrier to the development and ongoing operations of very small QFs, especially small wind and run of the river QFs. In Staff's rebuttal testimony, there are six illustrative scenarios where the estimated cost of insurance equals or exceeds the possible revenues a small QF would receive under Idaho Power's Oregon Schedule 85. *See* Staff/2600, Dougherty/3. Additionally, the Oregon-allocated liability insurance costs of each of the three electric utilities are all under one percent of Oregon revenue, as compared to small QFs whose insurance costs would range from approximately 6.4 percent to 241 percent of revenue based on Staff's illustrative scenarios. *See* Staff/2600, Dougherty/3. The insurance cost/revenue ratio for a very small QF is most likely restrictive when other operating expenses (e.g., labor, benefits, materials, utility expenses) and interest expenses are added to the total costs that a QF would likely be confronted with in its development and ongoing operations.

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Low risk - Staff witness Jack Breen pointed out that "no utility was able to provide an example where it was liable for damages because of the actions of a QF." *See* Staff/100, Breen/10. Staff was able to substantiate this information from two other sources, the American Wind Energy Association and Bergey WindPower Company. *See* Staff/2100, Dougherty/5-6.

Idaho Power argued in its UM 1129 Opening Brief that it was aware of several instances on its system where QFs have maintained dangerous conditions that *could* have resulted in serious personal injury or property damage.[4] However, Idaho Power failed to provide any information about these instances. Idaho Power also stated that it has received approval from the Idaho Public Utility Commission (IPUC) for 71 QF contracts.[5] The sheer number of QF contracts, coupled with the fact that Idaho Power has been unable to provide an example where it was liable for damages because of the interconnection actions of a QF, indicates a low level of risk resulting from the operations of a small QF. Additionally, the Commission has no records to support Idaho Power's claim about several potential dangerous situations concerning QF interconnections with the Idaho Power system.

In direct testimony, Staff refers to various industry standards that have been issued in recent years that address "islanding," safety, and damage prevention. To date, these standards have not been adopted in the Commission's Oregon Administrative Rules; however, a forthcoming rulemaking docket staff will propose to establish uniform interconnection standards pursuant to the Commission's objectives and requirements in the Energy Policy Act of 2005. *See* Staff/2100, Dougherty/5-6.

In testimony, Staff pointed out that if a claim is made against a QF that does not carry insurance, customers would likely not be paying higher levels for any uninsured losses related to small QFs than they are currently paying in rates. This is because there is no history of reported injuries or liability claims against a QF and also because substantial insurance costs, including

[4] UM 1129 Opening Brief of Idaho Power Company, December 24, 2004, page 14.

[5] UM 1129 Opening Brief of Idaho Power Company, December 24, 2004, page 13.

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uninsured losses, are already included in rates. Additionally, during a rate case investigation, Staff would closely examine any liability related cost resulting from purchases from small QFs to ensure that the utility aggressively pursued the indemnification clauses of the contract. The burden would be on the utility to demonstrate that it pursued the legal remedies in the indemnification clauses.

In addition, multi-state utilities should be required to maintain their current Oregon allocation concerning purchased power for any potential additional expenses that could have been covered by liability insurance.

Actions by Other Jurisdictions - In Order No. 2006 (RM02-12-000), FERC declined to impose a generic insurance requirement on interconnections for small distributed generation resources. In the order, FERC acknowledges that the risk of interconnecting small inverter-based generators is low and adopted the NARUC approach that each party to the interconnection follow state insurance requirements. *See* Staff/2100, Dougherty/10. Additionally, many states do not impose an insurance requirement of small QFs. *See* Staff/2100, Dougherty/11.

Because FERC, in Order No. 2006, has left insurance requirements to the states, many jurisdictions have not placed mandatory insurance requirements on small QFs, and Oregon does not allow utilities to impose additional insurance requirements on net metering facilities, the decision to carry liability insurance for the smallest QFs should not be mandated by the utilities, but be established by each small QF as a business decision according to its needs.

Indemnification – Insurance requirements should also not be placed on QFs under 200 kW because standard utility contracts for QFs up to 10 MW have indemnification language that state 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

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damage.[6] The indemnification clauses, if pursued aggressively by the utilities, are sufficient legal remedies and adequately protect the interest of the utility, its customers, and small QFs.

