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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER APPROVING THE METHODOLOGY FOR AVOIDED COST RATE NEGOTIATIONS WITH QUALIFYING FACILITIES LARGER THAN 1 MEGAWATT.	**CASE NO. IPC-E-95-9**

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 14, 1996

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from July of 1983 to April of 1994. I received my Idaho license as a registered professional Civil Engineer in 1988. I began working at the Idaho Public Utilities Commission in April of 1994. I have since attended the annual regulatory studies program sponsored by the National Association of Regulatory Commissioners (NARUC) at Michigan State University, the 1995 Lawrence Berkeley Laboratory Advanced IRP Seminar, and an advanced IRP course sponsored by EPRI entitled "Resource Planning in a Competitive Environment." My duties at the Commission include analysis of utility rate applications, rate design, tariff analysis and customer petitions.

Q. Have you testified before the Commission previously on avoided cost matters?

A. Yes, I provided testimony in the combined avoided cost cases IPC-E-93-28, WWP-E-93-10, PPL-E-93-5/ UPL-E-93-7, and UPL-E-93-3/PPL-E-93-3.

Q. What is the purpose of your testimony in this case?

A. I will discuss the settlement reached in this case in which the parties were able to resolve a number of the issues related to the formulation of a generic avoided cost methodology for larger QF projects.

Q. Did you participate in formulating the settlement in this case?

A. Yes, I participated in all negotiation meetings in this case. I was also the primary author of Staff's Proposed Avoided Cost Methodology, which is referenced in the settlement stipulation in this case. The stipulation is included as Exhibit No. 101. Incidentally, I have been informed that Mssrs. Don Olowinski, John Runft and Peter Richardson will not sign the stipulation and intend to neither actively support nor oppose the settlement.

Q. Briefly describe the process followed in formulating the stipulation.

A. At the conclusion of the combined avoided cost case, Order Nos. 25882, 25883 and 25884 were issued by the Commission on January 31, 1995. The orders required that a least cost planning methodology be used to calculate avoided cost rates for projects with a capacity of one megawatt or larger. The stipulation described here represents a general agreement between the parties in response to the Commission's orders.

The process began with a meeting on April 11, 1995 to review the utilities' IRP modeling capabilities and to discuss the general elements of a workable methodology. On July 17, 1995, Idaho Power Company filed an application requesting the approval of a methodology for conducting avoided cost rate negotiations with qualifying facilities (QFs) one megawatt or larger, thereby initiating Case No. IPC-E-95-9.

Idaho Power's filing included a description of a proposed methodology along with sample input and output from the IRP model and the resulting avoided costs for a hypothetical project. In response to Staff production requests, Idaho Power made model runs and calculated avoided costs for ten hypothetical scenarios. The various scenarios were intended to evaluate the effects on avoided costs of dispatchability, deferral of on-line dates, the signing of another QF contract during project development, project size, gas price and load growth, in addition to calibration runs. Staff thoroughly evaluated these results to assess the proposed methodology.

On August 29, 1995 Staff conducted the first settlement negotiation between all interested parties. The parties were subsequently invited to submit comments and concerns which they felt should be addressed in a settlement proposal to be drafted by Staff. An additional settlement meeting was held on January 3, 1996. Staff provided a draft of a settlement proposal to interested parties on January 30, 1996.

As a result of the January 3 meeting, the Commission, in the February 9, 1996 Notices of Scheduling in each utility's pending IRP case (Case Nos. IPC-E-95-8, UPL-E-95-5, and WWP-E-95-2), allowed the utilities 45 days in which to make revised IRP filings so that avoided costs would be reflective of changes that had occurred in the interim between IRP filings. Only Idaho Power chose to make a revised filing. A final settlement negotiation and a prehearing conference were held on March 20, 1996. A final draft of the stipulation was provided to the parties on May 7, 1996.

Q. Do you believe the stipulation complies with addition, consideration should also be given to the risks and uncertainties associated with each scenario examined. The least cost combination of resources is selected to meet each scenario. The most likely scenario is identified as the base case plan.

2. An initial simulation analysis using a power supply and/or capacity expansion model chosen by the utility is used to calculate the present value of revenue requirements (PVRR) of the base case resource plan over the lifetime of the proposed QF contract.

3. The proposed QF resource is added to the base case resource plan during all years of the proposed contract. The required description of the QF project includes all data and information needed to model the intended dispatchable or non-dispatchable operation of the project on the power supply system.

