CHRISTA BEARRY
Legal Administrative Assistant
cbearry@idahopower.com

April 29, 2013

VIA ELECTRONIC FILING AND U.S. MAIL

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Re: Docket UM 1610
In the Matter of Public Utility Commission of Oregon Investigation into Qualifying Facility Contracting and Pricing

Dear Filing Center:

Enclosed for filing in Docket UM 1610 are an original and five (5) copies of the Reply Testimony of M. Mark Stokes on behalf of Idaho Power Company. Copies of the testimony have been served on all parties to this proceeding as indicated in the Certificate of Service.

If you have any questions, please do not hesitate to contact the undersigned.

Sincerely,

Christa Bearry

Christa Bearry
Legal Administrative Assistant

Enclosures

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

Idaho Power/400
Witness: M. Mark Stokes

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UM 1610

IN THE MATTER OF PUBLIC UTILITY)
COMMISSION OF OREGON)
INVESTIGATION INTO QUALIFYING)
FACILITY CONTRACTING AND PRICING)
)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

M. MARK STOKES

April 29, 2013

Q. Please state your name and business address.

A. My name is M. Mark Stokes and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same M. Mark Stokes who previously testified in this docket?

A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/200.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to reply to the testimony filed by Staff and Intervenors on March 18, 2013.

Q. What areas or issues will you discuss in your testimony?

A. My testimony begins with a discussion of several general policy issues that have arisen in this case. Then, I address Idaho Power Company's ("Idaho Power" or "Company") positions with respect to the eligibility cap for standard contracts, the methodology for determining both negotiated and standard avoided cost prices, wind integration charges, the standard contract length, mechanical availability guarantee, and the process and timing of updating standard avoided cost prices.

I. GENERAL POLICY ISSUES

Q. Parties are critical of Idaho Power in this case for allegedly proposing to "dismantle the system created in UM 1129 and UM 1396."[1] Do you agree that Idaho Power's proposals in this case are intended to "dismantle" Oregon's current implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA")?

A. No, I do not. Idaho Power seeks modifications to the Public Utility Commission of Oregon's ("Commission") implementation of PURPA in order to create a system that

[1] RNP/100, Lindsay/4; CREA/200, Reading/4 ("Idaho Power advocates a radical departure from the current method of calculating avoided costs in Oregon.").

more accurately reflects the true avoided costs of a utility through changes to the contract process and avoided cost methodologies. The prices a utility pays for purchases under PURPA are to be just and reasonable to consumers and in the public interest.[2]

The Company's requests in this docket (and in various filings leading up to this docket) have been driven primarily by the fact that the Company believes, and the evidence presented unequivocally demonstrates, that customers are harmed by avoided cost prices that do not accurately reflect the actual avoided cost of Idaho Power. PURPA mandates that customers remain indifferent to Qualifying Facilities' ("QF") generation, which is precisely why the statute requires that the price paid to QFs cannot exceed the utility's avoided cost. The current methodologies used by Idaho Power to determine avoided cost prices for Oregon QFs result in prices that exceed the Company's actual avoided costs, to the detriment of customers and in violation of PURPA. The Company's proposals are intended to introduce elements to the Commission's implementation of PURPA that will result in a more accurate calculation of avoided cost prices.

As mentioned in my Direct Testimony, I would also add that this docket and the Company's requests are timely because PURPA development in Idaho Power's Oregon jurisdiction is increasing.[3]

Q. Has the Company seen any other evidence of growing QF development in Oregon?

A. Yes. Idaho Power is in the process of finalizing standard contracts for four 10 megawatt ("MW") wind QFs.

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[2] 16 U.S.C. § 824a-3.

[3] Idaho Power/200, Stokes/48.

Q. How significant is 40 MW of QF generation in comparison to the customer loads in Idaho Power's Oregon service territory?

A. Idaho Power's average total Oregon customer load in 2011 was 87 MW; therefore, 40 MW of new wind generation represents 46 percent of the Company's total Oregon average customer load, based on nameplate capacity. By comparison, in the Company's Idaho jurisdiction, the ratio of QF wind projects to average total customer load is 573 MW compared to 1,771 MW of Idaho average customer load, which amounts to 32 percent.

Q. The Company focuses much of its Direct Testimony on the impact of wind QFs on Idaho Power's system. Dr. Don Reading, witness for the Community Renewable Energy Association ("CREA"), claims that customers are not harmed by wind development because wind acts as a valuable hedge against future gas market prices.[4] Do you agree?

A. No, I do not. Regardless of the resource type, a QF contract with a fixed price schedule shifts market price risk from the QF project entirely onto Idaho Power's customers. By locking in a single fixed price or a schedule of fixed prices, PURPA projects are hedging the variable market value of the energy for the fixed prices contained in the contract, at the expense of Idaho Power's customers.

In addition, as shown in Idaho Power's wind integration study, at higher wind penetration levels, natural gas resources must be running in order to provide the operating reserves necessary to integrate wind generation. Under this scenario, wind generation will not entirely displace natural gas resources and therefore there is no hedge against future gas market prices.

[4] CREA/200, Reading/7-8.

Q. Dr. Reading also testifies that Idaho Power's claims of customer harm are overstated because the Company's own resources also cost more than market.[5] How do you respond to this argument?

A. Dr. Reading references a chart on page 15 of my Direct Testimony that shows the difference between what Idaho Power's customers have paid and are forecast to pay for PURPA generation compared to market prices. This chart illustrates the cost associated with the fact that utilities must purchase the energy from a PURPA project for the full term of the contract at the pre-established prices regardless as to the utilities' need for energy or the market value of the energy.

A key underlying element that Dr. Reading appears to overlook in his comments is the fact that a utility must take PURPA energy that is supplied to the utility regardless as to the utility's need and/or the cost of alternative energy is a significantly different energy product compared to a utility resource that the utility has full dispatch capability for both need and economics. On page 7 of his Direct Testimony, Dr. Reading is correct in his assumption that "rate base" or fixed costs are not considered in the economic dispatch decision. He is incorrect in stating that fuel costs are not considered. Fuel costs are a component of the variable operating cost and are included in the economic dispatch decision.

Q. Several parties also propose that all three Oregon utilities use the same methodologies to determine their avoided cost prices. Do you agree?

A. No. Avoided cost prices are intended to hold utility customers indifferent.[6] Because each Oregon utility is differently situated from an operational and regulatory perspective, it is reasonable for the Commission to allow each utility to calculate its

[5] CREA/200, Reading/7.

[6] *See* 18 C.F.R. § 292.101(b)(6).

avoided cost prices in a manner that will be the most accurate for that utility. However, it makes sense that methodologies between neighboring or similarly situated utilities would be similar.

Q. What do you mean when you say that each utility is differently situated?

A. As set forth on page 6 of my Direct Testimony, Idaho Power has significantly greater QF development on its system than either PacifiCorp or Portland General Electric Company ("PGE") (both in terms of nameplate capacity and proportionally to its customer base) and for that reason Idaho Power is differently situated than either PacifiCorp or PGE. This QF development has created operational strains on Idaho Power's system that are not necessarily present on the systems of PacifiCorp or PGE and Idaho Power's customers are bearing the costs.

Q. What other differences support Idaho Power's requests in this case?

A. One significant difference between Idaho Power and the other utilities in this case is the fact that Idaho Power's service territory is located predominantly in Idaho and subject to the jurisdiction of the Idaho Public Utilities Commission ("IPUC"). Idaho Power has requested that the Commission allow the Company to use methodologies and procedures in Oregon that are similar to those employed by the Company in its Idaho jurisdiction. Allowing Idaho Power to use similar methodologies in both jurisdictions will decrease the likelihood of litigation caused by QFs engaging in regulatory arbitrage across jurisdictions. In the last couple of years, the Company has litigated three different complaint dockets filed by QFs attempting to game the system and take advantage of higher avoided cost prices in Oregon.[7] Consistency across jurisdictions will make these types of cases less likely.

[7] Dockets UM 1552, 1553, and 1572.

Idaho Power's request to use a similar methodology in both Oregon and Idaho is also consistent with Commission precedent going back to Docket UM 1129.

Q. Several parties testify that the Commission should use PURPA to encourage the development of renewable resources.[8] Do you agree that the Commission's PURPA implementation should focus on encouraging the development of renewable resources?

