KRISTINE A. SASSER
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0357
BAR NO. 6618

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5918

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A DETERMINATION REGARDING ITS FIRM ENERGY SALES AGREEMENT WITH HIGH MESA ENERGY, LLC.	)	**CASE NO. IPC-E-11-26** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Kristine A. Sasser, Deputy Attorney General, and in response to the Notice of Application and Notice of Modified Procedure issued in Order No. 32414 on December 16, 2011, in Case No. IPC-E-11-26, submits the following comments.

BACKGROUND

On November 22, 2011, Idaho Power Company (Idaho Power; Company) filed an Application with the Commission requesting acceptance or rejection of a 20-year Firm Energy Sales Agreement (Agreement) between Idaho Power and High Mesa Energy, LLC (High Mesa) dated November 16, 2011. The Application states that High Mesa would sell and Idaho Power would purchase electric energy generated by the High Mesa wind project (Facility) located near Bliss, Idaho. The Application states that High Mesa proposes to own, operate and maintain a 40 MW (maximum capacity, nameplate) generating facility. Application at 2. The Facility will be a Qualifying Facility (QF) under the applicable provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Agreement is for a term of 20 years and contains avoided cost rates calculated through the use of the Integrated Resource Plan (IRP) avoided cost methodology as currently required by the Commission for wind QFs with a design capacity of more than 100 kilowatts (kW). Order No. 32262. High Mesa selected November 1, 2012, as its Scheduled First Energy Date and December 28, 2012, as its Scheduled Operation Date. *Id.* at 2.

The Application maintains that all applicable interconnection charges and monthly operation or maintenance charges under Schedule 72 will be assessed to High Mesa. Idaho Power states that the Facility is currently in the generator interconnection process. "Upon resolution of any and all upgrades required to acquire transmission capacity for this Facility's generation, and upon execution of the FESA and the GIA, this Facility may then be designated as a network resource." *Id.* at 5. High Mesa and Idaho Power have agreed to liquidated damage and security provisions. Agreement ¶¶ 5.3, 5.8.1.

Idaho Power states that the Facility has also been made aware of and accepted the provisions in the Agreement and Idaho Power's approved Schedule 72 regarding non-compensated curtailment or disconnection of its Facility should certain operating conditions develop on Idaho Power's system. The Application notes that the parties' intent and understanding is that "non-compensated curtailment would be exercised when the generation being provided by the Facility in certain operating conditions exceeds or approaches the minimum load levels of [Idaho Power's] system such that it may have a detrimental effect upon [Idaho Power's] ability to manage its thermal, hydro, and other resources in order to meet its obligation to reliably serve loads on its system." Application at 6.

STAFF ANALYSIS

Order Nos. 25882, 25883 and 25884, issued on January 31, 1995, require that utilities utilize their Integrated Resource Plans (IRPs) to establish avoided cost rates for larger PURPA projects. A general description of how the IRP methodology was intended to be employed was prepared by Commission Staff and was included as an exhibit to a Settlement Stipulation that was ultimately adopted by the Commission in Case No. IPC-E-95-9. Staff's description of the methodology, although fairly detailed, still falls far short of specifying all of the details that would be needed to apply the methodology to a specific project. It was intended that the details of the IRP methodology would be worked out over time as large projects were proposed, just as the SAR methodology evolved over the course of many years. However, almost no IRP-based projects were ever proposed; consequently, details of the methodology have never been fully fleshed out.

Over the course of the 16 years since the IRP methodology was first conceived, the computer models typically used in the IRP methodology have changed considerably and become far more powerful. In fact, some of the models currently used for the IRP methodology did not even exist in 1995. The IRP methodology has only been employed three times since its inception—once by Avista to develop rates for Potlatch's PURPA facility (now Clearwater Paper), once by Idaho Power to develop rates for the Rockland wind project, and once by Idaho Power to develop rates for the Interconnect Solar project.

There are numerous assumptions and decisions that must be made in order to use the IRP methodology, many of which are unique to particular generation technologies. Consequently, thorough review of this Agreement entails far more than just going through a checklist to ensure the methodology has been properly followed and the utility's avoided costs have been properly calculated.