Although QFs 200 kW or smaller may decide to carry liability insurance because of business needs, insurance coverage should not be mandated by the utilities because of the reasons stated above (potential costs, net metering statute, low risk, actions in other jurisdictions, and indemnification). The small QF should be able to make the business decision, according to its needs, on how much and what type of insurance to obtain.

8. Negotiation parameters and guidelines for "simultaneous sale and purchase" QF contract and (9.) Negotiating "net output sales" for non-standard contracts.

The parties have settled those issues. *See* PPL/408, Griswold/11-12 (Stipulation) and Staff/1800, Schwartz/17-19.

10. Further exploration of Staff's role in the informal dispute resolution of QF contract disputes. Related to that issue, what is the role of the Commission in dispute resolution during contract negotiations and during the term of the power purchase agreement?

Staff recommends the Commission continue its policy that restricts staff from informal involvement in dispute resolution. Staff can provide some assistance in the negotiation of non-standard contracts by providing information about statutes, answering questions about the consistency of a proposed action with administrative rules, and providing interpretation of approved tariffs and Commission orders. However, staff remains concerned that going beyond this level of assistance would compromise the appearance of its objectivity in the event a QF files a formal complaint with the Commission over contract negotiations, or in rate case disputes over utility administration of QF contracts. Only the Commission's formal complaint process provides the appropriate, open forum for reviewing QF contract disputes. *See* Staff/1800, Schwartz/35-36.

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[6] Indemnification language for QFs up to 10 MW is stated in PacifiCorp's PPA Section 12; Idaho Power's PPA Section XI, 11.1; and PGE's Schedule 201, Qualifying Facility Power Purchase Information, Section 11.

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11. Should competitive bidding be used to set pricing for Qualifying Facilities greater than a certain size (e.g., larger than 100 MW) if the utility has recently completed an RFP, or a bidding process is in progress or imminent? If so, how?

PacifiCorp proposed this issue in Docket UM 1182 (competitive bidding). The issue was subsequently moved to this proceeding.

Conceptually, staff agrees with PacifiCorp that competitive bidding could be used to set pricing for QFs larger than 100 MW. In fact, the Commission envisioned the potential for doing so in its 1991 order on competitive bidding. *See* Order No. 91-1383, Appendix II. To the extent that recent utility RFPs have informed the proxy plant characteristics and costs used in avoided cost filings, competitive bidding may already have been used to inform avoided cost rates based on the utility proxy plant.

Using competitive bidding *directly* for setting avoided costs for cogeneration QFs over 100 MW[7] during the resource deficiency period may be reasonable. However, it raises issues related to timing and type of RFP that would be used, which winning bid(s) to use as the basis for negotiations, and having different avoided cost methodologies for large vs. very large QFs. *See* Staff/1800, Schwartz/40-43.

Competitive bidding should *not* be used to determine avoided costs during the resource sufficiency period. The appropriate avoided costs during that period are on- and off-peak forward market prices in the utility's approved utility avoided cost filing. *See* Order No. 05-584 at 28; Staff/1800, Schwartz/41.

Staff finds unreasonable PacifiCorp's proposal to provide no capacity payment to QFs larger than 100 MW unless the utility selects them through an RFP process. *See* PPL/404, Griswold/24-25; PPL/407, Griswold/2. PacifiCorp states that if it is not in the midst of a competitive bidding process, it is in a capacity-sufficient position, and therefore it would not be prudent to acquire and pay for capacity. *See* Staff/2301, Schwartz/10-11.

[7] PURPA limits small power production facilities such as wind plants to 80 MW or less; there are no size limits for cogeneration facilities under PURPA.

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The company confuses the issue. The utility likely will be resource-deficient at some point over the QF contract term. Therefore, the company will need capacity resources beyond those it acquired in its latest RFP.