A. No. PURPA certainly does encourage some development of renewable resources because it mandates that utilities must purchase from a QF. However, hand-in-hand with the purchase obligation, PURPA also strictly requires that the prices paid to the QF must be just and reasonable to ratepayers and in the public interest and cannot exceed the utility's avoided cost.[9] It is inappropriate to focus on encouraging the development of PURPA resources without mentioning the corresponding requirement of ratepayer indifference. The fact that Idaho Power's customers must remain indifferent to the QF generation acts as a strict limitation on the use of PURPA to encourage renewables development.

Q. Several parties also claim that PURPA and non-PURPA projects (i.e., utility-owned generation ("UOG") and non-PURPA power purchase agreements ("PPA")) must be treated comparably. For example, CREA witness Dr. Reading testifies that Idaho Power's proposal to use the incremental cost Integrated Resource Plan ("IRP") methodology for negotiated contracts "puts QFs on an unequal footing with the Company's own resources."[10] Are there meaningful differences between UOGs/PPAs and QFs?

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[8] *See, e.g.*, RNP/100, Lindsay/3.

[9] 16 U.S.C. § 824a-3.

[10] CREA/200, Reading/5. *See also* Coalition/200, Schoenbeck/2 (PURPA contract for less than the full life of the resource penalizes QFs relative to UOGs).

A. Yes. QF generation and utility-owned generation are not "like products." Generally speaking, UOGs provide greater value than QF generation.

Q. What do you mean UOGs provide greater value than QFs?

A. First, QF resources are not economically dispatched in the same fashion as utility-owned resources because of PURPA's "must purchase" obligation. A utility is obligated by law to take QF generation, without regard for need, cost, or other options. In contrast, as discussed below, utility-owned generation is only constructed after demonstration of need and is dispatched by utilizing lowest cost resources first.

Second, because a utility-owned natural gas fired combined-cycle combustion turbine generating plant ("CCCT") (which is the proxy resource used to calculate standard avoided cost prices) is dispatchable, it is able to provide operating reserves necessary for the reliable operation of the electrical system. This is particularly important for Idaho Power given the increasing amounts of variable and intermittent generation being added to the system. An intermittent QF generator, on the other hand, increases the amount of operating reserves a utility must have available.

Third, a dispatchable, utility-owned CCCT can be undesignated as a network resource and utilized to source firm, off-system sales, when economical, which benefits customers by offsetting other power supply costs.

Fourth, new utility-owned resources are scrutinized during public regulatory processes as a part of acknowledgment of the Company's IRP and filing for a Certificate of Public Convenience and Necessity ("CPCN"), where the Company must demonstrate to regulators, customers, and other stakeholders that the new resource will be both the least cost resource as well as a used and useful resource. This helps to ensure that any new resource selected is well suited to the electrical system and customer needs. For example, the need for a resource in 2012 like the

Langley Gulch power plant, which has a 330 MW nameplate capacity in the winter and a 300 MW nameplate capacity in the summer, was first introduced and vetted in the Company's 2004 IRP, and subsequently in the Company's 2006, 2009, and 2011 IRPs. In addition, it was subject to a fully contested CPCN proceeding at the IPUC.[11] In contrast, Idaho Power is forced to take whatever QF generation is proposed to it with no regard to customer need, the QF's impact on the reliable operation of Idaho Power's system, or the cost that QF generation imposes on Idaho Power's customers. Idaho Power was obligated to sign 294 MW of QF wind contracts during a two-month period in late 2010 without any evaluation or scrutiny given to whether those resources were needed, or how they would impact customer rates or the reliable operation of Idaho Power's electrical system.

II. ELIGIBILITY CAP

Q. Can you briefly restate Idaho Power's position on the appropriate eligibility cap for a standard contract?

A. Yes. Idaho Power proposes that the Commission continue to require the use of standard avoided cost prices and contracts for QF projects with a nameplate capacity of 10 MW or less for all generation types except for wind and solar. For wind and solar QF projects, Idaho Power proposes that the Commission use standard prices and contracts only for those projects that have a nameplate capacity of 100 kilowatts ("kW") or less, which would allow for calculation of a more accurate avoided cost price for each project and provide consistency between the Company's jurisdictions.

[11] *See* IPUC Case No. IPC-E-09-03.

Q. Parties testify that the primary reason the utilities are proposing a lower eligibility cap is because of the potential for large QFs to disaggregate into smaller units in order to qualify for standard contracts.[12] Do you agree?

A. No, that is certainly not Idaho Power's "primary" reason for its proposal. I agree that lowering the cap will make it much more difficult for large QFs to disaggregate. However, the *primary* reason Idaho Power has proposed a lower eligibility cap is that negotiated avoided cost prices result in more accurate avoided cost prices by taking into account the specific QF's characteristics.

Q. Parties question your claim that negotiated prices are more accurate than standard prices. For example, Staff witness Adam Bless testifies that the model proposed by Idaho Power for determining negotiated prices, the incremental cost IRP methodology, is only as accurate as the forecasts that are input into the model.[13] How do you respond to this criticism?

A. Staff's critique is generally true—any model is only as good as its forecasts. However, Idaho Power's proposed incremental cost IRP method has a significant advantage over the current Standard Method[14] because it is less sensitive to the natural gas price forecast than the Standard Method. Idaho Power has compared the gas price sensitivity of the Surrogate Avoided Resource ("SAR") methodology and Idaho Power's incremental cost IRP methodology. Because the SAR methodology and the Standard Method are similar, this analysis can be applied to the Oregon Standard Method. Both methodologies were used to calculate avoided

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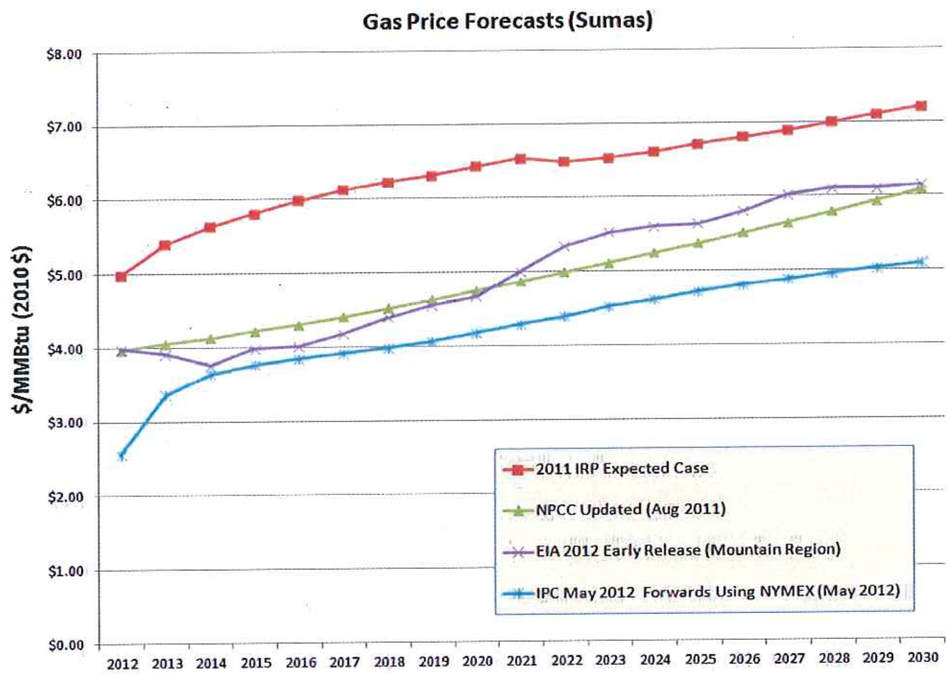
[12] *See, e.g.*, Coalition/100, Lowe/26.

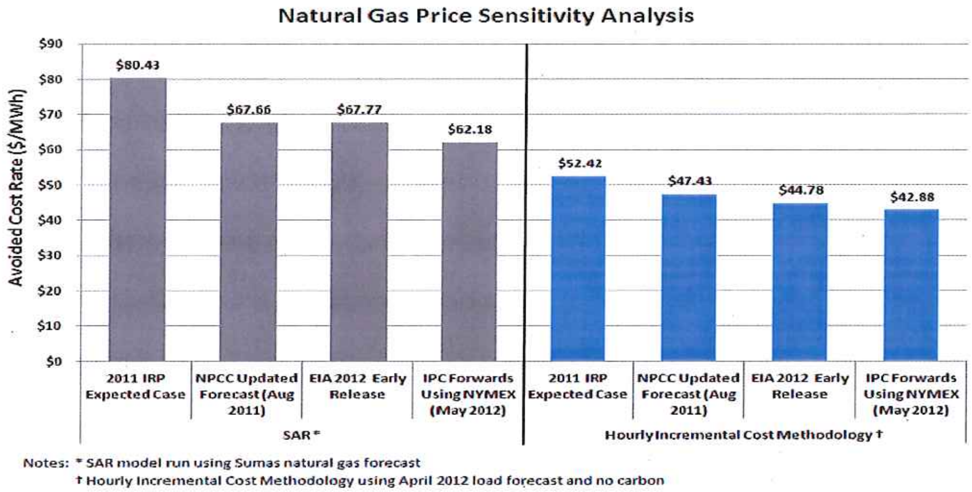
[13] Staff/100, Bless/9.

