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March 29, 2019

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: **Docket No. UM 2000**
In the Matter of Public Utility Commission of Oregon Investigation into PURPA Implementation

Filing Center:

Attached for filing is an electronic copy of Idaho Power Company's responses to Staff's questions in the above docket.

Sincerely,

Christa Bearry

Attachment

1221 W. Idaho St. (83702)
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UM 2000

IDAHO POWER COMPANY'S ANSWERS TO STAFF'S QUESTIONS

Set A - Current Utility Practices

1. Please provide a high-level description of modeling used to set avoided cost prices, including:

a. A description of variables included

b. Modeling methodology including software used

<u>ANSWER</u>

Schedule 85 sets forth both the standard rate tables, as well as the authorized process and requirements for requesting pricing and a contract. Idaho Power Company ("Idaho Power" or "Company") uses a different pricing methodology for proposed projects based upon the project's size.

Standard Prices:

For standard contract rates, which are applicable to solar Qualifying Facilities ("QF") with a nameplate capacity of 3 megawatts ("MW") or less and all non-solar QFs with a nameplate capacity of 10 MW or less, the modeling used to set avoided cost prices is a surrogate avoided resource model that assumes the utility avoided the cost of constructing a combined-cycle natural gas turbine. The modelling includes:

a. The following variables:

i. The first capacity deficient year identified in the Load and Resource Balance of the Company's most recently acknowledged Integrated Resource Plan ("IRP").

ii. Forward monthly market electricity prices to be used during the capacity sufficiency period.

iii. Cost inputs for the avoided proxy resource from the most recently acknowledged IRP, including:

1. Plant capacity;
2. Plant capital plus transmission capital costs;
3. Fixed operations and maintenance ("O&M") costs;
4. Variable O&M costs;
5. Other costs;

6. Heat rate;
7. Capacity factor;
8. Discount rate; and
9. Inflation rate.

iv. Natural gas price forecast.

v. Contribution to peak for the avoided proxy resource, as well as wind and solar resources.

vi. On-peak capacity (Availability) factors for the avoided proxy resource, as well as wind and solar resources.

vii. Current approved wind and solar integration charges.

b. Modeling is completed in Microsoft Excel. During capacity sufficient years, QFs are eligible for energy only payments based on forward monthly on- and off-peak market electricity prices adjusted for applicable integration charges. During capacity deficient years, QFs are eligible for energy payments which include both an energy and capacity component. During on-peak hours, avoided cost prices will account for the value of the QF resource type's on-peak capacity factor allocated to on-peak hours and the fuel and capitalized energy cost of the avoided proxy resource, adjusted for applicable integration charges. During off-peak hours, avoided cost prices will account for the fuel and capitalized energy cost of the avoided proxy resource, adjusted for applicable integration charges.

Non-Standard Avoided Cost Prices:

For non-standard contract rates, which are applicable to solar QFs with a nameplate capacity greater than 3 MW and all non-solar QFs with a nameplate capacity greater than 10 MW, the Incremental Cost Integrated Resource Plan ("ICIRP") modeling is used to set avoided cost prices as follows:

a. The following variables:

i. The first capacity deficient year identified in the Load and Resource Balance of the Company's most recently acknowledged IRP.

ii. Cost inputs for the avoided proxy resource, simple cycle combustion turbine ("SCCT") from the most recently acknowledged IRP, including:

1. Plant capacity;
2. Plant capital plus transmission capital costs;
3. Fixed O&M costs;

4. Variable O&M costs;
5. Other costs;
6. Heat rate;
7. Capacity factor;
8. Discount rate; and
9. Inflation rate;

iii. Natural gas price forecast.

iv. System load forecast.

v. Cogeneration and Small Power Production forecast.

vi. New, terminated, and expired contracts.

vii. Long-term contract commitments.

viii. Proposed QF contracts.

ix. Project nameplate rating (AC).

x. Hourly generation profile.

xi. Estimated on-line date.

xii. Contribution to peak.

xiii. On-peak capacity (Availability) factors.

xiv. Current approved wind and solar integration charges.

b. Software used to perform analysis, store, and report data includes: Microsoft Excel, SQL Server, SharePoint, and the AURORA model.