Further, providing no capacity payment to QFs larger than 100 MW unless the utility selects them through an RFP process would run counter to previous Commission decisions. The Commission determined in Phase I of this proceeding that QFs have capacity value even during the utility's resource sufficiency period, and that forward market prices appropriately reflect both the energy and capacity value of a QF during this period. *See* Order No. 05-584 at 27-28; Staff/1800, Schwartz/43-45. The Commission upheld the utility proxy plant method for determining avoided costs during the utility's resource deficiency period, including the QF's capacity value. Capacity value is included only in on-peak prices, and these prices are based on the QF's value relative to the utility proxy plant with consideration of the FERC adjustment factors in 18 C.F.R. § 292.304(e).

In addition, federal PURPA requires the utility to purchase "any energy and capacity" that is "made available" to it by a QF, at rates equal to the utility's avoided cost. *See* Weyerhaeuser-ICNU/300, Beach/29.

Staff views competitive bidding as a tool to determine the appropriate price for capacity during the utility's projected deficiency period. The utility may make a filing following a competitive bidding process to adjust both its projected resource sufficiency period and to update avoided costs based on bidding results. *See* Staff/2300, Schwartz/19-20.

Weyerhaeuser-ICNU assert that staff has changed its position on frequency of avoided cost filings. *See* Weyerhaeuser-ICNU/304, Beach/14-15. Staff responds that its proposal is consistent with Order No. 05-584, which states (at 29): "We encourage parties to notify the Commission when it may be appropriate to review avoided cost rates between filing deadlines." Further, Oregon's PURPA rules provide that the Commission may allow a utility to file new avoided cost data during the two-year filing period to "reflect significant changes in

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circumstances." *See* OAR 860-029-0080(7). As Weyerhaeuser-ICNU note, Order No. 05-584 also provides for parties other than utilities to notify the Commission when it may be appropriate to review avoided costs between filing deadlines.

12. Do provisions of the Energy Policy Act of 2005 affect the rules regarding new contracts with Qualifying Facilities? Specifically, should an Oregon electric company be required to enter into a new contract with a Qualifying Facility that is located in the service territory of an electric utility that has been relieved by FERC of a mandatory purchase obligation under PURPA?

This issue was proposed by PGE. Staff concludes that the Energy Policy Act (EPAct) of 2005 requires changes to the Commission's rules related to QFs. Specifically, rules defining eligible cogeneration facilities should be changed to reflect new efficiency requirements, and references to limitations on utility ownership of QFs should be removed. EPAct 2005 also allows a utility to apply to FERC for an exemption from its mandatory purchase obligation under federal PURPA law. Staff concludes that is a matter of federal, rather than state, jurisdiction. Therefore, the Commission need take no action. However, it may wish to modify its rules to recognize the federal provision for a utility to receive such an exemption. *See* Staff/1800, Schwartz/38. Staff will propose rules following conclusion of this docket.

13. Is it appropriate to consider the effect of debt imputation issues resulting from new accounting rules on avoided costs, and if so, how?

Staff recommends the Commission not allow a utility to include in its avoided cost calculations the alleged additional cost a utility incurs for increasing the equity component of its capital structure to "balance" the alleged "debt costs" (i.e. imputed debt) arising from the use of QF "purchase power agreements" (PPAs). Staff makes its recommendation for two primary reasons: (1) there is no reliable method to quantify the alleged impact of a PPA 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. *See* Staff/2000, Morgan/5-11; Staff/2500, Morgan/3-13.

As to the first point, a utility may have multiple PPAs with varying maturities and contract terms. Further, there are many variables that impact a utility's risk and,

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correspondingly, its cost of equity. Thus, quantification of the impact of a PPA on a utility's cost of equity necessarily involves a comprehensive analysis of the many costs, risks and benefits that comprise a utility's capital structure. Staff/2000, Morgan/5-7.

A utility's cost of debt is calculated using its embedded costs. As such, unless a utility issued a new debt instrument as a result of a PPA, there is no reason to assume its embedded cost of debt would change. Staff/2000, Morgan/6.

Simply stated, a utility's cost of equity is derived from a sample group of comparable companies, which presumably also operate with PPAs. As such, like the cost of debt, it is difficult to accept that a particular utility's cost of equity must increase as a result of a specific PPA. Staff/2000, Morgan/7.

Finally, staff observes that if a utility could ever show a direct, definitive impact of a PPA on its cost of capital, the utility could always raise this as an issue in its next rate case. Staff/2000, Morgan/10. *See also* Weyerhaeuser-ICNU/300, Beach/17-19; Weyerhaeuser-ICNU/304, Beach/9-13.