[14] In my Direct Testimony, I referred to the "Oregon Method" that all three utilities currently use for calculating standard avoided cost prices. Staff's testimony has referred to this method as the "Standard Method." To avoid confusion and to use consistent terminology, in this testimony I will refer to the "Oregon Method" as the "Standard Method."

cost rates for a base load resource using Idaho Power's 2011 IRP natural gas price forecast (August 2010), the Northwest Power and Conservation Council's updated forecast (August 2011), the U.S. Energy Information Administration ("EIA") forecast (January 2012), and current NYMEX forward prices. This series of natural gas price forecasts occurred over a time period where prices were falling and is shown in the following figure.



The results of this comparison are provided in the figure below and show the 20-year, levelized avoided cost rates from the SAR methodology vary from $80.43 to $62.18 (23 percent) and the Hourly Incremental Cost methodology varies from $52.42 to $42.88 (18 percent).



These results show that the SAR methodology is more sensitive to the natural gas price assumption than Idaho Power's proposed Hourly Incremental Cost methodology. Natural gas prices have historically been the most volatile of all the inputs used to set avoided cost rates. Using a methodology that is less sensitive to the gas price forecast will likewise reduce the volatility of avoided cost rates.

I would also point out that even though Staff appeared to question whether the incremental cost IRP methodology resulted in a more accurate avoided cost price, Staff's testimony also made clear that:

> . . . model-based methods account for a greater array of costs associated with the purchase of QF power; specifically those costs avoided by the utility and actual costs incurred by the utility because of specific operating characteristics of the QF. The models take into account the hourly variations in the QFs expected generation and in the utility's load. The models are well established and in fact are the same models that are used to prepare the Integrated Resource Plan. They inherently factor in the different operating characteristics of wind, solar and other QF types. Staff also considered the fact that model-based approaches have already been used for large (> 10 MW) QFs, and are already used in many other states.[15]

[15] Staff/100, Bless/13.

As Staff summarized, the IRP methodology is more desirable because is it more accurate, it takes into account specific characteristics of each QF's project, and it's based upon a well established model that accounts for actual hourly loads.

Q. Parties also claim that the incremental cost IRP methodology lacks the transparency of the Standard Method and that QF developers will be unable to predict changes in avoided cost prices.[16] Do you agree with this critique of the incremental cost IRP methodology?

A. No. The foundation of Idaho Power's proposed incremental cost IRP methodology is the Company's acknowledged IRP. In the process of acknowledging the IRP, the Commission and other parties have the opportunity to review the various model runs, inputs, and other analysis. Because the IRP goes through the acknowledgement process, the basis for this model receives much scrutiny and review. In addition, in the case of specific negotiations for a non-standard QF project, Idaho Power will provide the QF project with proposed indicative avoided cost values in accordance with Schedule 85 and respond to QF questions with regard to the price modeling. If these questions require review of model runs, input data, etc., Idaho Power will provide this data in a reasonable manner in compliance with any applicable confidentiality and software licensing requirements.

Moreover, the AURORA model, which is used to determine the dispatch of utility-owned resources in the incremental IRP methodology, has been used by Idaho Power for years in both the planning and ratemaking processes.

All other information and calculations are done in an Excel spreadsheet, which I believe is very transparent. The main Excel worksheet is large, but only because it performs the same calculation for every hour of the contract term.

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[16] ODOE/100, Carver/5-6.

Q. Renewable Northwest Project ("RNP") witness Jimmy Lindsay claims that developer sophistication and the mismatch between standard and project-specific (i.e., negotiated) avoided costs prices "are unlikely to have changed significantly" since the Commission's orders in Docket UM 1129.[17] Do you agree with Mr. Lindsay's claim?

A. No. First, I would refer back to pages 58 to 63 of my Direct Testimony where I describe in detail the nature of the QF developers that have been contracting with Idaho Power. This testimony demonstrates that the sophistication of many QF developers has increased substantially relative to the assumptions included in the record in UM 1129.

Second, I believe that the overall level of QF development has greatly exceeded the amount anticipated in UM 1129. When viewed in the aggregate, this increased development has compounded the mismatch between standard and negotiated avoided cost prices.

Q. Parties also claim that if the eligibility cap is lowered, it will effectively end PURPA development in Oregon. How do you respond to this claim?

A. In the Company's Idaho jurisdiction, the eligibility cap for wind and solar QFs is set at 100 kW and even with this lower cap, Idaho Power has entered into contracts with additional QF projects, including wind, and continues to receive inquiries. In spite of its potential impacts on development, I believe the Commission's focus should be on ensuring that the avoided cost price accurately reflects the true avoided cost of the utility in order to maintain ratepayer indifference, which is best achieved through negotiated contracts.

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[17] RNP/100, Lindsay/4-5.

Q. Parties argue that if the Commission refines the methodology for calculating the standard prices it will mitigate the need to reduce the eligibility cap.[18] How do you respond to that argument?

A. It is true that developing a more comprehensive methodology for calculating standard prices would somewhat mitigate the necessity for reduced eligibility caps. However, the reverse is also true—if the cap is lowered, it mitigates the potential impacts of standard prices that do not measure a utility's avoided cost prices as precisely as negotiated prices. I believe that negotiated prices are more reflective of the utility's actual avoided costs; therefore, it makes sense to have as many negotiated contracts as possible. Indeed, Staff appears to endorse this thinking with its proposal that the Commission ***either*** refine the calculation of avoided cost prices by including an adjustment for the QF's capacity factor ***or*** maintain the current methodology and lower the eligibility cap to 3 MW. I believe that it is important to refine the calculations for standard prices as well as lower the cap in order to ensure customers are paying an accurate avoided cost price. While there is interplay between these two concepts, I believe it's important that each can stand on its own instead of leaning on one to remedy deficiencies in the other.

Q. Does the Company support Staff's proposal?

A. Keeping in mind concerns over potential problems that may arise by addressing only one of the issues, if the Commission does not adopt Idaho Power's proposal to both lower the eligibility cap for wind and solar QFs and refine the methodology for calculating standard avoided cost prices, then the Company supports Staff's proposal as an alternative to the Company's.

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[18] *See, e.g.*, Coalition/100, Lowe/27.

Q. You testify that the concern over disaggregation is not the primary reason Idaho Power is requesting a lower eligibility cap. Does that mean that Idaho Power agrees that the Commission's current disaggregation policy is effective?

A. No. As stated above, the Company's primary reason for lowering the eligibility cap is to obtain the most accurate avoided cost prices to maintain ratepayer indifference as required by PURPA. Developers' gaming of the Commission's current disaggregation rules eliminates the underlying intent of ensuring that only small, unsophisticated projects receive published avoided cost prices. No matter how comprehensive the Commission's criteria for prohibiting disaggregation may be, if there is financial gain to do so, developers will find a way around it. For example, Idaho Power is about to execute standard contracts for four 10 MW wind projects—called Prospector, Jett Creek, Benson Creek, and Durbin Creek. The same developer is building all four projects and, according to corporate records, the four limited liability companies that will own the four projects were originally organized and incorporated by the same individual. Then, 10 months after incorporation, the organizer designated himself as manager of all four limited liability companies. Ten months later, a different manager was designated for two of the entities. As of today, the four entities have been reorganized and restructured so that the developer and original organizer will own two of the projects—Jett Creek and Durbin Creek—and another entity will own the other two—Prospector and Benson Creek—with no documented common ownership or management.

Prospector and Jett Creek (who have separate owners) are nearly adjacent to one another and Benson Creek and Durbin Creek (who have separate owners) are nearly adjacent to one another. These groupings of two are located approximately 5.7 miles from one another. The developer ensured that the projects meet the Commission's disaggregation criteria and are therefore eligible for standard contracts even though these projects are essentially one 40 MW project. This example demonstrates that whatever the disaggregation criteria may be, savvy developers will find ways to circumvent the rules if there is a significant price difference between avoided costs for standard contracts and negotiated contracts. That is why the reduction in the eligibility cap is the best way to ensure that only those QFs that are intended to receive standard contracts are eligible for standard contracts.