4. A second simulation analysis, including the QF resource, is performed which results in an adjustment of the amount and/or timing of the new

resources in the base case plan. The modified plan including the QF purchase is constructed to maintain resource adequacy and system reliability equivalent to that of the base case plan.

5. The PVRR of the modified resource plan including the QF is calculated over the full term of the QF contract, excluding the total purchase costs of the QF resource itself.

6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with the costs of the QF set to zero, from the PVRR of the base case resource plan.

7. Rates for capacity and energy from the QF project can then be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.

Q. Do you believe the methodology results in avoided cost rates that fairly reflect utilities' true avoided costs?

A. Yes, to the extent that they are representative of the costs of avoiding acquisition of the mix of resources in the utilities' IRP. However, utilities frequently acquire resources from the market that are not included in their IRP. The IRP serves as a benchmark for comparison with market alternatives. The resources actually acquired by the utility, whether market resources, company-owned generation or DSM, represent their true avoided costs.

Q. Can the cost of market alternatives be considered using the methodology described in the stipulation?

A. Yes, but only to a limited extent. To the extent a utility is able to make estimates of the future cost and availability of firm and non-firm market resources, the utility can consider them as options in its IRP. However, the cost of market resources can vary considerably and cannot be predicted with certainty. Short-term resources are particularly volatile due to water conditions, seasonal availability and other factors. Consequently, utilities must forecast the price of market resources and update those forecasts frequently to insure that they are accurate.

Q. How is the uncertainty related to market price forecasts any different than the uncertainty in other variables used to calculate avoided cost rates?

A. The primary difference is that market resource acquisitions are typically of only a few years duration, whereas other generating resources or DSM programs have longer lives. Comparing a five-year market purchase for example, to a 35-year generating resource requires that assumptions be made about how resource needs would be met after the five-year purchase expires.

As far as updating market assumptions to reflect current price and availability however, I see little difference between these assumptions and the need to keep assumptions for other variables updated. Admittedly, up until now, market prices have been somewhat difficult to predict since there has been no source for discovering the prices at which wholesale transactions are being made. However, the market is quickly maturing. Electrical price indexes are now available and the electric futures market is now trading. Energy products are also becoming more standardized, making price comparisons easier.

Q. If the market is a better indication of a utility's actual avoided costs, why not use market prices to determine avoided cost rates instead of utility IRPs?

A. I believe it would be premature to use the market to determine utilities' avoided cost rates at this time. Although the market is quickly maturing, I believe it must mature further before it can be reliably used to establish avoided cost rates. Market trading must increase, products must become further standardized, utilities must gain more trading experience, transmission access must be made available to all, and price information must be more readily available.

I believe that it is still appropriate to use utilities' actual resource portfolios in determining avoided costs. Relying solely on the market to establish avoided cost rates would presume that utilities' only source of future resource acquisitions is the market. Although in the foreseeable future utilities may expect most new resources to be acquired from the market, they also plan to acquire new resources through efficiency improvements, system upgrades, DSM, and in the more distant future, construction of new generating plants. I contend that all of these resource options should be considered in the calculation of avoided cost rates. I believe that the avoided cost methodology in the stipulation does that.

Q. Are there any additional issues which you believe need to be addressed?

A. Yes, I believe that the issues of 20-year contract length and fully levelized rates need to be addressed. In the combined avoided cost case, the Commission did not say whether it intends for levelized 20-year contracts to be options available for projects one megawatt or larger.

Q. What is your opinion on 20-year contracts?

A. I believe that 20-year contracts should continue to be available to all QF projects. I concede however, that for the most part, utilities at the present time are not acquiring long-term resources. Except for PacifiCorp's Hermiston contract, utilities are meeting their needs with short-term market purchases. There is no assurance that this will continue indefinitely however. Utilities continue to consider long-term options in their IRPs, and I believe they would pursue those options if the economics and risk were favorable. Consequently, I believe it is reasonable to require 20-year contracts for QFs, since utilities' long-term resource acquisition planning is still primarily based on acquisition of long-lived resources. As long as the rates utilities pay for QF power are based on the utility's avoidance of planned resources, they should be required to offer 20-year contracts if the planned resources have lives of 20 years or more. At the present time, I believe that some utilities may be reluctant to make investments in new company-owned generation due to uncertainties about restructuring and the risks of stranded investments. These concerns, I believe, tend to cause utilities to favor short-term market acquisitions over construction of long-term, company-owned generation.