Avoided Cost of Capacity. The kilowatt ("kW")/month capital cost is based on a SCCT, included in the current IRP, allocated to a proposed project once Idaho Power becomes capacity deficient as determined by the current IRP. The project's avoided capacity value is based on the contribution to peak from the specific project being priced.

Avoided Cost of Energy. Modeling is initially completed using AURORA power supply modeling software, which utilizes inputs from the most recent acknowledged IRP and determines the generation resources being used to serve load and the incremental cost of these various generation resources. The avoided cost of energy is the weighted average of the highest hourly incremental cost displaceable resources that are being displaced by the proposed QF's hourly energy deliveries. The inputs to the methodology are updated annually to include the most recent natural gas and Idaho Power load forecasts. AURORA model runs are then uploaded to a SQL Server database allowing for pricing reports to be developed. During capacity sufficient years, QFs are eligible for energy only payments based on forward monthly on- and off-peak market electricity prices adjusted for applicable integration charges. During capacity deficient years, QFs are eligible for energy payments which include both an energy and capacity component.

The indicative pricing (Avoided Cost) provided to a proposed QF project is a monthly Heavy Load (HL) and Light Load (LL) price. To calculate these prices, a weighted average of the multiple values calculated above is created for HL and LL hours in each month. This calculation is then repeated for each month of the energy sales agreement ("ESA") term creating a unique monthly HL and LL Avoided Cost of Energy for each proposed QF project that is included in the indicative prices provided to the proposed QF project

2. Please explain the process that a QF goes through when requesting an energy sales agreement with a utility. For this process include the following information, and note any differences between applications for standard rates, standard contracts, or non-standard contracts.

a. List any software programs that aid in the application process

b. Provide a complete timeline, with breakdowns for each step of the process

c. Provide a complete list of informational requirements from the QF

d. Provide a list of data/information issues that could impede the contracting process

ANSWER

a. The process that a QF goes through when requesting an ESA is found in Idaho Power's Schedule 85 Cogeneration and Small Power Production Standard Contract Prices located at: https://www.idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/. The majority of information needed by the utility from a QF when requesting an ESA can be provided using Microsoft Excel, Word, and Adobe documents.

b. The timeline is specified in Schedule 85, paragraph 2, and generally includes that once a QF's application is deemed complete, Idaho Power will provide the QF with a draft ESA within 15 business days. Upon receiving a request for a final ESA, the Company must respond within 15 business days. The process for a non-standard ESA generally begins with the Company providing the proposed QF with an indicative pricing proposal within 30 days of receipt of the information required by the Company to prepare the indicative pricing proposal. After the QF has reviewed the indicative pricing proposal and requested a draft ESA from the utility, a draft ESA must be provided within 30 days.

c. Paragraph 2 of Schedule 85 describes the process for providing project information to Idaho Power. If a project is not eligible for a standard contract, then the project will submit a written request for a non-standard contract with detailed information to Idaho Power at the address listed under paragraph 2.a, Communications.

3. Please describe the interconnection process that a QF is currently required to follow. With this description please note any differences between QFs and any other projects requesting interconnection and explain the rationale behind any such differences.

a. List the point of contact in the utility.

b. Provide a timeline that an interconnection request follows. Please include all relevant steps form submission request to actual connection.

c. Provide a complete list of informational requirements from the QF.

d. Provide a list of data/information issues that could impede the interconnection process.

e. Provide a description if and/or how this process interacts with requesting an energy sales agreement.

ANSWER

The interconnection process that a QF is required to follow is found on Idaho Power's website under Generator Interconnections, and governed by the adopted Oregon Administrative Rules, and the Public Utility Commission of Oregon ("Commission" or "OPUC") order adopting a modified version of the OATT pro forma documents/process. The link on Idaho Power's website is: https://www.idahopower.com/about-us/doing-business-with-us/generator-interconnection/.