III. NEGOTIATED AVOIDED COST PRICES

Q. Can you briefly restate Idaho Power's position with respect to the negotiation of an avoided cost price for QFs that exceed the standard contract eligibility cap?

A. Yes. Idaho Power proposes no changes to the Company's current Schedule 85, which states that the starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the IPUC for QFs over 10 MW. The modeling methodology approved by the IPUC is the Company's incremental cost IRP methodology (described in detail in my Direct Testimony).

Q. CREA witness Dr. Reading criticizes the incremental cost IRP methodology because it uses a "single run" of the AURORA power cost modeling, which Dr. Reading claims is inconsistent with Federal Energy Regulatory Commission ("FERC") precedent.[19] Do you agree?

A. No. Dr. Reading testifies that "FERC specifically described a 'double-run' methodology as being appropriate when defining avoided costs."[20] However, the

[19] CREA/200, Reading/5-6.

[20] CREA/200, Reading/6.

quoted language simply outlines a double-run methodology as "one way of determining the avoided cost."[21] FERC's recognition of a "double-run" method does not mean that all other methods are unacceptable. Indeed, the "double-run" method was specifically set forth by FERC as an example of "one way" to determine the utility's avoided incremental costs. Whether read in isolation or in context, the quoted language in Dr. Reading's testimony from FERC Order No. 69 cannot reasonably be read as a prohibition on all methods except the double-run method. On the contrary, Idaho Power's proposed incremental cost IRP methodology is tied directly to FERC's definition of avoided cost because it focuses on the incremental cost the utility would incur but for the purchase from the QF.[22]

Q. Parties also challenge the Company's incremental cost IRP methodology because it does not consider the value of potential wholesale power sales.[23] How do you respond to this criticism?

A. As described more fully in my Direct Testimony,[24] the incremental cost IRP methodology is based upon the definition of "avoided cost" in FERC's regulations, which focuses on the incremental costs to Idaho Power that would be incurred but for the QF purchase rather than hypothetical values of potential wholesale power sales. Avoided costs are defined as the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another

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[21] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("Order 69")*, 45 Fed. Reg. 12, 214, 12, 216 (Feb. 25 1980).

[22] 16 U.S.C. § 824a-3.

[23] 16 U.S.C. § 8241-3(d); *See, e.g.,* ODOE/100, Carver/7; CREA/200, Reading/5.

[24] Idaho Power/200, Stokes/35.

source."[25] Revenue from a potential wholesale transaction is not a cost that would have been incurred and is not properly considered under PURPA.

IV. STANDARD AVOIDED COST PRICES

Q. Can you briefly restate Idaho Power's proposal for calculating standard avoided cost prices?

A. Idaho Power proposes that the current Standard Method be adjusted to differentiate prices based upon the type of generation resource that is proposed using that resource's peak-hour capacity factor. This proposal is substantively identical to Staff's proposal for adjusting the Standard Method for determining avoided cost prices.[26]

Q. Renewable Energy Coalition witness Donald Schoenbeck criticizes the Company's method of calculating the factors used to adjust the capacity component of the avoided cost price.[27] Can you describe his argument?

A. Yes. Under the Company's proposal, the capacity component is calculated by multiplying the annual capacity cost[28] by the peak-hour capacity factor of the QF resource. This accounts for the capacity the QF resource will provide during Idaho Power's peak-hour load period between 3:00 p.m. and 7:00 p.m. in July. The Company proposes calculating the peak-hour capacity factor using the 90th percentile exceedance criterion that is used in the Company's IRP. This means that there is a 90 percent probability that the specific resource type will contribute to serve Idaho Power's peak-hour demand.

[25] 18 C.F.R. § 292.101(b)(6).

[26] Staff/100, Bless/4 and 16.

[27] Coalition/200, Schoenbeck/5-6.

[28] This is determined by multiplying the capital costs of a CCCT by the nameplate capacity of the QF and then converting this value to an annual cost by multiplying by 12.

Mr. Schoenbeck takes issue with the use of the 90th percentile exceedance criterion and claims that the Commission should use the average value of capacity deliveries from the resource type, rather than the 90th percentile values.

Q. Why did the Company propose the use of the 90th percentile exceedance value?

A. Use of the 90th percentile exceedance value is consistent with the methodology used by the Company in developing its IRP. Idaho Power's ability to import additional energy is typically limited during peak load periods. Therefore, peak-hour load planning criteria are more stringent than average load planning criteria and the use of the 90th percentile exceedance is reasonable.

Using Mr. Schoenbeck's lower percentile capacity factor increases the probability that planned-on capacity will not be available when needed. Indeed, using the average capacity factor, as proposed by Mr. Schoenbeck, means that half of the time, planned-on capacity would not actually be available during peak hours.

Moreover, calculating the assumed capacity contribution to peak load is consistent with the method used in the Company's acknowledged IRP and will result in less controversy and litigation whenever the standard avoided cost prices are updated.

Q. Does Mr. Schoenbeck make an alternative recommendation?

A. Yes. Although Mr. Schoenbeck makes no recommendation for the "peak-hour capacity factor," he does recommend that the "on-peak" capacity factor for canal drop hydro projects be set at 100 percent.

Q Does Mr. Schoenbeck provide an evidence to support the 100 percent value?

A. No, he does not. And, it is entirely unrealistic to assume that any project will be available 100 percent of the time.

Q. Is there a difference between the "on-peak capacity factor" proposed by Mr. Schoenbeck and the "peak-hour capacity factor" proposed by Idaho Power?

A. Yes. "On-peak" is typically a reference to heavy load hours (16 hours a day), whereas "peak-hour" specifically identifies a unique hour within the heavy load hours when the utility encounters peak customer loads. As noted above, in the case of Idaho Power, this "peak-hour" typically occurs between the hours of 3:00 p.m. and 7:00 p.m. in the month of July. The capacity factors used within the Standard Method reflect the "peak-hour" capacity factor and not the "on-peak" capacity factor. It is this "peak hour" capacity that the utility avoids by the addition of a QF facility.

Q. Does Mr. Schoenbeck have any other criticisms of Idaho Power's approach?

A. Yes. Mr. Schoenbeck also takes issue with the samples used by Idaho Power to determine the capacity values.[29] Mr. Schoenbeck claims that Idaho Power's proposed value for hydro projects was derived from a sample of only four utility-owned QFs and used only four years of data from these projects.

Q. Are these criticisms valid?

A. Not entirely. First, contrary to Mr. Schoenbeck's implication, Idaho Power does not own any QF resources. The data used by Idaho Power was from four QFs that are not owned by Idaho Power. Second, in making its initial recommendation for peak-hour capacity factor, Idaho Power relied on hourly data for a group of projects where the hourly data was readily available. This approach was consistent with the analysis relied on by the Company in the general PURPA proceeding before the IPUC. However, as Mr. Schoenbeck stated, since the Company's Direct Testimony was filed in this case, the IPUC conducted a more thorough analysis of a much

[29] Coalition/200, Schoenbeck/6.

larger sample of hydro projects using hourly meter data.[30] Idaho Power concurs with the IPUC Staff's analysis, which resulted in a canal drop hydro project annual capacity factor of 32 percent and peak-hour summer capacity factor of 79 percent, and a non-canal drop hydro project annual capacity factor of 50 percent, and peak-hour summer capacity factor of 67 percent.

Q. Did any other witnesses address the use of a peak-hour capacity factor to adjust standard avoided cost prices?

A. Yes, Mr. Bless proposed a substantively identical method as the Company.

Q. Did Mr. Bless specifically refer to a "peak-hour capacity factor" in his testimony?

A. No. Mr. Bless refers to the "capacity contribution factor" and goes on to define the capacity contribution factor as the expected contribution to peak load of the specific QF resource type. The assumed capacity contribution to peak load is the same one used in the utility's acknowledged IRP for the specific type of generation.[31] As stated above, the IRP uses the "peak-hour capacity factor" and therefore it appears that Staff is referring to the same value as the Company, even though the terminology is slightly different.