Q. Do you believe that fully levelized rates are an issue in this case?

A. No, I do not. In the combined avoided cost cases, WWP-E-93-10, IPC-E-93-28, PPL-E-93-5/UPL-E-93-7, and UPL-E-93-3/ PPL-E-93-3, the Commission stated the following in Order Nos. 25882, 25883, and 25884:

> The levelization of avoided cost payments is another tool that this Commission has historically relied upon in encouraging and assisting smaller QFs by providing a cash stream that better enables them to satisfy their debt service in the early years of their contracts. Although we have taken considerable strides toward market-based pricing we find that levelization for projects above 1 MW should be continued. We believe that levelization more accurately reflects the way in which costs are recovered for utility-owned projects. The utilities are directed to provide levelized rates, for all QF projects who desire it, utilizing the same procedure incorporated in the SAR methodology.

I believe that the Commission's statement is clear and speaks for itself.

Q. Do you have any objections to anything contained in the stipulation?

A. No, I do not.

EXHIBIT NO. 101

CASE NO. IPC-E-95-9

RICK STERLING
STAFF

JUNE 14, 1996

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER APPROVING THE METHODOLOGY FOR AVOIDED COST RATE NEGOTIATIONS WITH QUALIFYING FACILITIES LARGER THAN 1 MEGAWATT	CASE NO. IPC-E-95-9 SETTLEMENT STIPULATION

Pursuant to Rules 271-277 of the Commission's Rules of Procedure (IDAPA 31.01.01), the undersigned, including but not limited to the Staff of the Idaho Public Utilities Commission ("Staff"), Idaho Power Company, ("Idaho Power"), the Washington Water Power Company ("WWP"), PacifiCorp ("PacifiCorp"), and Rosebud Enterprises, Inc. ("Rosebud"), herein collectively referred to as the "Parties", by and through their respective counsel of records, hereby stipulate as follows:

I. BACKGROUND

On July 17, 1995, Idaho Power filed an application for an order approving a methodology for conducting avoided cost rate negotiations with qualifying facilities (QF's) 1 MW or larger. Idaho Power's application was docketed as Case No. IPC-E-95-9.

Idaho Power's application was anticipated by the Commission in Order No. 25884 (issued in Idaho Power's most recent avoided cost proceeding, Case No. IPC-E-93-28) in which the Commission stated:

> "We expect the Company to include with its 1995 IRP filing, a more detailed proposal of how the least cost planning based avoided cost methodology will operate. We will treat that filing as a generic discussion of the issue and expect all interested parties, including the other utilities, to intervene and participate so that all issues may be resolved and the methodology can be refined." *id at P. 7.*

On August 14, 1995 in Order No. 26115, the Commission provided public notice of Idaho Power's application and made WWP and PacifiCorp parties to Case No. IPC-E-95-9.

On August 16, 1995, the Commission staff issued a Notice of settlement negotiations to be undertaken pursuant to Rule 272 of the Commission's Rules of Procedure, IDAPA 31.01.01. Subsequently, the following parties intervened in Case No. IPC-E-95-9, and to varying degrees participated in the settlement negotiations that were undertaken pursuant to the August 16, 1995 notice of settlement negotiations: Idaho Power Company, Commission Staff, Washington Water Power Company, PacifiCorp, the Independent Energy Producers of Idaho, Myers Engineering Company, Earth Power Resources, Inc., Irrigation Districts and Rosebud Enterprises, Inc.

Following the August 16, 1995 Notice, settlement negotiations were undertaken at the Commission's offices on August 29, 1995, January 3, 1996, and March 20, 1996. As a result of the settlement negotiations, the Parties developed a methodology for conducting avoided cost rate negotiations which is entitled "Staff's Proposed Avoided Cost Methodology for Projects Larger than 1 MW, Case No. IPC-E-95-9" ("Staff Proposal"). The Staff Proposal methodology was the subject of both written comments and substantial discussions at the settlement conferences. The most recent version of Staff's Proposal is attached hereto as Exhibit 1. In conformance with the Parties' settlement discussions, the Parties hereby submit this Settlement Stipulation to the Commission and request that the Commission accept and approve the attached Exhibit 1 Staff Proposal as the methodology for computing avoided costs and for conducting avoided cost rate negotiations for QF projects 1 MW and larger.