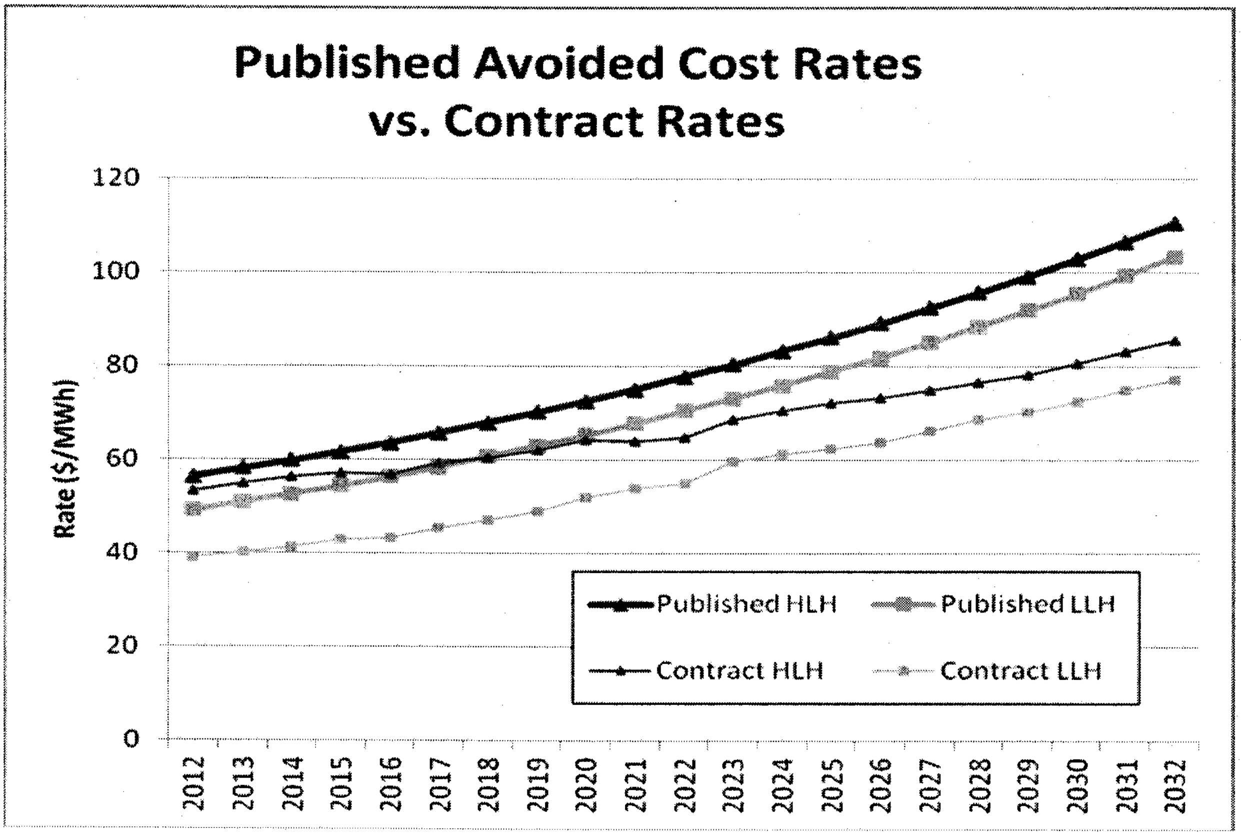
The Agreement presented for Commission approval contains rates, terms and conditions that differ considerably from those in recent power sales agreements wherein rates were based on published avoided cost rates. In this Agreement, an assortment of methods has been used to determine the rates. In particular, energy rates have been computed using an IRP methodology, and a capacity component to the rates has been computed using a new methodology not yet thoroughly scrutinized. In addition, some terms and conditions in the Agreement have been determined purely through negotiation between the parties.

Rates

The Agreement contains non-levelized avoided cost rates that escalate annually from 2012 through the end of the contract term in 2032. The rates are specified by month for both heavy and light load hours. Idaho Power notes that the energy price identified by the IRP methodology for this Facility is equivalent to a 20-year levelized price of $56.43 per MWh.[1]

[1] The actual energy pricing stream varies throughout the term of the contract based upon the time of year and time of day during which the energy is delivered to Idaho Power.

Application at 4. By comparison, the 20-year levelized published avoided cost rate is $68.51. A graphical comparison of the rates contained in the Agreement to currently approved published avoided cost rates, both for heavy and light load hours, is shown below.