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b. The interconnection timeline is as follows:

1. Within 10 business days of receipt of an application to interconnect a small generator facility, the interconnecting public utility must provide written notice to the applicant stating whether the application is complete.

2. If the application is incomplete, the public utility must provide a detailed list to the applicant of what data is missing. The applicant must provide the delinquent data within 10 business days or the application is deemed withdrawn.

3. The public utility must schedule the Scoping Meeting within 10 business days of receiving a completed application.

4. The public utility issues the applicant a Feasibility Study Agreement ("FeSA") within five business days of the Scoping Meeting.

5. The applicant has 15 business days to execute the FeSA or the application is deemed withdrawn.

6. Once the FeSA is executed by both parties, the public utility has 30 business days to perform the Feasibility Study Report ("FeSR").

7. The public utility must provide a copy of the FeSR to the applicant within five business days of the study's completion.

8. If a System Impact Study ("SIS") is required, the public utility must issue the applicant a SIS Agreement ("SISA").

9. The applicant must execute the SISA within 15 business days of receipt of the agreement or the application is deemed withdrawn.

10. Once the SISA is executed by both parties, the public utility has 45 business days to perform the SIS.

11. The public utility must provide a copy of the System Impact Study Report (SISR) to the applicant within five business days of the study's completion.

12. If it is determined by the public utility that a Facility Study ("FS") is required, the public utility must provide the applicant with a FS agreement within five business days.

13. The public utility has 45 business days to perform the FS.

14. The public utility must provide a copy of the Facility Study Report (FSR) to the applicant within five business days of the study's completion.

15. Upon completion of the FS, and with the agreement of the applicant to pay for interconnection facilities and any applicable system upgrades identified in the FS, the public utility shall provide the applicant an executable Generator Interconnection Agreement (GIA) within five business days.

16. Depending on the size of the project, interconnection construction generally ranges from 3 to 18 months, at which point the project is interconnected and ready to generate onto the Idaho Power system.

c. Following are the informational requirements from the QF:

1. Feasibility Study phase

    i. Completed application with proposed point of interconnection latitude and longitude.

    ii. Single Line Diagram including transformer connection configuration and impedance.

    iii. Equipment technical information.

        1. Inverter based.

            a. Energy source (panels, etc.).
            b. Inverter.

                i. Certifications.
                ii. Listings.
                iii. Standards compliance.

            c. Plant controller.

        2. Rotating machines.

            a. Generator, including all impedances.
            b. Voltage regulator.
            c. Controller.
            d. Machine capability curve.

2. System Impact Study phase.

   i. Steady state inverter/generator models in Western Electricity Coordinating Council ("WECC") approved format.

      1. Inverter/machine data.
      2. Collector data.
      3. Transformer(s) data.

   ii. Dynamic models in WECC approved format.

      1. Machine.
      2. Exciter.
      3. Plant controller.

d. Failure by the applicant to provide the following in a timely manner can impede the interconnection process:

   1. Proposed point of interconnection not clearly stated and/or located.

   2. Single line diagram incorrect or missing data.

   3. Transformer connection configuration and grounding incorrect.

   4. Selected inverters not capable of meeting reactive power requirements.

   5. Selected inverters are not IEEE 1547-2018 or UL 1741 SA compliant.

   6. Supplied models not in WECC approved format.

   7. Equipment changes during the study process.

   8. Allowing time for "affected systems" to review the studies.

e. Describe below is how this process interacts with requesting an ESA.

   1. Once the construction and commissioning are complete, the interconnection manager issues a construction complete letter to the ESA department, notifying them that construction is complete and the applicant is allowed to generate onto the grid. Generally speaking, the applicant has correspondence with the purchaser of its project's output regarding the ESA while also working through the interconnection process. In Idaho Power's case, the different groups responsible for the interconnection and energy sales processes correspond regularly as well.

4. Please provide a list of any utility resources that could help inform QF developers as to locations that would benefit from, or face challenges to development.