14. How shall the standard form contracts for off-system QFs of PacifiCorp and PGE address where title to the power changes hands? Development of terms for standard off-system QF contracts, and development of negotiation parameters and guidelines for nonstandard off-system QF contracts to address issues related to the transfer of title to off-system power.

Except for the matter discussed under Issue 3(b), the parties have settled all areas of dispute under this issue. *See* Staff/2200, PPL/405, PPL/406 and PPL/409.

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IV. Conclusion

For the reasons stated, the Commission should adopt staff's recommendations for all remaining disputed issues.

DATED this 7th day of June 2006.

Respectfully submitted,

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Attachment A

Staff's Proposed Guidelines for the Negotiation of QF Power Purchase Contracts (QFs 10 MW or Larger)

Contract Length

1. QFs have the unilateral right to select a contract length of up to twenty 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.

Firm versus Non-Firm Commitments

2. The QF should be considered as providing firm power if sanctions for noncompliance in the contract provide energy or capacity pursuant to a legally enforceable obligation for the delivery of a specified amount of energy or capacity over a specified term.

3. An "as available" obligation for delivery of energy and capacity should be treated as a non-firm commitment.

4. 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 utilities' partial requirements tariffs as guidance.

5. A firm QF should be required to make best efforts to meet its capacity obligations during utility system emergencies.

6. A utility may negotiate scheduling requirements for deliveries from a firm QF.

7. For wind and run of the river hydro projects under a firm supply commitment, the utility and the QF should negotiate whether to incorporate a Mechanical Availability Guarantee. Contracts for non-firm supply commitments should not include a Mechanical Availability Guarantee.

Calculation of Avoided Costs

8. For QFs larger than 10 MW, Idaho Power may use the modeling methodology approved by the Idaho Public Utilities Commission for calculating avoided costs for large QFs. However, the Company must incorporate stochastic analysis of electric and natural gas prices, loads, hydro and unplanned outages. The avoided costs determined through this modeling method serve as the starting point for negotiations instead of the filed 20-year avoided costs for standard QF contracts. Unless specifically excluded, Idaho Power must comply with all other requirements set forth by the Oregon Commission for negotiating PURPA contracts and avoided cost rates with large QFs.

9. For PacifiCorp and Portland General Electric, the yearly avoided costs approved for the 20-year period serve as the starting point for negotiations for firm QFs.

10. Any net costs or benefits of the QF, relative to the proxy plant data in the utility's approved avoided cost filing, and as approved for consideration by the Commission in adjusting avoided costs, should be taken into account in negotiating avoided cost rates. The utility may not make adjustments to standard avoided cost rates other than those approved by the Commission.

11. A QF that provides energy or capacity on a legally enforceable basis over a specified term can choose, prior to the beginning of that term, avoided cost rates based on either (i) the avoided costs at the time of delivery; or (ii) the avoided costs calculated at the time the obligation is incurred. A QF that provides energy and capacity on an "as available" basis must receive payments based on the utility's avoided costs calculated at the time of delivery.

12. When avoided cost rates are based on the avoided costs at the time of delivery, the utilities should use current market prices.

13. [*Applicable to PacifiCorp and PGE only*] Adjustments to avoided costs for dispatchability should be made only during the utility's resource deficiency period, when avoided costs are based on the dispatchable utility proxy plant. Adjustments should be made as follows:

    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 availability of the proxy utility 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 an 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. Each utility must include such a model in its compliance filing for this docket.

    d. The utility should use stochastic modeling under various futures, such as that used in Integrated Resource Planning, to address the reduced value of a "24-7" natural gas-fired combined heat and power facility, relative to the dispatchable utility proxy plant.

14. A utility may de-rate a QF's capacity if it falls below the contracted level until the QF can demonstrate its ability to provide a higher level of capacity. However, such a

provision should not prevent the utility from seeking damages in the event market prices during the non-performance period are higher than the QF contract price, and reduced payments to the QF for reduced availability are insufficient to keep the utility whole.