Idaho Power's analysis indicates that a total of approximately $105 million will be paid to High Mesa over the 20-year term of the Agreement. The net present value of the payments is estimated to be approximately $45 million.

Although the rates in the Agreement were computed using the IRP methodology, as discussed above, there are many assumptions and computational details that have yet to be standardized. Most of these details are expected to be ironed out in the ongoing GNR-E-11-03 case. In the current case, Idaho Power has made assumptions and employed computational methods it believes are reasonable and within the bounds of the IRP methodology. However, Staff in some cases would have made different assumptions and calculations. Staff recommended that different assumptions and computational methods be used in the recent Interconnect Solar case (IPC-E-11-10). Although the Commission ultimately approved the contract stating that "Idaho Power negotiated an Agreement with Interconnect Solar based on its past practices and current understanding of this Commission's directives," the Commission recognized Staff's consideration of alternative factors. The Commission found that Staff's analysis considered "reasonable factors that the utilities should be considering while negotiating future power purchase agreements until such time as the Commission establishes firm guidelines for IRP-based rates." Order No. 32384 at 10.

With regard to computation methods and assumptions in this case, Idaho Power has adopted some of Staff's recommendations made in the Interconnect Solar case, but has rejected others. Staff continues to believe that certain other assumptions and computational methods are appropriate, and discusses its recommendations below.

CCCT vs. SCCT as Basis for Computing Capacity Value

As a basis for determining the capacity value of generation from the High Mesa Facility, Idaho Power used the capacity cost of a combined cycle combustion turbine (CCCT). In short, the Company considered the probability of the wind Facility to provide generation during the 3:00 pm to 7:00 pm peak load period during July, and in turn, valued this capacity based on the capacity costs of a CCCT from the Company's 2009 IRP.

In response to Staff production requests in the Interconnect Solar case, Idaho Power stated that it based the value of capacity on a CCCT in order to maintain consistency with the published avoided cost methodology and also to be consistent with previous IRP-based PURPA price calculations. The Company conceded, however, that as a solar project, the generation shape is distinctly different than other PURPA resources and it may be that a different resource such as a Simple Cycle Combustion Turbine (SCCT) more closely resembles the operating characteristics of a solar resource and thus may be a more appropriate basis for the avoided cost of capacity.

In the case of the High Mesa Wind Project, an annual capacity factor of about 26 percent is expected, and during Idaho Power's peak hours 3:00 pm to 7:00 pm in July, a peak hour capacity factor of only 5 percent is expected. Idaho Power's existing and future SCCT units would typically be dispatched in peak summer and winter hours, and would typically represent the lowest cost capacity Idaho Power could acquire. Wind generation could at various times displace generation from a SCCT unit or a CCCT unit.

To investigate whether an SCCT or a CCCT would be a more appropriate basis for calculating capacity value, Staff compared the capacity factors for SCCT and CCCT units included in the Company's 20-year resource plan in its 2009 IRP. Based on modeling results from the IRP, the capacity factors for Idaho Power's existing SCCT units and the future SCCT units in the preferred resource portfolio ranged from 0 to 14 percent, and averaged about nine percent for all peaking units. By contrast, the Langley Gulch CCCT, the only CCCT in Idaho Power's portfolio, shows an annual capacity factor ranging from 36 to 49 percent, with a 20-year average of 49 percent.

The annual capacity factor for the High Mesa Facility is estimated to be 26 percent, far less than the capacity factor for a typical CCCT but up to double the capacity factor for a typical SCCT. If an SCCT instead of a CCCT were used as the basis for calculating capacity value for the Facility, the calculated levelized price would drop from \$56.43 to \$53.47 per MWh.

It could be argued that the High Mesa facility has no capacity value because it cannot be guaranteed to provide capacity whenever needed with 100 percent certainty due to the intermittency of wind. Moreover, unlike a CCCT or a SCCT, a wind facility is not dispatchable. Because capacity provided by a wind facility cannot be guaranteed while capacity from either a CCCT or an SCCT can be provided with nearly 100 percent certainty, whatever capacity a wind facility can provide is not equivalent to the same unit of capacity from a dispatchable CCCT or SCCT.

