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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 DYNAMIS ENERGY, LLC	**CASE NO. IPC-E-11-25** **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. 32413 on December 15, 2011, in Case No. IPC-E-11-25, 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 Dynamis Energy, LLC (Dynamis Energy; Dynamis) dated November 16, 2011. The Application states that Dynamis Energy would sell and Idaho Power would purchase electric energy generated by the Dynamis Ada County Landfill project (Facility; Project) located near Boise, Idaho. The Application states that Dynamis proposes to own, operate and maintain a 22 MW (maximum capacity, nameplate) landfill waste-to-energy generating facility. Application at 2. The Facility will be a 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) methodology. Dynamis Energy selected October 15, 2013, as its Scheduled First Energy Date and February 14, 2014, as its Scheduled Operation Date. *Id.* at 3.

The Application maintains that all applicable interconnection charges and monthly operation or maintenance charges under Schedule 72 will be assessed to Dynamis Energy. 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.

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 four times since its inception—once by Avista to develop rates for Potlatch's PURPA facility (now Clearwater Paper), and by Idaho Power to develop rates for the Rockland wind project, the Interconnect Solar project, and the High Mesa Wind 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 2014 through the end of the contract term in 2034. 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 $92.35 per MWh.[1] Application at 5. By comparison, the 20-year levelized published avoided cost rate is $73.44.

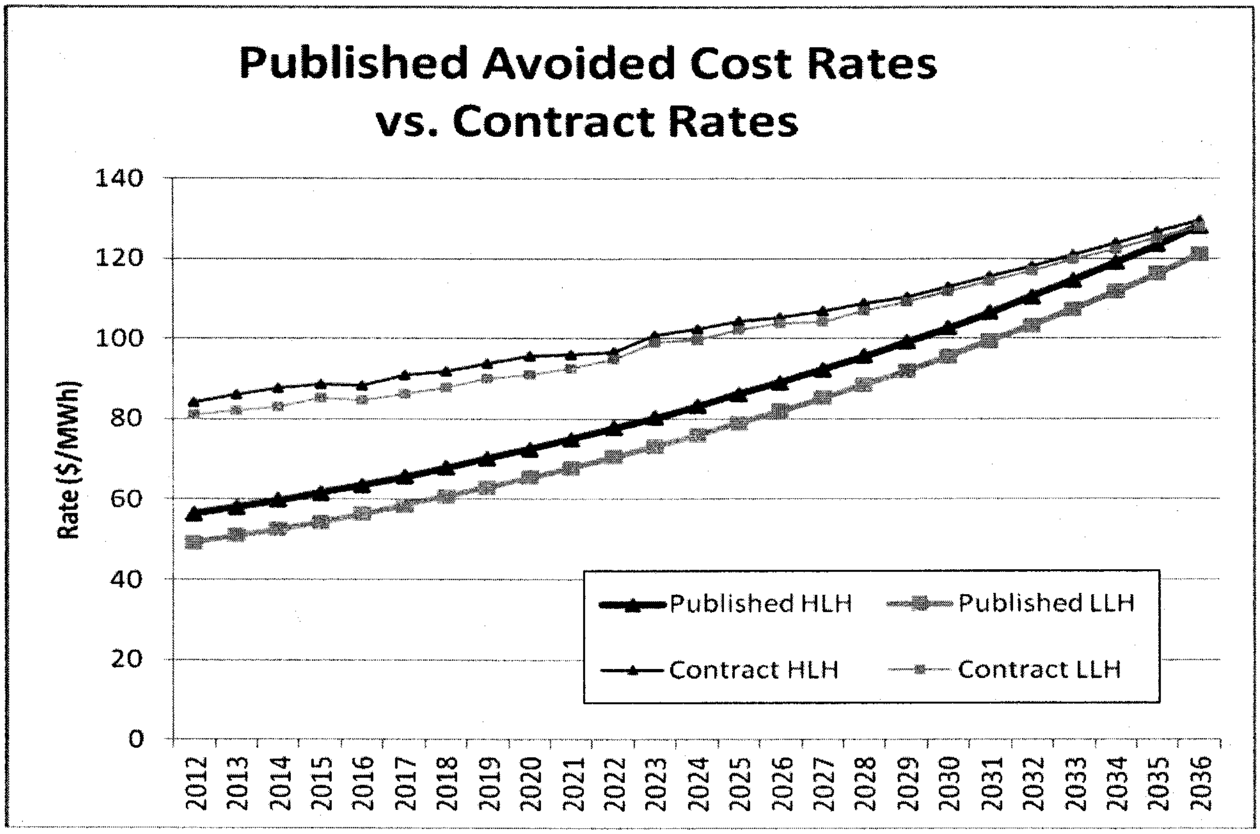
The rates in the Agreement appear high in comparison to both published rates and to rates contained in recent other PURPA contracts with IRP-based rates. (*See* High Mesa Wind, Case No. IPC-E-11-26, wherein the equivalent 20-year levelized rates is $56.43 per MWh). The higher rates in the Dynamis Agreement can be attributed primarily to the two following factors:

1) The Facility only plans to deliver energy between the hours of 8:00 am through 10:00 pm, every day of the year. Except for Sundays and holidays, all of these hours are heavy load hours when energy is substantially more valuable. No energy is proposed to be delivered at night, from 10:00 pm through 8:00 am.
2) Because the Facility is expected to operate daily at a very high daytime capacity factor, and because its generation will not be intermittent, 100 percent of the Facility's

[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.

capacity will be available during Idaho Power's peak load hours in the summer. Consequently, Dynamis Energy receives credit in rate calculations for its full nameplate capacity equal to the assumed capacity cost of a combined cycle combustion turbine (CCCT). By comparison, intermittent generation, like wind, receives credit for only a very small portion of its nameplate capacity, typically five percent.

For reference purposes, 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 $189 million will be paid to Dynamis Energy over the 20-year term of the Agreement. The net present value of the payments is estimated to be approximately $82 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.

Idaho Power Error in Computations

In reviewing responses to Staff's production requests in this case, Staff identified what it believes is an error in Idaho Power's computations to determine the capacity component of the rates. Idaho Power uses the capacity cost of a CCCT as the basis for computing capacity value of the QF. The underlying assumption in calculating capacity value is that, but for the addition of the new PUPRA QF, a CCCT would otherwise be built to provide capacity. The CCCT is assumed to be added in the same year that the PURPA QF goes online. Therefore, it is important that the CCCT capital cost reflect the construction cost in the same year as the Scheduled Operation Date as the QF.

In its analysis in this case, Idaho Power based its calculation of capacity value on the capital cost of a CCCT constructed in 2012, not in 2014 when Dynamis Energy's Scheduled Operation Date occurs. To correct this error, Staff believes that the assumed capital cost of the CCCT in 2012 should be inflated by two years to 2014. The effect of this correction, Staff believes, would be an increase in avoided cost rates of approximately $1 per MWh in each year of the Agreement.

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 Dynamis Energy. 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 one year 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 the Dynamis Project, the effect of failing to recognize the need for new capacity is relatively minor because the Project's Scheduled Operation Date is only one year before Idaho Power's identified capacity deficit.

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 July 8, 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.

Extrapolation of Prices from 2030-2034

For the last five 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, therefore, 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.

Renewable Energy Credits

The Agreement provides that Dynamis Energy and Idaho Power will split ownership of Renewable Energy Credits (RECs) on a 50/50 basis for the entire term of the Agreement. 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 Dynamis Energy 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 Dynamis Energy Agreement be confined to only that Agreement, and not prejudice or set a precedent for any positions Staff may take in the generic case.

Idaho Power and Customer Safeguards

Several public comments have been submitted expressing general concerns about risk exposure to ratepayers and taxpayers if the Dynamis Energy Project fails to perform. Dynamis Energy proposes to use gasification technology, which first involves thermally converting waste products into a combustible gas. The technology Dynamis Energy proposes to employ is new and relatively untested, at least in applications for commercial power production, and is much different than the technology used at two existing facilities located at the Ada County landfill.[2]

Idaho Power is required under PURPA to offer to purchase the Project's output, regardless of the technology employed, as long as the Project meets the requirements of a Qualifying Facility. Reference 18 C.F.R. §292.303(a). Similarly, the Commission does not have the authority to assess the viability of a project's technology as long as it has been certified as a QF by the Federal Energy Regulatory Commission. Idaho Power and the Commission can, however, require that the power sales agreement contain provisions to protect ratepayers if the project fails to perform. This Agreement contains numerous provisions intended to protect Idaho Power and its ratepayers. Most of the provisions have become standard in all PURPA contracts. Some of these provisions are described below.

No Payment for Energy not Delivered

Undoubtedly, the most significant safeguard for Idaho Power and its ratepayers is that no payment to Dynamis Energy is required unless energy is delivered. Although not an explicit term of the Agreement, this is the fundamental basis of all PUPRA contracts.