II. AGREEMENTS

(1) The Parties have negotiated this Settlement Stipulation and Exhibit 1 as a part of a settlement proceeding. Each of the Parties may not agree with all of the provisions of Exhibit 1 but they are each willing to accept Exhibit 1 as a reasonable compromise of contested positions. If the Commission does not accept this Stipulation and Exhibit 1 in their entirety, without modification, it will be withdrawn and shall be without any force or effect.

(2) By executing this Stipulation, the Parties agree to recommend that the Commission issue an order adopting Exhibit 1 as the methodology for computing avoided costs and

for conducting avoided cost rate negotiations for QF projects 1 MW and larger and agree to file testimony in support of the Stipulation.

(3) This Settlement Stipulation may be signed in counterparts.

III. ADDITIONAL ISSUES

As Exhibit 1 evidences, the Parties were able to resolve the vast majority of the issues that are associated with establishing the IRP methodology. Nevertheless, there were several issues raised during the negotiations upon which the Parties were unable to achieve consensus. The unresolved issues generally relate to rate levelization and length of contract. On those issues, the positions of the Parties fell into two general categories. One group, primarily the utilities, maintained that contract length and rate levelization should be individually negotiated based on the utilities' specific IRPs and the individual characteristics of the project. In addition, the utilities argued that long term contracts must include a mechanism to allow periodic rate adjustments to track changes in market prices for electric capacity and energy. The other position, as expressed primarily by QF developers, was that the Commission should require that QF developers have the option of obtaining long term contracts containing levelized or non-levelized avoided cost payments. In addition, the parties were unable to agree on the treatment of non-deferrable resources within the methodology. The consensus of the Parties was that the Commission could address all unresolved issues at the hearing scheduled for consideration of the Settlement Stipulation.

DATED This 6th day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By: ______________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By: ______________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By: ______________________________
R. Blair Strong

PACIFICORP

By: ______________________________
John M. Eriksson

DATED This 3rd day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:______________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:______________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By:______________________________
R. Blair Strong

PACIFICORP

By:______________________________
John M. Eriksson

DATED This 7th day of ~~May~~ June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:______________________________

Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:______________________________

Barton L. Kline

WASHINGTON WATER POWER CO.

By: R. Blair Strong

R. Blair Strong

PACIFICORP

By:______________________________

John M. Eriksson

DATED This 5th day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:______________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:______________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By:______________________________
R. Blair Strong

PACIFICORP

By:______________________________
John M. Eriksson

DATED This _____ day of _____________, 1996.

INDEPENDENT ENERGY PRODUCERS
OF IDAHO

By: ____________________
Peter J. Richardson

MYERS ENGINEERING COMPANY

By: ____________________
John Runft

EARTH POWER RESOURCES, INC.

By: ____________________
Peter J. Richardson

IRRIGATION DISTRICTS

By: ____________________
Don A. Olowinski

ROSEBUD ENTERPRISES, INC.

By: ____________________
Owen H. Orndorff

Exhibit No. 101
Case No. IPC-E-95-9
R. Sterling, Staff
06/14/96 Page 9 of 24

DATED This _____ day of _____________, 1996.

INDEPENDENT ENERGY PRODUCERS OF IDAHO

By:______________________________
Peter J. Richardson

MYERS ENGINEERING COMPANY

By:______________________________
John Runft

EARTH POWER RESOURCES, INC.

By:______________________________
Peter J. Richardson

IRRIGATION DISTRICTS

By:______________________________
Don A. Olowinski

ROSEBUD ENTERPRISES, INC.

By:______________________________
Owen H. Orndorff

STAFF'S PROPOSED AVOIDED COST METHODOLOGY FOR PROJECTS LARGER THAN ONE MEGAWATT CASE NO. IPC-E-95-9

Introduction

On January 31, 1995, the Idaho Public Utilities Commission issued Order Nos. 25882, 25883, and 25884 which required that utilities utilize their Integrated Resource Plans (IRPs) to establish avoided cost rates for projects larger than one megawatt. The Commission stated the following in its orders:

> We believe that the adoption of the least cost planning methodology is consistent with our goal of maintaining a regulatory climate that allows our electric utilities to retain their advantageous posture in a marketplace that is likely to become increasingly competitive. This will ultimately work to the advantage of ratepayers in the form of rates lower than would otherwise be in effect. By treating QFs [Qualifying Facilities] in the same manner as utility acquired resources, we are further removing the shelter that has been constructed around the QF industry. Requiring those projects to prove their viability by market standards insures that utilities will not be required to acquire resources priced higher than would result from a least cost planning process. Ratepayers will not be disadvantaged and QFs will be treated fairly and consistently with the requirements and goals of PURPA.