ANSWER

Examination of the publicly available queue information from Idaho Power's OASIS website, request and examine previous study reports, and take part in the official pre-application process are all ways to gain additional information and analyze a particular area for interconnection.

5. How do utilities treat QFs with storage currently for PURPA purposes?

a. How is the capacity determined for such a project

b. Would a renewable generator collocated with storage be eligible for renewable avoided cost pricing? Please explain.

ANSWER

Idaho Power does not have any QFs with storage that have been proposed. In the Company's Idaho jurisdiction, several proposed battery storage facilities have attempted to obtain Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts based upon an assertion that they are self-certified QFs, independent of their source of generation. The Idaho Public Utilities Commission ("Idaho Commission") found that, assuming the validity of the proposed projects' self-certifications, that the projects would be eligible for rates and contracts in the same manner as their source of generation, which in the particular instance before the Idaho Commission was solar. Case No. IPC-E-17-01, Order No. 33785, Order No. 33858. One group of these proposed battery storage facilities petitioned the Federal Energy Regulatory Commission ("FERC") to initiate an enforcement action against the Idaho Commission regarding this determination. FERC declined to initiate an enforcement action and the proposed QFs filed their own enforcement action against the Idaho Commission in the Federal District Court of Idaho, which is currently pending. Case No. 1:18-cv-00236-REB.

6. When can existing QF projects renew their QF contracts? Can a renewal occur prior to the expiration of the current contract? If so, how long before expiration of the current contract can a QF enter into a new contract?

ANSWER

QF projects that are already on-line and currently selling energy to Idaho Power under a PURPA ESA can submit a request for a replacement ESA at any time. However, Idaho Power needs to receive a request for a replacement ESA approximately one year prior to the expiration of the current contract so that there is sufficient time to prepare a new contract before the current contract expires. The replacement ESA will need to have the most current and applicable rates that have been updated closest to the date of the current contract expiration. After the Schedule 85 Avoided Cost Price Tables found under paragraph 2 are updated (usually in May of each year), Idaho Power will include these updated prices to the replacement contract before executing the contract. Although the replacement contract would be executed before the expiration of the current contract, but after the avoided cost prices are updated, the start date for the replacement contract would start at the time the existing contract expires.

7. Please explain transmission requirements for new QFs. Please explain any differences for existing versus new QFs related to transmission requirements.

ANSWER

A new proposed PURA QF, that desires to sell its output to the utility that it interconnects with must first apply for interconnection to the utility. That QF must be a designated network resource to serve utility load ("NR" as opposed to an energy only resource "ER"). As part of Idaho Power's processes when a QF applies for interconnection as NR, the ensuing studies will identify potential system upgrades required for that project to interconnect to the utility's system and be designated as a network resource. A transmission service request must also be made by the utility's merchant of load serving operations on behalf of the QF's generation. If there is no available transmission capacity to accommodate the QF's generation to be designated as a network resource to serve load, then system impact and facility studies must be performed to identify any required network transmission related upgrades that may be required to accommodate the QF's generation. Depending upon the timing and sequencing of the QF's requests for interconnection as a network resource, and its request for a power sales agreement with the utility, it may be possible to study interconnection and transmission requirements simultaneously.

8. How are QF contracts treated in long-term planning processes? Are the assumptions consistent for IRP planning as those used in other internal planning processes? Are existing QF contracts assumed to renew or not renew at the end of a contract? Please explain.

ANSWER

Signed QF contracts are included in Idaho Power's long-term planning processes as must-run generators in the Company's resource stack. Idaho Power's cogeneration and small power production ("CSPP") forecast, which includes all QFs under contract, is developed for each project based on a number of factors, including contract estimated generation amounts, most recent 12-month history, five-year rolling average, project-adjusted estimated net energy amounts, and any previous or current adjustments. Generally, the starting point is the rolling five-year historical average of monthly generation (or shorter if the project has operated less than five years). If a project has operated less than one year, the generation estimates from the project's ESA are used.