Delay Liquidated Damages

The Agreement requires that Delay Liquidated Damages will apply should Dynamis fail to bring the Facility on-line by the Scheduled Operation Date. If the Operation Date occurs after the Scheduled Operation Date, but within 90 days of that Scheduled Operation Date, then damages are equal to the sum of all Hourly Energy Production amounts for the entire Delay Period multiplied by the current month's market energy cost, but no less than $15 per MWh. The $15 per MWh minimum is a new requirement specific to this Agreement. (*See* Agreement at ¶ 1.6). If the Operation Date occurs more than 90 days past the Scheduled Operation Date, then damages are specified as $45 per kW of nameplate capacity for the Facility. If the Facility fails to achieve its Operation Date within 90 days of the Scheduled Operation Date, the failure will be a Material Breach of the Agreement and Idaho Power may terminate the Agreement if not cured by Dynamis. Reference Agreement at ¶¶ 5.3-5.6, ¶ 5.8.1.

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[2] One existing facility, online since 6/29/2006, has a 3.2 MW capacity and burns landfill gas collected from buried decomposing garbage. The other facility, not yet online, will be a twin to the original facility.

Delay Security

Dynamis and Idaho Power have also agreed to Delay Security provisions requiring Dynamis to post Delay Security in an amount equal to $45 per kW of nameplate capacity within 30 days of Commission approval of the Agreement. The purpose of Delay Security is to provide a source of funds in the event Delay Liquidated Damages are assessed. Reference Agreement at ¶ 5.8.1.

Reduced Price for Surplus Energy

Surplus Energy, generally, is energy produced by the Facility that is less than 90 percent or more than 110 percent of the hourly amounts specified in the Agreement. Surplus Energy is priced at the lower of the current month's market price or 85 percent of off-peak prices in the Agreement. The purpose of this contract provision is to encourage Dynamis to generate as closely as possible in accordance with the timing and amount specified in the Agreement. Reference Agreement at ¶¶ 1.38 and 7.4. The requirement for a reduced price for Surplus Energy is in accordance with Commission Order Nos. 29632 and 29682.

Minimum Generation Requirement

The Agreement contains minimum generation requirements that must be met by Dynamis. Reduced energy prices apply for short-term failures to meet minimum generation requirements. Failure to deliver 30,000 MWh in any year constitutes an event of Default. Reference Agreement at ¶¶ 6.3-6.4.

Security Requirements

The Agreement contains various standard security requirements in accordance with prior Commission orders. Reference Order Nos. 21690 and 29587. Security requirements include Engineer's Certifications for 1) Operations and Maintenance Policy, 2) Ongoing Operations and Maintenance, and 3) Design and Construction Adequacy. Reference Agreement at ¶¶ 4.1.4 and 19.3.2. The Agreement also includes minimum insurance requirements for Dynamis. Reference ¶ 4.1.5, ¶¶ 13.2-13.4, ¶ 19.3.1.

Non-Compensated Curtailment

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 6-7.

Other Terms of the Agreement

In addition to the various terms discussed above, the Agreement contains other standard terms and conditions intended to protect Idaho Power and its ratepayers. For example, the Agreement addresses Indemnification (¶ 13.1), Force Majeure (¶ 14.1), Liability (¶ 15.1), and Disputes and Default (¶ 19.1).

Minor Typographical Errors

There are several typographical errors in the Agreement that Staff believes need to be corrected. Appendix C of the Agreement includes Engineer's Certification forms for 1) Operation and Maintenance Policy, 2) Ongoing Operation and Maintenance, and 3) design and Construction Adequacy. Each of the three forms refers to a 15-year contract length. This should be corrected to refer to a 20-year contract length.

Staff Responsibility

Staff's responsibility in this case is to review the Firm Energy Sales Agreement between Idaho Power and Dynamis Energy and recommend that the Commission either approve or disapprove it. Staff must ensure that the rates in the Agreement fairly and accurately reflect Idaho Power's avoided costs, and that the terms and conditions contained in the Agreement are in compliance with PURPA. In exercising its responsibility, Staff must also ensure that Idaho Power and its ratepayers are reasonably protected from adverse impacts of project delay, deficient performance, default or termination.

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. 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 Idaho Power made an error in its computations of the capacity component of the rates, which would increase the rates in the Agreement by about $1 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. Finally, Staff takes issue with use of 2009 rather than 2011 IRP assumptions, use of a seven percent discount rate, and extrapolation of the rates for the final five years of the Agreement.

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 2ND day of February 2012.

Kristine A. Sasser

Kristine A. Sasser
Deputy Attorney General

Technical Staff: Rick Sterling

i:umisc:comments/ipce11.25ksrps comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 2ND DAY OF FEBRUARY 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-11-25, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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