Q. Oregon Department of Energy ("ODOE") witness Phil Carver testifies that the "[e]lectric companies have not provided evidence of fundamental market

[30] Calculation of some QF resource peak hour capacity factors is one of the issues under reconsideration in that case. *See* IPUC Case GNR-E-11-03, Order No. 32737. In the Idaho case, the IPUC staff extensively analyzed a much larger sample of Idaho Power QF hydro projects using hourly meter data. *See* GNR-E-11-03, Comments of the Commission Staff (March 25, 2013). The Company reviewed the IPUC Staff analysis and concurred in its results.

[31] Staff/100, Bless/23.

changes in power operations or market dynamics to justify a change to a more complex modeling method."[32] How do you respond to Mr. Carver's critique?

A. Idaho Power's proposed changes are not driven by market dynamics, but driven by the fact that the current Standard Method is not an accurate calculation of a utility's avoided cost. PURPA requires that the avoided cost be just and reasonable to consumers and in the public interest and should hold ratepayers indifferent. Changes in market dynamics are not necessary to establish that the current method is inaccurate. What is important is that Idaho Power has demonstrated that the currently established avoided costs are inaccurate. Using a CCCT to develop an avoided cost price for a wind project without taking into account the capacity factor differences between the two projects will result in a less accurate estimated avoided cost price. This is true in today's market and it was true when the Commission adopted the Standard Method in Docket UM 1129. However, when the method was adopted in UM 1129, it was done with the assumption that development would not occur in the quantities that it has. When viewed in isolation, small inaccuracies in the avoided cost prices in the standard method are not as troubling. When viewed in the aggregate and when taking into account the large amount of PURPA on Idaho Power's system, the cumulative effect of these inaccuracies leads to a situation where ratepayers are significantly impacted by inaccurate avoided cost prices.[33]

Moreover, I disagree with Mr. Carver's argument that the methodology for calculating the avoided cost price should be determined by current market dynamics. The market will change over time and therefore the goal of developing an avoided cost methodology is to develop one that works ***regardless*** of the market dynamics.

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[32] ODOE/100, Carver/2.

[33] Idaho Power/200, Stokes/14-20.

As a factual matter, I also disagree with Mr. Carver's claim that power operations have not changed since UM 1129. As detailed in my Direct Testimony, the influx of wind on Idaho Power's system, which is largely the result of PURPA projects, has caused the Company to incur substantial integration expenses that are being paid by customers, not QFs.

Q. Dr. Reading testifies that Idaho Power's proposal to account for capacity factors when determining the standard avoided cost prices is unnecessarily complex and will cause confusion because PacifiCorp and PGE have not made such a request.[34] Do you agree?

A. No, not at all. Idaho Power's proposal—which is simply to multiply the capacity component of the avoided cost price by a predetermined capacity factor value approved by the Commission—is straightforward. Moreover, I would point out that until this year Idaho Power has used a different methodology than PacifiCorp and PGE and there is no evidence that doing so has caused confusion among QF developers. And, in any event, his concern may be moot because Staff has advocated that all three utilities adjust their standard avoided cost prices to account for capacity factors in a manner that is nearly identical to Idaho Power's request.

Q. Dr. Reading also claims that QFs must have access to levelized prices or else they may have trouble obtaining financing for their projects.[35] Has Idaho Power seen evidence that the lack of levelized pricing in Oregon has limited QF development?

A. Not at all. As I have already mentioned, the Company has seen extensive interest in Oregon contracts despite the fact that there is currently no option for levelized

[34] CREA/200, Reading/4.

[35] CREA/200, Reading/9.

pricing.[36] Over the last 13 years, Idaho Power has executed 51 PURPA contracts and only five have elected to use levelized prices. As I discussed in Direct Testimony, levelized price long-term contracts are harmful to customers and appear to be unnecessary for developers.

Q. Several parties have requested that when an existing QF's contract expires during a period when the utility is resource sufficient, the QF should receive a capacity payment if it chooses to enter into a new PURPA contract.[37] Does Idaho Power support this proposal?

A. Yes. The IPUC recently adopted a similar policy. Therefore, in the interests of consistency, and to discourage regulatory arbitrage, Idaho Power supports the proposal for Idaho Power.

Q. Dr. Reading claims that when all QFs on Idaho Power's system are considered together "they provide a fairly predictable supply of power to the system. . . ."[38] Does Idaho Power's experience support Dr. Reading's proposition?

A. No. Dr. Reading is correct that for its IRP, Idaho Power creates and uses a monthly forecast of all QF projects for purposes of long-term planning. However, Idaho Power must also operate the electrical system on a real-time and hourly basis and QF generation is not reliable on a real-time or hourly basis. QF projects are not required to provide Idaho Power any guaranteed hourly generation. Rather, QFs provide energy whenever they are capable of doing so. Performance guarantees, such as a mechanical availability guarantee, incorporate monthly performance requirements into a PURPA contract, yet they still provide no assurance of a QF

[36] Idaho Power/200, Stokes/74-77.

[37] *See, e.g.,* Coalition/100, Lowe/21.

[38] CREA/200, Reading/23.

project's energy delivery in any given hour during the month, let alone in real time. The real-time and hourly operations of the electrical system must meet a higher standard than "fairly predictable" in order to provide safe and reliable service to its customers.

Q. Several parties propose an additional adjustment to the standard avoided cost prices to account for avoided transmission expenses.[39] Does Idaho Power support these adjustments?

A. No. For Idaho Power, this type of adjustment is unnecessary because all parties in this case have assumed a theoretical CCCT proxy unit would be in Idaho Power's service territory and therefore there is no avoided transmission expense associated with an off-system proxy resource. Idaho Power agrees with this assumption because there appears to be numerous viable sites and Idaho Power assumes the costs of an on-system plant are less than a comparable off-system plant.

Moreover, if the Commission decides to account for the avoidance of these transmission expenses, the Commission must also account for additional transmission expenses that may be incurred because of a QF. This is particularly true during the sufficiency period when the utility is forced to take the QF energy and due to other electrical system operational and reliability issues is unable to shut down other utility generation, thus creating surplus energy that must be sold into the market that is a direct result of the utilities must-take obligation associated with the QF energy. To sell this surplus energy at market, the utility now incurs a transmission cost to move the utilities surplus energy to market regardless as to the economics of the transactions. This transaction is a direct result of the QF project providing energy to the utility when the utility had no need for the energy. None of

[39] *See, e.g.*, OneEnergy/100, Eddie/22.

these transmission or transaction costs are currently accounted for in the standard avoided cost calculations.

Q. Some parties argue that QFs should receive a credit for allowing utilities to defer expenditures on new capacity.[40] These parties rely on PacifiCorp's calculation of the benefit attributable to deferred expenditures on new capacity resulting from demand-side management ("DSM") programs. Do you agree that QFs should be compensated for allowing utilities to defer capacity expenditures?

A. No, I do not. QFs already receive a capacity credit during a utility's resource deficiency period. In the near term, when a utility is resource sufficient and does not need capacity, it makes no sense to pay QFs for their capacity contributions.

In addition, due to the long lead time required to construct a utility-scale resource, even during the sufficiency period, a utility is likely already engaged in the process of planning for and acquiring its next resource. From a practical standpoint, the addition of unplanned, small QFs does not result in the deferral of new, near-term resources because utilities do not have control over the addition of small amounts of QF capacity and are not able to plan for these additions in the IRP process.

I also believe that the comparison of QFs to DSM programs is inapt because DSM can be reasonably forecast in the IRP process. Moreover, DSM programs are under the control of the utility and can be managed so they delay the need for new utility resources in the near term.

[40] *See, e.g.,* OneEnergy/100, Eddie/10; CREA/200, Reading/25.

Q. Parties also[41] argue that avoided cost rates should be adjusted to account for additional gas pipeline infrastructure necessary to serve the proxy resource and credit QFs for avoidance of this cost. Do you agree?

A. No, I do not. A vast majority of the QF resources Idaho Power has under contract, and is likely to contract with in the future, are variable and intermittent and provide only a small fraction of the peak-hour capacity provided by the proxy resource. It would be inappropriate to credit QF resources for this through avoided cost rates based on the energy they provide, when the utility's need for new resources is driven by capacity needs.

Additionally, this proposal would create the need for assumptions for the location of the proxy simple-cycle combustion turbine ("SCCT") resource, which would be different for each utility. In Idaho Power's case, the calculation would also need to take into consideration that existing summertime pipeline capacity is much greater than it is in the wintertime when the pipeline is more fully utilized for heating homes and businesses. Finally, each QF resource type would only be given credit for the fractional share of peak-hour capacity provided when compared to the SCCT proxy resource. Ultimately, I believe this would be a very small amount.