The assumptions used in this forecast are consistent when applied to the IRP process and internal planning processes. The CSPP operational forecast assumes that all resource types will request replacement contracts upon the expiration of an existing ESA, except for wind projects. The majority of resource types have a track record of continued operations after the expiration of their original ESA, whereas wind resources do not have the same track record. It is not known if QF wind generators will invest resources into repowering their projects upon the expiration of their initial contracts.

Set B - General Questions

9. Should the current standard pricing methodology be retained? If not, what should the methodology be? Please describe in detail, and provide examples of where the proposed methodology may currently be in use. If not, in this description include the following:

a. How proposal meets customer indifference standard

b. How proposal meets need for transparency

c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process.

ANSWER

The current standard pricing methodology should be modified to eliminate its reliance upon a natural gas combustion turbine surrogate avoided resource. The assumption that the utility avoids the cost of constructing and operating a gas turbine by the acquisition of PUPRA generation is an incorrect assumption that results in over-inflated prices that are harmful to customers. Idaho Power's ICIRP avoided cost pricing methodology, that is currently used for avoided cost pricing for QF that exceed the standard rate eligibility cap, is a much better estimation of cost as to what the utility could potential "avoid"—or, in other words, the ICIRP methodology better aligns with the definition of avoided cost—the cost which, but for the purchase from the QF, the utility would pay to otherwise generate or purchase from another source. The ICIRP is based upon the estimated hourly generation profile of the proposed QF, and assigns on an hourly basis the highest cost, displaceable utility resource that is operating for the same hour that the QF delivers its generation as the avoided cost.

A better pricing methodology would base the utility's avoided cost upon a transparent firm and non-firm electric market price index, and a QF's eligibility for firm or non-firm pricing in its PURPA contract would be based upon the QF's ability to deliver on a firm, scheduled basis with the utility. Resources that the utility is able to acquire on a least cost, reliable operation basis should also inform the proper avoided cost determination. These methodology changes are required to eliminate the harm to customers that results from the currently inflated avoided cost pricing, that exceeds market prices, and, in many cases, the cost that the utility would pay to either purchase from the market or to acquire a similar non-PURPA resource.

10. Should separate price streams be offered for a nonrenewable and a renewable avoided resource? If yes, please explain why and provide a description of the proposed avoided cost pricing methodology. In this description include the following:

a. How proposal meets customer indifference standard

b. How proposal meets need for transparency

c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process

ANSWER

No. The renewable attributes of a project should be determined to be owned by the utility and its customers that are required to purchase the generation; separate price streams are not necessary.

11. Should documents and models used in the standard pricing and contracting practices be changed to be consistent for all utilities?

a. Should standard PPAs be modified such that the bulk of the document is the same for each utility? Please explain.

b. Should the spreadsheet models used to calculate standard prices be modified so that inputs and outputs are easily found and compared?

c. If standard contracts become homogenized across utilities with less flexibility, how could the OPUC be involved in non-standard contract development and negotiation?

ANSWER

Documents and models used in standard pricing and contracting practices are generally consistent for the three electric investor-owned utilities in Oregon as standard contracts contain many similar provisions and terms. The methodologies for determining standard avoided cost pricing are also generally consistent and many of the variables are applied similarly by each utility. However, it should be expected that each utility is configured differently, and each must have the ability to include utility specific pricing, cost data, provisions, and terms to integrate QF generation with the utility's system.

12. Please provide any ideas related to generally improving the efficiency of the regulatory process associated with updating avoided cost prices.

ANSWER

New avoided cost rates should become effective upon the utility's initial filing for the rate update, and made subject to true-up or revision in an ensuing docket where the filing is subject to the Commission's and other parties' review.

13. Please explain an optimal process for a QF requesting an energy sales agreement with a utility. For this process please note any differences between applications for standard rates, standard contracts, or non-standard contracts.

ANSWER

The optimal process for a QF to request an ESA with the utility is to follow the process outlined in each utility's schedule for cogeneration and small power production facilities. The schedule should include specific timeframes for contract discussion and negotiations, and for determining a proposed project's appropriate avoided cost pricing. The schedule should also specify the time that contract negotiations are completed by either the execution of an ESA or a determination that any previously provided drafts, pricing, etc., are no longer valid and the process for requesting an ESA must start anew.