See, e.g. Order No. 25884 at page 6.

In accordance with Order No. 22299, all utilities are required to prepare IRPs biennially. The following elements are included in the development of the IRP:

1. Integrated evaluation of all resource options;
2. Least cost selection criterion for the resource plan;
3. Inclusion of environmental impacts and external costs of resources;
4. Analysis of planning uncertainties and risks; and
5. Public involvement in the planning process.

An IRP forms the basis for utility decisions regarding the timing, quantity, and type of future resource acquisitions. The end result of integrated resource planning is a set of resource options which represent the least cost means of meeting expected future loads considering a reasonable range of planning uncertainties and risks. The set of options with the highest probability of having the least cost, and which has an acceptable level of risk, is usually referred to as the "base case" plan. The base case plan is the starting point of the analytical process described in this document for determining project-specific avoided cost rates for QF projects larger than 1 MW.

In the past, utilities have submitted IRPs to the Commission for filing, but no formal process has been in place for detailed review or approval of the IRPs. However, as a result of their increased utilization and importance as something other than a planning document, utilities should expect their plans to be scrutinized more carefully in the future. The Commission Staff intends to conduct thorough reviews of the plans, and anticipates that hearings may be held to provide an opportunity to seek comment. As in the past, utilities should not be bound to follow their IRP without exception. In fact, when good cause is shown, they should be expected to deviate from it. But absent good cause, they should now expect to be held to it more closely. More importantly, the IRP will establish the standard against which all resource acquisitions will be judged, both utility and non-utility owned alike.

Public participation is required in the preparation of utility IRPs. Developers and their representatives shall be welcome to participate in any public meeting related to the development of a utility IRP. It is the utility's responsibility to offer invitations to participate to a broad cross section of interested parties. The responsibility to actually participate lies with the interested parties.

The opportunity for developers or other interested parties to ultimately influence the calculation of avoided cost and the rates for QF projects that are derived from that calculation, is in the development of a utility's IRP, not in the application of the avoided cost methodology. The IRP is the source of all inputs used in the calculation of avoided costs. It is the real basis for calculating avoided cost rates. Once the avoided cost methodology is established, Staff does not expect a hearing or other formal Commission proceeding to be initiated each time a utility's avoided costs are calculated.

General Methodology

PURPA defines avoided cost as "the cost to an electric utility of electrical energy or capacity or both which, but for the purchase from such cogenerator or small power producer, such utility would generate itself or purchase from another source" *18 CFR, § 292.101.*

As explained by FERC:

> This definition is derived from the concept of "the incremental cost of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities. One way of determining avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy costs of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy costs of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. (Order No. 69 [45 Fed. Reg. 12,216, 1980]).

In the proposed methodology, the avoided cost of a QF project is determined as the cost which the utility would avoid if it purchased power from the QF, rather than acquiring the same power from the resources selected in its base case resource plan. Put another way, the avoided cost of the QF project is the difference in the present value of revenue requirements (PVRR) between the base case resource plan and a modified resource plan that includes the QF resource. The avoided cost determination involves the following steps:

1. An IRP is prepared for the utility. The IRP should consider a range of load forecasts for various sets of possible economic conditions. The IRP should also consider all possible resources for meeting load, both supply side and demand side. In addition, consideration should be given to the risks and uncertainties associated with each scenario examined. The least cost combination of resources is selected to meet each scenario. The most likely scenario is identified as the base case plan.

2. An initial simulation analysis using a power supply and/or capacity expansion model chosen by the utility is used to calculate the PVRR of the base case resource plan over the lifetime of the proposed QF contract.

3. The proposed QF resource is added to the base case resource plan during all years of the proposed contract. The required description of the QF project includes all data and information needed to model the intended dispatchable or non-dispatchable operation of the project on the power supply system (see pps. 9-10 for a list of data and information needed from QFs).

4. A second simulation analysis, including the QF resource, is performed which results in an adjustment of the amount and/or timing of the new resources in the base case plan. The modified plan including the QF purchase is constructed to maintain resource adequacy and system reliability equivalent to that of the base case plan.

5. The PVRR of the modified resource plan including the QF is calculated over the full term of the QF contract, excluding the total purchase costs of the QF resource itself.