Nonetheless, there is a high likelihood that the wind project can provide at least some capacity during Idaho Power's peak load hours. In recognition of this, Idaho Power examined generation estimates for the Project during the period from 3:00 pm to 7:00 pm in July when the utility's annual hourly peak load typically occurs. Idaho Power then chose a capacity value that would be exceeded 90 percent of the time. Idaho Power reasoned that the 90 percent exceedance value was appropriate because it was consistent with assumptions made for other resources in its IRP. While a 90 percent capacity factor may be reasonable for <u>planning purposes</u>, it could be argued that a 100 percent exceedance value should be used for a <u>rate determination</u> in order for the capacity of a wind facility to be equivalent to a unit of capacity from a SCCT or a CCCT. If a 100 percent exceedance criterion were used instead of a 90 percent value, the capacity value of the wind facility would necessarily decrease from the value computed by Idaho Power.

Amount of Capacity Value Captured in AURORA Energy Prices

To calculate the value of the energy component of the prices in the Agreement, Idaho Power modeled expected generation from the Facility using the AURORA electric price forecasting model. The Company assumed that the prices generated by the model reflected the costs of energy only, and that no capacity value was reflected in the prices.

The debate over whether AURORA prices include only energy value or whether there is at least some capacity value included is ongoing. Idaho Power's approach assumes that there is no capacity value reflected in AURORA prices. This assumption reasons that AURORA, when not run in a capacity expansion mode, is strictly a dispatch model that considers only the variable cost of operating resources. The opposing argument is that the marginal energy prices generated by AURORA permit resources to recover at least some fixed costs whenever they are not operating on the margin.

Staff believes that Idaho Power's assumption that AURORA prices reflect only the value of energy is a conservative one in favor of High Mesa. Staff believes that there is, in fact, some capacity value contained in AURORA prices. Although Staff is uncertain of how to quantify the amount, it is important to recognize that an alternative position to the assumptions made by Idaho Power exists.

Failure to Recognize Need for New Capacity

The method used by Idaho Power to calculate the capacity component of the prices in the Agreement fails to recognize whether and when Idaho Power actually has a need for new capacity. Under Idaho Power's approach, capacity value is added to the prices from the beginning of the Agreement's term through its entire duration. The fact is, however, that Idaho Power does not show a capacity deficit in its 2011 IRP until the year 2015. (The 2009 IRP showed a very small capacity deficit beginning in 2013). By adopting a pricing schedule that includes payment of a capacity component several years prior to Idaho Power's identified need for new capacity, prices in the Agreement are higher than they would be otherwise. Staff believes that some method needs to be devised and deployed to recognize need for new capacity (or lack of it in this case) in the computation of contract prices. In the case of wind projects, however, because they provide minimal capacity anyway, the failure to recognize need for new capacity in rate computations has a relatively minor effect.

Use of 2009 IRP Assumptions vs. 2011 IRP Assumptions

The analysis done by Idaho Power to derive the prices contained in the Agreement was based on data and assumptions from the Company's 2009 IRP. Key assumptions from the IRP that could significantly affect prices in the Agreement include fuel prices, resource costs, loads, makeup of the preferred portfolio, and CO2 prices and policy. Idaho Power used its 2009 IRP because it was the most recent IRP acknowledged by the Commission on August 17, 2011, the date on which the Company completed its price analysis. However, on December 30, 2011, the Commission issued an Order accepting Idaho Power's 2011 IRP. Reference Order No. 32425.

Although Idaho Power's use of the 2009 IRP for computing avoided cost rates was appropriate because it was the most recently acknowledged IRP at the time the analysis was done, the data and assumptions in the 2011 IRP are undeniably more current. Neither Idaho Power nor Staff has performed analysis to compute contract prices based on 2011 IRP data. Clearly, however, use of the 2011 IRP would produce different results. If this Agreement is rejected and must eventually be renegotiated, Staff recommends that the 2011 IRP be used as a basis for the analysis.

Weighted Cost of Capital Used in Idaho Power Analysis

In its analysis to compute the rates included in the Agreement, Idaho Power used a weighted cost of capital of seven percent. This is the same weighted cost of capital that the Company used in preparing its 2009 IRP. Staff believes that a more appropriate weighted cost of capital is 7.86 percent, the weighted cost of capital from Idaho Power's last general rate case (IPC-E-11-08). If a weighted cost of capital of 7.86 percent is used instead of seven percent, the avoided cost rates computed by Idaho Power would be lowered slightly.