14. Please describe an optimal interconnection process for a QF requesting interconnection.

ANSWER

The QF would request a series of redacted studies in a particular area to analyze the possibility of interconnection in that area. The QF would then utilize the pre-application process to further analyze viability of availability in that area. Once the pre-application data is analyzed, the regular interconnection processes would be followed.

15. How should storage be treated under PURPA implementation? Please discuss treatment for stand-alone storage, storage collocated with non-renewable generation, and storage collocated with renewable generation. Provide the applicable avoided cost pricing approaches for the listed possibilities.

ANSWER

Please see Idaho Power's response to Question No. 5 above. Additionally, the question of whether a stand-alone battery storage facility, or battery storage that is energized with non-renewable generation is a valid QF entitled to the same independent treatment as a QF generator, is a question that will likely need to be answered by the FERC.

With regard appropriately pricing a QF project, such as wind or solar, that also has battery storage capability, Idaho Power's existing ICIRP methodology (or similar) is ideally structured to properly estimate a price for such facility. Current battery technology operation is not able to indefinitely store and dispatch energy. It is able to store and shift energy deliveries from the generator. (For example, a currently examined utility scale battery storage facility has a maximum storage of up to 4 hours). The ICIRP methodology, being based upon the generation profile of the proposed project, can accurately price the hourly shifts in generation that would result from operating wind and solar in conjunction with battery storage facilities. The maximum instantaneous MW amount that the facility is capable of delivering at any moment in time, and for which the interconnection and related transmission is designed to accommodate would be the nameplate for such a combined facility.

16. How should existing projects be treated under PURPA implementation? Please address the following, in addition to any other relevant topics.

a. Renewals

b. Pricing (including capacity treatment)

ANSWER

Existing projects should be treated like any other newly proposed project, where the existing QF can request a new contract that may have a commercial operation date go into effect upon the expiration of the existing contract. If a QF obtains a replacement contract with no lapse between the expiration of the current contract and the implementation of the new contract, some of the items required by the terms and conditions of the new contract may be carried over from the expiring contract. As it relates to pricing and capacity value, the Idaho Commission has determined that a QF project, if being paid for capacity at the end of current contract term, is eligible for the immediate payment of capacity in the replacement contract. *See* Idaho Commission Order No. 32697, p. 21.

17. Should the existing dispute resolution process be continued? If not, how should it be changed?

ANSWER

See Idaho Power's response to Question 18.

18. Please share your recommendations to reduce the volume of litigation regarding complaints.

ANSWER

Complaints are a normal part of a dispute resolution process. The best way to handle a volume of complaints is to expeditiously move such complaints to a final resolution, and through a due process proceeding.

19. What existing resources (educational, etc.) do you know of that could benefit the Commission and other stakeholders during or prior to the investigation?

ANSWER

See Idaho Power's response to Question 20.

20. What is the best process for the Commission to educate, inform and engage itself and its stakeholders around the questions related to PURPA implementation?

ANSWER

The Commission is the only party that can properly answer such a question. Conducting proceedings, such as the present, is a good way to engage, educate, learn, and inform—as all are required to properly hear, deliberate, and decide a case or matter.

21. Given recent utility practice of acquiring resources on an economic basis, outside of need, should the Commission change the current practice of using IRP resource acquisition to define resource sufficiency/deficiency (thereby defining payments for capacity)?

a. If yes, how should the Commission determine eligibility and pricing for capacity payments?

ANSWER

No, the current practice of using IRP resource acquisition to define resource sufficiency/deficiency is appropriate—and more precisely, the IRP's determination of the utility's first capacity deficit is the appropriate measure. Resources acquired outside of the IRP process for economic reasons are only done due to the low price that is beneficial to customers to acquire and operate on the utility's system—in particular, in relation to the alternative cost of PURPA avoided cost purchases and market price. If utilities were required to make additional capacity payments to QFs, outside of the IRP's capacity sufficiency determination, without the corresponding low price that is beneficial to customers that is present for the non-PURPA acquisitions, then customers would be harmed by utilities needlessly acquiring generation from QF projects at higher avoided cost prices than other available resources.