6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with costs of the QF set to zero, from the PVRR of the base case resource plan.

7. Rates for capacity and energy from the QF project can now be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.

IRP Data for Avoided Cost Calculations

Many of the same variables must be chosen and many of the same assumptions must be made by each utility in the development of their IRP. For example, each utility must make assumptions about inflation, the price of natural gas, or the cost of building a coal plant. Some planning variables will probably be the same for all utilities, but many will be different. In the past, the Commission has specifically determined both generic and company-specific variables used to calculate avoided cost for large projects. With implementation of the IRP methodology, the Companies will be responsible for determining these variables. As long as the values and assumptions fall within a reasonable range, utilities are free to choose values most appropriate for their own situation. It follows then, that different utilities will likely assume different values for the same variables. No variables will be considered generic; all variables will be utility specific, as are the utilities' IRPs. In granting utilities the freedom to select their own variables, utilities should be aware that they will be required to analyze their own resources on an equal footing with QF resources.

Portfolio Resources

The resource portfolio of each utility should include a variety of both supply and demand side resources. Market purchases also represent a future supply option, and will likely comprise an increasingly larger portion of utilities' resources in the future. In fact, for some utilities, market purchases may constitute the primary source of new resources. The cost of market resources, to the extent a utility relies on them, should be one component in determining utilities' avoided costs. However, in order for market resources to be considered in the determination of avoided costs in an IRP-based methodology, those market resources must be included in the IRP. Any market purchases made that are not anticipated in the IRP cannot be used in the calculation of avoided costs. However, due to the fact that Pacificorp's RAMPP-4 calibration of its IPM model does not provide for the IPM's calculation of avoided costs, Pacificorp will be allowed to propose modifications to the IPM calibrations for the purpose of determining avoided costs, subject to Commission approval in Case No. IPC-E-95-9.

Predicting the price and availability of market resources, particularly in the long term, is difficult and uncertain. Consequently, forecasts made in the IRP should be firmly based on sound reasoning and analysis. The degree of planned reliance on market resources should be a matter of interest to ratepayers, shareholders, the Commission and the public. Review of the utilities' planned reliance on the market however should occur in the context of an IRP filing, not in an avoided cost proceeding.

Demand side resources to which the utility has made a firm commitment should be considered as reductions in the load forecast rather than as supply side resources, in part, to discourage double counting.

Load and Resource Forecasts

Forecasts of electricity load growth are made by each utility at two-year intervals as a part of IRP filings. These forecasts serve as the basis for avoided cost calculations. Staff contends that only known, measurable, and easily documented changes should be made to the forecasts during the interim periods between required filings. For example, discrete changes in load that could be traced to the addition or loss of a single major customer would be a known, measurable, and easily documented change. The signing or expiration of a power sales or exchange agreement would also be a known, measurable, and easily documented change, as would the signing of a new QF contract.

On the other hand, a load change due to population growth may be known, but would not be easily measured or documented.

Updating IRP Data

For the most part, utilities' resource plans as set forth in their IRPs should guide resource acquisition activities, including the resource cost effectiveness and avoided cost determinations, until replaced by subsequent IRPs. One of the goals of this avoided cost methodology is to achieve a dynamic resource evaluation process that recognizes changes in loads, technologies, costs, availabilities, and economic conditions so that utilities' avoided costs are accurately determined. However, QF developers seek to maintain some stability of avoided cost rates so that they are able to plan projects with some degree of certainty. In addition, the public must have the opportunity to participate in the planning process to provide input regarding variables that are ultimately used in each utility's IRP.

To achieve some balance between these competing objectives, this methodology allows periodically scheduled changes to some variables, while keeping other variables fixed between IRP filings. In essence, there will be a core set of variables that are used in the IRP and in the determination of avoided cost rates, but a subset of those variables will be changed periodically for the purpose of accurately calculating avoided costs. Every two years, a new IRP will be filed with new core variables and variables that will be adjusted periodically.

Generally, variables which are acquired from independent third party sources and which are updated at regular intervals can be adopted by utilities for use in avoided cost calculations. However, the same source must be consistently used. Any change in the source of the data must also be agreed to by the Commission. Semi-annual updates will be allowed for the following based on verifiable forecasts:

- Escalation rates for capital costs;
- Escalation rates for O&M expenses;
- Escalation rate for fuel prices;
- Fuel prices.