Q. OneEnergy, Inc. ("OneEnergy") witness Bill Eddie also requests different treatment for QFs that connect to a utility's distribution system and are less than 3 MW. Do you believe that these types of QFs should receive special treatment?

A. No. PURPA and its implementing regulations do not provide for different or special treatment for QF projects based upon whether the interconnection occurs on the

[41] OneEnergy/100, Eddie/22; CREA/200, Reading/23.

distribution or transmission electrical system. The utility's avoided cost as defined by FERC is the same regardless of the interconnection point of the QF.

V. WIND INTEGRATION CHARGE

Q. Can you briefly restate Idaho Power's position with respect to the imposition of a wind integration charge?

A. Yes. Idaho Power proposes to implement a wind integration charge for any wind QF contracting with the Company.

Q. Has Idaho Power proposed a similar integration charge for solar QFs?

A. Not at this time. Idaho Power's proposal addresses only wind QFs. However, upon completion of a solar-specific integration study, Idaho Power believes it would be appropriate to assess an integration charge for solar QFs.

Q. How does Idaho Power propose that the wind integration charge be implemented?

A. Idaho Power supports a proposal described by Staff at the April 2, 2013, settlement conference whereby the Commission would adopt a separate Idaho Power tariff for QF wind integration. This charge would be assessed under separate provision of the standard contract and would not be netted against the standard avoided cost price.

Q. Mr. Lindsay claims the utility's wind integration studies are not designed to measure the cost of wind integration specifically for wind QFs.[42] Do you agree?

A. No, I do not. Idaho Power's study includes the Company's entire fleet of wind resources (a fleet with a nameplate capacity of 678 MW as of January 2013). However, in Idaho Power's case, the fleet consists of only one non-QF project, the 101 MW Elkhorn Valley wind project in northeastern Oregon. All of the other wind

[42] RNP/100, Lindsay/10.

resources that were modeled for the study are based on existing and projected QF wind projects (the projected QFs were used to reach the higher wind penetration levels analyzed in the study).

I would also like to comment on the distinction Mr. Lindsay draws between "very large, utility-scale" wind projects and QF projects. It should be noted that Idaho Power is currently integrating the 79 MW Rockland wind project in eastern Idaho, which sells wind energy to Idaho Power under a QF contract.

In addition, the integration costs are driven more by the total installed wind capacity on Idaho Power's system than by the capacity of any one particular project.

Q. Mr. Lindsay also claims that wind integration study methodologies have changed dramatically from study to study, which has resulted in large changes in the calculated reserve requirements and wind integration costs.[43] Do you agree?

A. No. Indeed, the basic framework of the Idaho Power study has remained unchanged since 2008. Idaho Power's study recognizes that a load-serving entity must operate its dispatchable resources differently when wind is part of its fleet. The study isolates the effects of wind on the operation of the dispatchable resources by looking at two scenarios. First, the study models the operation of dispatchable resources when they are burdened with incremental balancing reserves caused by wind generation. Second, the study runs the same model without the additional balancing reserves. This study design was the model for Idaho Power's first wind integration study, and has remained the model for the second study.

For the Company's latest study, Idaho Power did make one change to allow the model to consider scenarios where integration was not possible. The Company

[43] RNP/100, Lindsay/10.

made this change because Idaho Power's dispatchable resources are not always capable of providing the balancing reserves necessary to integrate wind given the rapid expansion of installed wind capacity on Idaho Power's system. Even with this change, however, the basic framework designed to estimate the costs of modifying the operation of dispatchable resources such that they are ready to respond to wind is unchanged.

Q. Mr. Lindsay recommends updating wind integration studies and costs on the same cycle as avoided cost prices.[44] Do you agree with this?

A. No, especially if avoided cost prices are updated annually as is proposed by most parties in this case. The analytic effort required to update avoided cost prices is not trivial; however, it is not of the same scope and depth as a wind integration study. A study of wind integration involves numerous significant analytic components, which include the derivation of wind production data for future wind build-outs, the calculation of balancing reserve levels associated with the future build-outs, and the detailed system modeling necessary to determine the effects and costs of incremental balancing reserves.

In addition, the Commission has directed Idaho Power to fully engage a Technical Review Committee in the process of studying integration of intermittent renewable generation. As a practical matter, Idaho Power believes that adherence to this directive precludes the possibility of updating wind integration studies on the same cycle as avoided cost prices.

Q. How frequently do you believe wind integration studies should be updated?

[44] RNP/100, Lindsay/11.

A. Generally, I believe that wind integration studies should be updated every three years. Three years is sufficient time to prepare the next study, yet short enough that results are likely to remain relevant between studies.

That said, it may be possible to update wind integration costs on a more frequent basis if the update is limited to updating only the load forecast, natural gas prices, and forward market prices. Under this scenario, future wind build-outs and wind data would remain unchanged from the original study. Also, under this scenario a Technical Review Committee would not be required because the model and methodology would remain unchanged.

It may also be necessary to fully update wind integration studies more frequently based on changes in the Company's installed wind capacity. From a long-term planning perspective, it has been challenging to predict the expansion of installed wind capacity. With the exception of the Elkhorn Valley wind project, which resulted from the 2004 IRP's identification of a utility-scale wind project in the preferred resource portfolio, the wind projects connecting to Idaho Power's system have been developed as QF projects outside of an IRP process. Wind fleet expansion has been characterized by fits and starts, with periods where wind penetration remains fairly stable, followed by periods with very rapid growth. It is difficult to predict whether wind integration studies in the coming years will need to be updated frequently to keep up with rapid wind development when or if it occurs.

Other factors may also trigger the need for an updated study. For example, systemic changes to electric market practices, the implementation of new regional balancing initiatives, significant fuel price changes, or the addition of new generating or demand-side resources, particularly flexible resources providing wind-balancing capability, may all result in the need for a new integration study.

Q. Mr. Lindsay states that IRPs do not generally provide a sufficient forum for scrutiny and specific Commission approval for wind integration studies.[45] Do you agree with this?

A. Yes, I do. The IRP is focused on ensuring that the Company continues to meet customer demand through the development of a long-term resource plan that balances cost, risk, reliability, and environmental concerns. The detailed study of system operations and the effects of wind integration on system operations is largely outside the scope of resource adequacy issues.

Q. Mr. Lindsay is critical of Idaho Power's wind integration study because a Technical Review Committee was not engaged in the study until late in the process when the study was mostly complete.[46] Can you explain why Idaho Power did not form a Technical Review Committee until the study was nearly complete?

A. It was simply an issue of timing. The Company's wind integration study began in the spring of 2011. The Commission directed Idaho Power to form a Technical Review Committee in its February 14, 2012, public meeting (Order No. 12-177 issued May 21, 2012). Thereafter Idaho Power announced the formation of a Technical Review Committee at an April 6, 2012, public workshop. However, by this time in the process, the study was nearly complete and the Company was already presenting preliminary study results.

Idaho Power held regular meetings with the Technical Review Committee following the April 6, 2012, public workshop. In these meetings, a detailed discussion of the study methodology was provided to the Technical Review

[45] RNP/100, Lindsay/12.

[46] RNP/100, Lindsay/14.

Committee. Given the near-completed state of the study at the time that the Technical Review Committee was formed, Idaho Power and the Technical Review Committee members agreed that the primary role of the Technical Review Committee would be to issue comments on the study methodology upon release of the study report.

Q. Mr. Lindsay claims Idaho Power's wind study is flawed because it calculates balancing reserve requirements based on day-ahead schedule errors as opposed to hour-ahead schedule errors.[47] Can you explain the significance of both day-ahead scheduling and hour-ahead scheduling as they relate to wind integration?

A. Yes, I can. In both cases, the issue is uncertainty. Deviations between forecast and actual wind production need to be covered by other resources in order to maintain the balance between supply and demand. Not surprisingly, day-ahead forecasts are more uncertain and therefore deviations are typically larger for forecasts provided day-ahead versus hour-ahead. Thus, the balancing reserve requirements are greater when using day-ahead scheduling.