22. When in the process of contracting should a legally enforceable obligation (LEO) be obtained?

ANSWER

In addition to the current requirements of the Commission regarding formation of a LEO, a QF should not be able to lock-in outdated and higher avoided cost rates pursuant to a

LEO for longer than one year. Avoided cost rates update at least on an annual basis, and one year provides more than sufficient time for a QF to move into development of its facility after the LEO is established—the legally enforceable obligation that the QF will build a project and deliver generation.

23. Currently, a QF can have a LEO or executed contract, fail to achieve commercial operation, and as a practical matter not be required to pay a penalty to the utility because the utility's costs to replace the QF's power do not exceed the costs the utility would have incurred under the contract. Would imposing a different type of penalty for non-performance once a LEO is obtained or a contract executed be appropriate? Please explain.

ANSWER

First of all, the answer to the problem posed in the question above is to get the avoided cost price right. The fact that it is the typical case that the utility's cost to replace the QF's power is almost always lower than the avoided cost prices locked-in in the contract conclusively demonstrates by itself that the avoided cost rates are wrong and passing along costs that are harmful to customers compared to what the utility could otherwise acquire or spend. Secondly, enforcement of a LEO upon a QF; i.e., assuring that it lives up to its obligation to construct and deliver energy, is not a penalty, but is based upon damages. Rather than a traditional differential between market and contract price, which by design almost never results in the establishment of damages because avoided costs are almost always higher than market, a liquidated damages calculation could be set in the contract that would be applicable and forfeit if the project is not built, or not built on time. For example, the posting of delay damage security in the amount of $45 per kW of nameplate, which would be forfeit as liquidated damages for facility to bring the facility on-line by the scheduled commercial operation date.

24. What is required for a QF project to receive financing?

ANSWER

The more appropriate phrasing of this question should be, does PURPA require the Commission to promote the development of QFs through providing terms and conditions that result in favorable financing to build projects? A purpose of PURPA is to promote the development of alternative generation facilities. This purpose is accomplished and realized by the mandatory purchase obligation that PURPA imposes upon regulated utilities. This purpose, promotion, is not supposed to be accomplished through the price and other terms of a purchase deal—those are required to be set, not a price that encourages development, but at the utility's avoided cost—and most importantly at a price that does not harm utility customers, but hold them indifferent. By passing on additional burdens of locking-in all of the price risk over long-term obligations, that are never able to be changed no matter how far they deviate from actuals, customers are no longer indifferent.

25. Assuming a two-phase process, what issue do you believe could be fast-tracked within Phase 1?

ANSWER

A two-phase process should not be assumed. The Commission should set a definitive procedural schedule to resolve all issues raised in the proceeding that is designed to conclude within one-year from the time it is initiated. The nature of the issues involved with PURPA do not lend themselves to a division into two phases. Additionally, the Commission, in its consideration of initial interim relief has in a way conducted an initial phase.

26. Assuming a two-phase process, what issues do you believe need additional time for analysis? (i.e. should be addressed in Phase 2).

ANSWER

See Idaho Power's response to Question 25.

27. Please share one to two specific suggestions you would make to change how the cost of network upgrades are assigned and socialized? Describe why your suggestion is reasonable in terms of how the cost would *[sic]* allocated?

ANSWER

Network upgrades required by the addition of a QF facility must remain the responsibility of the QF to pay. The question assumes socialization of such costs? This would be entirely improper, and a direct violation of the requirement that customers not be harmed, and remain neutral to the PURPA transactions.

28. Please provide any additional comments or concerns that you would like to see addressed in this investigation.

ANSWER

Idaho Power's concerns could be addressed within the context of the broad areas that are raised by the preceding 27 questions.