15. Dispatchable QFs should receive fixed capacity payments (in dollars per kilowatt-year) that are tied to performance during the utility's peak period and that reflect the avoided capacity costs of the utility proxy plant.

16. The utility may negotiate fixed pricing per megawatt-hour for QFs relying on intermittent resources.

17. The utility may use its resource planning or production cost models to assess the aggregate value of QFs on the utility's system. However, the QF should receive no more of the aggregate value than the incremental value it contributes.

18. The utility may use its resource planning or production cost models with stochastic parameters to determine the value to the utility system of smaller capacity increments and shorter lead times.

19. If avoided costs during the utility's resource deficiency period are based on a natural gas-fired proxy plant, avoided cost rates for renewable resource QFs, and combined heat and power QFs that are more efficient than the utility proxy plant, should reflect avoided natural gas-price risk to the extent avoided costs are not based on market index prices.

20. QFs with lower line losses relative to the utility proxy plant should receive an additional avoided cost payment based on the utility's line loss studies. Conversely, a QF with higher line losses relative to the utility proxy plant should receive a lower avoided cost payment.

21. 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.

22. 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.

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

24. 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 through its resource planning and acquisition processes. 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. The utilities are prohibited from using a long-range planning target for wind resources as the basis for integration costs.

25. Energy deliveries in excess of the amount committed in the QF contract should be valued at the non-firm off-peak market price.

26. For off-system QF contracts, energy deliveries in excess of the QF's net output that are not offset during the settlement period should be valued at the non-firm off-peak spot price.

27. A utility may not adjust avoided cost rates based on its determination of the additional cost it would incur for increasing the equity component of its capital structure due to the debt a rating agency might impute for QF purchase power agreements.

Avoided Cost Pricing for QFs over 100 MW

28. For QFs larger than 100 MW, competitive bidding may be used as a tool to develop the appropriate avoided cost rates during the utility's resource deficiency period. However, a utility is prohibited from determining a QF provides no capacity value simply because the utility did not select it through a competitive bidding process. Competitive bidding should not be used to determine avoided costs during the resource sufficiency period.

Pricing Options

29. Utilities are not required to offer QFs larger than 10 MW the natural gas index or market pricing options made available to smaller QFs under Order No. 05-584 (at 34-35). However, the utilities and QF may negotiate such pricing options.

Default, Security, Termination and Damages

30. 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.

31. 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.

32. 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.

33. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination or related damages.

34. 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.

35. 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.

Other Requirements

36. Regarding Surplus Sale and Simultaneous Purchase and Sale:[1]

(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

[1] "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. Under a "simultaneous purchase and sale" the QF and the purchasing utility enter into two separate transactions.

(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.

37. [*Applicable to PacifiCorp and PGE only*] The utility should explain in writing the reason for any modifications of standard avoided cost rates when it is negotiating QF contracts.

38. The utility should not impose terms and conditions beyond what is standard practice for the utility's other power transactions. The Edison Electric Institute master agreement should serve as a guide in negotiating QF agreements. However, the QF's unique project characteristics should be taken into account.

39. The utilities can negotiate ownership of the QF's Tradable Renewable Certificates and associated payments. However, the total contract cost that goes into rates for PGE and PacifiCorp must not include the "above market" costs of new renewable resources. The utility should consider the value of owning the Tradable Renewable Certificates to mitigate the risk of potential Renewable Portfolio Standard requirements in the future.

40. Utilities should provide draft and final power purchase agreements according to the following timelines and include these timelines in tariffs for large QFs:

    a. The Company will provide a draft power purchase agreement to the QF within 15 business days of receipt from the QF of all information required to enter an agreement, as specified in the tariff.
    b. The Company will respond within 15 business days to any written comments and proposals the QF provides in response to draft agreements.
    c. The Company will provide a final draft agreement to the QF within 15 business days of the Company's receipt of any additional or clarifying project information needed.
    d. The Company will provide a final executable agreement to the QF within 15 business days of parties' full agreement on the terms and conditions of the draft agreement.

CERTIFICATE OF SERVICE

I certify that on June 7, 2006, I served the foregoing upon all parties of record in this proceeding by delivering a copy by electronic mail and by mailing a copy by postage prepaid first class mail or by hand delivery/shuttle mail to the parties accepting paper service.

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