Q. Why does the Company use day-ahead scheduling to determine its wind integration costs?

A. Idaho Power views the use of day-ahead scheduling as a correct simulation due to system scheduling practices.

The appropriateness of the use of the day-ahead errors can be explained by considering the implications of the alternative, where the amount of balancing reserve is smaller because it is based on the hour-ahead errors in forecast wind. As stated above, all deviations between forecast and actual wind production need to be

[47] RNP/100, Lindsay/14.

covered. Thus, in scheduling the system day-ahead, which is performed for each day, the dispatchable generators would be scheduled to carry a *smaller* amount of response allowing them to cover deviations as determined from analysis of *hour-ahead* forecast errors. The dispatchable generators would not be scheduled to allow them to respond to day-ahead forecast errors, meaning that the response to these *larger* errors is only achieved by some other means, which in Idaho Power's view would too often translate to a risky reliance on the wholesale electric market. Consequently, the prudent simulation of day-ahead system scheduling is to ensure that dispatchable generators are capable of responding in real-time to uncertainty in wind production as determined by analysis of day-ahead forecast errors.

Q. Mr. Lindsay claims that Idaho Power's wind study is flawed due to the use of synthetic wind generation data.[48] How do you respond to this criticism?

A. In my judgment, Mr. Lindsay's criticism of the use of synthetic data is unfounded. Mr. Lindsay's believes that using synthetic data tends to overstate the correlation within the aggregate wind production time series, leading to an overestimation of balancing reserve requirements. In my view, the issue is really a question of geographic dispersion—for a given wind penetration level, a wind build-out having greater geographic dispersion is integrated at lower costs than a severely clustered build-out.

The geographic dispersion of the synthetic wind data used in Idaho Power's study is representative of the geographic dispersion of wind build-outs Idaho Power is likely to integrate. The wind data used for the study was provided by 3TIER, an industry leader in renewable energy risk analysis. Indeed, 3TIER developed the data set that was used by the National Renewable Energy Laboratory for its Western

[48] RNP/100, Lindsay/15.

Wind and Solar Integration Study ("WWSIS"), which when completed in 2010, was one of the largest and most comprehensive studies of wind and solar resources to date. The WWSIS included data for more than 32,000 existing or hypothetical wind project sites.

For Idaho Power's study, 3TIER developed a new time series directly from the WWSIS data set for 43 locations requested by Idaho Power. These locations correspond to project sites that either have a current contract or have requested a contract with Idaho Power. The 43 locations are spread across a wide region, with locations in five states—Oregon, Idaho, Utah, Wyoming, and Montana. The majority of the locations are in or peripheral to the Snake River plain in southern Idaho.

I believe the methodology used to develop the wind generation data used for the study ensures it accurately represents wind generation that is currently connected to and would likely be connected to Idaho Power's system in the future.

Q. Dr. Reading argues that QFs that are less than 10 MW should not have to pay an integration charge because they "should be dispersed geographically on the utility's system."[49] Do you agree with Dr. Reading's assumption regarding the geographic diversity of wind QFs on Idaho Power's system?

A. As noted above, Idaho Power's wind integration study took into account the geographic diversity of the Company's wind portfolio when determining the integration costs. The study's conclusions suggest clearly that even with geographically dispersed resources, there are integration charges for wind QFs of any size.

Q. Mr. Lindsay recommends that if the Commission does not adopt the wind integration cost adjustments in Idaho Power's study, that the Commission

[49] CREA/200, Reading/15.

direct Idaho Power to continue using its existing adjustment of $6.50 per megawatt-hour ("MWh").[50] Do you believe this would be appropriate?

A. I agree that it would be appropriate to assess a wind integration charge, but I do not agree that the Commission should adopt the Company's existing adjustment of $6.50 per MWh. This amount was the result of a negotiated settlement in Idaho. Both integration studies conducted by Idaho Power indicate the cost of wind integration is higher, and can be substantially higher if levels of wind penetration grow much beyond current levels. Based on the study results, the continued use of the existing price adjustment would expose Idaho Power's customers to increased integration costs, particularly if wind penetration expands. I believe the Commission should use the wind integration study results from the report filed as part of this docket as the basis for wind integration costs for QF projects.

Q. Dr. Reading relies on a 2007 U.S. Department of Energy ("USDOE") report on distributed generation to argue that a wind integration charge should not be assessed unless utilities compensate small QFs for the benefits they provide.[51] Do you agree with Dr. Reading's proposal?

A. No, I do not. A majority of the benefits identified in the USDOE report on distributed generation are provided by generation resources that can be dispatched or are capable of operating at a high capacity factor. The resource types mentioned in the report include combined heat and power, reciprocating engines, microturbines, and fuel cells. Some of the benefits of distributed generation identified in the report include:

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[50] RNP/100, Lindsay/15.

[51] CREA/100, Reading/15. The study is found at the following website: http://www.ferc.gov/legal/fed-sta/exp-study.pdf.

- Increased system reliability
- Improved power quality
- The provision of ancillary services
- Reduction of peak power requirements
- An emergency supply of power
- Diminished land use effects

Wind generation does not provide any of these benefits. In fact, the cost of wind integration is based on the fact that other dispatchable resources are necessary to integrate wind resources because of the variable and intermittent nature of wind.

In addition, the study itself states that it applies "to energy systems that produce electricity . . . at or near the point of use . . . [which] are typically situated within or near homes, buildings or industrial plants . . . ."[52] This description does not match the QF wind development that Idaho Power has experienced and therefore the results of this study do not apply to Idaho Power.

Q. Mr. Carver proposes that standard contracts should account for integration costs only if the wind QF is in the contiguous area where utilities have major wind resources and have procedures for forecasting wind project output.[53] Would this proposal allow Idaho Power to assess an integration charge as part of the standard contract?

A. No. Idaho Power has no utility-owned major wind resource. Therefore, if the Commission were to adopt Mr. Carver's proposal, only PacifiCorp and PGE would be authorized to assess an integration charge (and only for wind QFs located within a very small geographic area).

Q. Notwithstanding the fact that Mr. Carver's proposal would not cover Idaho Power, do you have any other concerns with his approach?

[52] Page 1.6 of the USDOE study.

[53] ODOE/100, Carver/9.

A. Yes. Implicit in Mr. Carver's proposal is his acknowledgement that a wind QF imposes costs on customers that are not accounted for in the calculation of the avoided cost price using the Standard Method. Indeed, Mr. Carver agrees that a wind QF seeking a standard contract using the renewable avoided cost price should be assessed an integration charge during the sufficiency period. So Mr. Carver agrees that customers are not being held indifferent when a wind QF obtains a standard contract. If that is the case, then the most basic mandate of PURPA is violated. There is no principled distinction between a wind QF requesting a standard contract and a wind QF requesting a renewable standard contract that would support the imposition of an integration charge in one case (renewable) but not the other (standard). For these reasons, Mr. Carver's proposal should be rejected and all wind QFs should be assessed an integration charge commensurate with the actual costs imposed on Idaho Power's customers as a result of the wind QF transaction.

VI. CONTRACT TERM

Q. Can you briefly restate Idaho Power's position on the appropriate length of a standard contract?

A. Idaho Power proposes that the Commission continue to authorize contracts for up to 20 years. However, Idaho Power proposes that the currently authorized 15-year fixed price portion of the contract be reduced to 10 years. Additionally, Idaho Power proposes that the Commission not allow a levelized contract price over the term of the contract.

Q. Mr. Schoenbeck argues that QFs are "penalized" because they do not receive contracts for the entire economic life of the project.[54] Do you believe that QFs should receive a single contract for their entire economic life?

[54] Coalition/200, Schoenbeck/2.

A. No. However, I believe that Mr. Schoenbeck's argument is somewhat misleading because QFs who continue to seek contracts with a utility do, in fact, receive contracts for their entire economic life. Contrary to Mr. Schoenbeck's implication, as long as PURPA exists, a QF remains certified, the QF project continues to produce energy, and the QF project requests to contract with the utility, PURPA requires that Idaho Power purchase its output. Therefore, the issue here is not whether a QF will be able to sell to a utility; rather, the issue is how the price is determined over the life of the contract. Idaho Power maintains that the fixed-price portion of the contract should be shortened so that it is less likely that the avoided costs paid to the QF deviates from the Company's actual avoided costs, which meets the requirements of PURPA that avoided costs are just and reasonable to customers and in the public interest.

Q. Will fixing the contract price for a 10-year period harm the QF project?

A. Not necessarily. No one knows how the fixed contract price will compare with the utility's actual avoided costs or market prices in the outer years of the contract. With a fixed price, the QF project receives a free financial hedge against the actual value of the energy. This hedge shifts the variable energy price risk from the QF developer to Idaho Power's customers. Previous Commission rulings and other parties in this case suggest that it is acceptable for Idaho Power's customers to assume some amount of this risk. Idaho Power's proposal is intended to more equitably share this risk.