Escalation of Prices from 2030-2032

For the last two years of the Agreement, Idaho Power estimated the avoided cost rates rather than computing them. Idaho Power's AURORA simulations from the 2009 IRP only extended through 2029, consequently, rates beyond 2029 could not be based exactly on AURORA. To derive rates beyond 2029, Idaho Power simply extrapolated the rates from the prior year using a three percent escalation rate. In this particular case, the effect of the extrapolation is very small; consequently, Staff does not object to it. However, Staff believes that a more appropriate approach would be to extend the years over which the AURORA modeling is conducted in order to capture energy prices over the full term of the Agreement.

Overall Impact of All Staff-Proposed Adjustments on Contract Rates

The overall impact of all of the changes proposed by Staff would be a decrease in avoided cost rates of approximately $3 per MWh. This is equivalent to slightly more than a five percent decrease.

The Agreement provides that High Mesa will own the Renewable Energy Credits (RECs) for the first 10 years of the Agreement and that Idaho Power will own them for the last 10 years. Agreement at ¶¶ 8.1, 8.2. REC ownership has been split in a similar fashion in several recent PURPA contracts. Staff has no objection to the sharing arrangement in the Agreement.

Related Cases

On September 1, 2011, the Commission initiated Case No. GNR-E-11-03. The purpose of the case is to review the terms of PURPA power purchase agreements including, but not limited to, the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) methodologies for calculating avoided cost rates. The case is the third phase of a more comprehensive review of PURPA-related issues. In the first phase, Case No. GNR-E-10-04, the primary issue was whether to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW while the Commission investigates other issues. In the second phase, Case No. GNR-E-11-01, the primary purpose was to address the issue of disaggregation of large wind and solar projects into small projects in order to obtain published avoided cost rates.

Staff expects that nearly all of the specific issues that have been raised regarding the High Mesa Agreement will be addressed more fully in a generic context in Case No. GNR-E-11-03. Because most of these issues will likely be common to other future contracts, Staff expects a full debate amongst all interested parties in the generic case. Staff intends that any positions it takes regarding the High Mesa Agreement be confined to only that Agreement, and not prejudice or set a precedent for any positions Staff may take in the generic case.

RECOMMENDATIONS

Pursuant to PURPA and FERC regulations, avoided costs paid to QFs are not to exceed the incremental cost that the utility would incur if it generated the energy/capacity itself or purchased from another source. Simply put, Staff does not believe that the rates contained in this Agreement are an accurate reflection of Idaho Power's avoided costs. Consequently, Staff recommends that the Commission not approve the Agreement. First, Staff believes that the capacity component of the rates should have been computed based on the cost of an SCCT instead of a CCCT, which would reduce the rates in the Agreement by about $3 per MWh. In addition, Staff believes that the rates in the Agreement fail to recognize Idaho Power's need (or lack of need) for new generation, particularly wind. Finally, Staff takes issue with use of 2009 rather than 2011 IRP assumptions and use of a seven percent discount rate.

Notwithstanding Staff's recommendation to not approve the Agreement, Staff acknowledges the Commission's support, and recent reinforcement of, rates derived by the IRP methodology and negotiations between the parties. (*See* Interconnect Solar, IPC-E-11-10, Order No. 32384). Staff recognizes that the assumptions and analysis techniques employed by Idaho Power in developing the rates in the Agreement may reflect past practice and the Company's current understanding of the IRP methodology. Furthermore, Staff recognizes that there is considerable room for negotiation, and that such flexibility has been exercised in this case.

Respectfully submitted this 26TH day of January 2012.

Kristine A. Sasser
Kristine A. Sasser
Deputy Attorney General

Technical Staff: Rick Sterling

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 26TH DAY OF JANUARY 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-11-26, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

DONOVAN E WALKER
JASON B. WILLIAMS
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: dwalker@idahopower.com
jwilliams@idahopower.com

RANDY C ALLPHIN
ENERGY CONTRACT ADMIN
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: rallphin@idahopower.com

HIGH MESA ENERGY LLC
C/O EXELON WIND
4601 WESTOWN PKWY
STE 300
WEST DES MOINES IA 50266
E-MAIL: urps@exeloncorp.com

HIGH MESA ENERGY LLC
RICHARD A CUMMINGS
COUNSEL FOR SELLER
PO BOX 1545
BOISE ID 83701
E-MAIL:
rcummings@cummingslawidaho.com

CHRISTI RITCHIE
E-MAIL ONLY: cjritchie@northrim.net

SECRETARY