Idaho Power has proposed that the fixed price term of a 20-year standard contract change from 15 to 10 years. Revising the fixed price term to 10 years shares the potential financial risk or reward associated with the fixed price evenly between the QF project and customers.

VII. MECHANICAL AVAILABILITY GUARANTEE ("MAG")

Q. Parties argue that a MAG is unnecessary because QFs have every incentive to generate as much as possible.[55] Is a MAG needed in PPAs?

A. Yes. A MAG is not simply a provision to ensure a project is mechanically available to produce energy. A MAG is also used for scheduling and forecasting energy delivery. The Company agrees with Mr. Bless's testimony on this point:

> This guarantee helps the utility and benefits ratepayers because the utility needs to factor the expected power from QFs into its short range and long range planning and scheduling. If the QF does not produce the expected power, the utility may need to find replacement power at a higher price than it would have incurred with more advance notice.[56]

Q. Does Idaho Power agree with Staff's recommendation that the Commission adopt parameters for planned maintenance allowance?

A. No. Within the calculations of Idaho Power's proposed MAG, allowances are made for force majeure, forced outages, and planned maintenance, with no specific time allotment for planned maintenance. As stated in other parties' comments in this case, QF projects have a very strong incentive to produce as much as they can because they are paid based upon delivered energy. Idaho Power assumes a QF project will limit planned maintenance to as short of time as possible.

Q. With a MAG, can a QF project get relief from events that are out of its control?

A. Yes. As Idaho Power has proposed, the "calculated net energy amount" in the Company's Idaho standard agreement for an intermittent resource contains a provision that allows relief from the MAG performance requirement for incidents of force majeure, scheduled maintenance, and forced outages. Inclusion of these

[55] *See, e.g.*, CREA/100, Hildebrand/20.

[56] Staff/100, Bless/41.

exceptions in the monthly "calculated net energy amount," the MAG, as applied by Idaho Power, is a reasonable requirement for QFs.

Q. What is the appropriate timeframe for determining availability for purposes of a MAG?

A. It is necessary to calculate a QF's mechanical availability over a short, rather than long, timeframe. This is why Idaho Power proposed determining availability on a monthly basis, rather than annually. Like all utilities, Idaho Power forecasts and schedules power on a day-ahead and hour-ahead basis, and must rely on accurate information for short-term and long-term planning. If the MAG is calculated using a timeframe greater than a month, it compromises the Company's ability to reasonably perform these scheduling and planning tasks. While a MAG does not guarantee that the QF will deliver estimated energy to Idaho Power, at least it provides incentives or assurance that the QF's equipment is mechanically ready to generate if motive force is available.

Q. Should MAG non-compliance result in contract termination?

A. Possibly. Under Idaho Power's current Oregon standard agreement for intermittent resources, failure to meet the MAG is an event of default. If an event of default occurs, the utility may terminate the contract. Within this case, Idaho Power has proposed a MAG calculation and process that reduces the energy prices paid to the QF project in months when the project does not meet the MAG requirements, with an option to issue a contract default notice to the QF project if the QF project consistently fails the MAG requirements. This default notice, if left uncured by the project, could result in termination.

VIII. UPDATES TO AVOIDED COST PRICES

Q. Can you briefly restate Idaho Power's proposal for updating avoided cost prices?

A. Yes. Idaho Power proposes an annual update of avoided cost prices based on the release of the EIA gas price forecast. The Company agrees that there needs to be a consistent approach to avoided cost updates to provide price certainty to both developers and ratepayers. More frequent updates also mitigate concerns that the avoided cost price will deviate from the Company's actual avoided cost between updates.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE
Docket No. UM 1610

I hereby certify that on April 29, 2013, I served the REPLY TESTIMONY OF M. MARK STOKES ON BEHALF OF IDAHO POWER COMPANY upon all parties of record in this proceeding by electronic mail only as all parties have waived paper service.

Brittany Andrus
Public Utility Commission of Oregon
brittany.andrus@state.or.us

Adam Bless
Public Utility Commission of Oregon
adam.bless@state.or.us

Stephanie S. Andrus
Department of Justice
Business Activities Section
stephanie.andrus@state.or.us

Bill Eddie
One Energy Renewables
bill@oneenergyrenewables.com

RNP Dockets
Renewable Northwest Project
dockets@rnp.org

Megan Walseth Decker
Renewable Northwest Project
megan@rnp.org

Will K. Carey
Annala, Carey, Baker, et al., PC
wcarey@hoodriverattorneys.com

Renee M. France
Oregon Department of Justice
Natural Resources Section
renee.m.france@doj.state.or.us

Melinda J. Davison
Davison Van Cleve PC
mjd@dvclaw.com
mail@dvclaw.com

S. Bradley Van Cleve
Davison Van Cleve PC
bvc@dvclaw.com

Irion A. Sanger
Davison Van Cleve PC
ias@dvclaw.com

John Lowe
Renewable Energy Coalition
jravenesanmarcos@yahoo.com

Oregon Dockets
PacifiCorp, d/b/a Pacific Power
oregondockets@pacificorp.com

R. Bryce Dalley
Pacific Power
bryce.dalley@pacificorp.com

Mary Wiencke
Pacific Power
mary.wiencke@pacificorp.com

Jay Tinker
Portland General Electric Company
pge.opuc.filings@pgn.com

J. Richard George
Portland General Electric Company
richard.george@pgn.com

Thomas H. Nelson
nelson@thnelson.com

Diane Henkels
Cleantech Law Partners PC
dhenkels@cleantechlawpartners.com

John W. Stephens
Esler Stephens & Buckley
stephens@eslerstephens.com
mec@eslerstephens.com

Matt Krumenauer
Oregon Department of Energy
matt.krumenauer@state.or.us

Kacia Brockman
Oregon Department of Energy
kacia.brockman@state.or.us

Jeffery S. Lovinger
Lovinger Kaufmann LLP
lovinger@lklaw.com

Kenneth Kaufmann
Lovinger Kaufmann LLP
kaufmann@lklaw.com

OPUC Dockets
Citizens' Utility Board of Oregon
dockets@oregoncub.org

Mike McArthur
Association of Oregon Counties
mmcarthur@aocweb.org

G. Catriona McCracken
Citizens' Utility Board of Oregon
catriona@oregoncub.org

Robert Jenks
Citizens' Utility Board of Oregon
bob@oregoncub.org

Toni Roush
Roush Hydro Inc.
tmroush@wvi.com

Elaine Prause
Energy Trust of Oregon
elaine.prause@energytrust.org

John M. Volkman
Energy Trust of Oregon
john.volkman@energytrust.org

Loyd Fery
dlchain@wvi.com

Daren Anderson
Northwest Energy Systems Company LLC
da@thenescogroup.com

Donald W. Schoenbeck
Regulatory & Cogeneration Services, Inc.
dws@r-c-s-inc.com

David A. Lokting
Stoll Berne
dlokting@stollberne.com

David Tooze
City of Portland, Planning and Sustainability
david.tooze@portlandoregon.gov

Glenn Montgomery
Oregon Solar Energy Industries Association
glenn@oseia.org

James Birkelund
Small Business Utility Advocates
james@utilityadvocates.org

Mark Pete Pengilly
Oregonians for Renewable Energy Policy
mpengilly@gmail.com

Kathleen Newman
Oregonians for Renewable Energy Policy
kathleenoipl@frontier.com
k.a.newman@frontier.com

Peter J. Richardson
Richardson & O'Leary, PLLC
peter@richardsonandoleary.com

Gregory M. Adams
Richardson & O'Leary, PLLC
greg@richardsonandoleary.com

Lisa F. Rackner
McDowell, Rackner & Gibson PC
dockets@mcd-law.com

J. Laurence Cable
Cable Huston Benedict Haagensen & Lloyd LLP
lcable@cablehuston.com

Chad M. Stokes
Cable Huston Benedict Haagensen & Lloyd LLP
cstokes@cablehuston.com

Paul D. Ackerman
Exelon Business Services Company, LLC
paul.ackerman@constellation.com

Adam Lowney
McDowell, Rackner & Gibson PC
adam@mcd-law.com

Richard Lorenz
Cable Huston Benedict Haagensen & Lloyd LLP
rlorenz@cablehuston.com

John Harvey
Exelon Wind LLC
john.harvey@exeloncorp.com

Christa Bearry

Christa Bearry, Legal Assistant