If multiple sources are used to establish values for these variables, such as for gas prices, or if a utility wishes to make adjustments to values in consideration of regional circumstances, the utility should propose the sources and adjustment mechanisms at the time of their next IRP filing for consideration by the Commission. The utility should consistently use the same sources and adjustment mechanisms in the future for determining avoided cost rates unless changes are authorized by the Commission.

At such time as easily verifiable information is readily available from independent third party sources, the following variables may also be updated semiannually:

- Wholesale power price;
- Wholesale power price escalation rates;
- Wholesale power available for purchase.

The variables must be reflective of the same wholesale power products used for analysis in the IRP, so that no adjustment of the variables is needed before they can be used in the IRP or in calculating avoided cost rates. Permission must be obtained from the Commission before these variables may be updated on a semi-annual basis for avoided cost purposes.

Staff recommends that updates to resource portfolio data, such as plant capital costs, operation and maintenance costs, heat rates, generation capacities, plant factors, economic life, etc. not be allowed except during biennial IRP submissions. Updates to load forecasts, except for known and measurable changes as discussed previously, should also not be allowed except during IRP submissions.

Variables that go into calculating utilities' before and after tax cost of capital should be updated on a regular basis also. Staff proposes that these variables be updated biennially upon submission of new IRPs. Utilities may use estimated values for weighted cost of capital, and should assume a hypothetical capital structure reflecting the typical degree of leveraging for electric utilities with "A" grade bond ratings. Alternatively, utilities may use the weighted cost of capital as established in the utility's most recent general rate case.

To the extent they affect resource costs, the passage of new laws and the imposition of new regulations may trigger changes in variables. Staff recommends Commission approval be required however, before variables can be changed for the purpose of determining avoided costs as a result of these types of factors.

Publication of Rates

In order to provide benchmark avoided cost rates which potential QF developers can use for planning purposes, Staff recommends utilities be allowed to publish avoided cost rates for hypothetical projects. The rates should be published semiannually at the time changes in variables are submitted to the Commission. The rates should be for hypothetical 10 MW, 20 MW, and 40 MW gas-fired, non-dispatchable projects with 100% capacity factors. The rates would be non-binding on the utility and would serve only as an approximation of rates for similar projects. Alternatively, utilities may forego publishing hypothetical rates if they can provide, within 10 working days of receiving a request, approximate rates based on IRP model runs.

Rate Quotations

Before a developer requests a rate quotation from a utility, Staff recommends a meeting be held between the utility and the developer to discuss details of the project and to discuss the process for calculating rates. Once a request for binding rates is made, Staff contends the utility should respond to the request within 30 days. In order to receive a firm quotation, the developer must be able to provide the utility with the following information:

1. Developer name;
2. Proof of QF status (notice of self-certification will suffice);
3. Project location, and point of power delivery if the project is located outside of the state of Idaho;
4. Project size, including ambient conditions for this rating;
5. Capacity factor and proposed time shape of production;
6. Fuel source and mode and route of delivery;
7. Whether fuel supply is firm or non-firm and whether there are any constraints affecting its availability or dependability;
8. Proposed contract term (final term — length and timing — to be subject to negotiation);
9. On-line month and year;
10. Maintenance schedule;
11. Other factors affecting operation;
12. Wheeling utility(ies) between point of interconnection and point of delivery;
13. Expected delivered energy by month during heavy and light load hours;
14. Guaranteed minimum capacity.

If a project desires to be operated according to a negotiated schedule or dispatched under specific circumstances, the utility may request additional information as needed in order to provide an accurate rate quotation.

In response to a request for rates, Staff believes the utility should provide the difference in cost by year between the base case plan and the same plan with the QF included. Using an acceptable methodology, utilities should separate the annual differences in costs into capacity and energy components.

Actual contract terms should be negotiable between the utility and the developer, subject to the rules and guidelines set forth in this document. Rate quotations should be effective for a minimum of 120 days. Except for the signing of other QF contracts, the acquisition of other generating resources, or major discrete changes in load, under no other circumstances should the rate be changed during the 120-day period, even if changes occur in variables. When providing a rate quotation, utilities should be obligated to divulge whether any other rate quotation has been made for another project and is still within its 120-day effective period. In addition, utilities must agree to meet with the developer within 15 working days after the date on which the rate quotation is made.

Access to Utility Models

Utilities should be allowed to utilize any model they desire in calculating avoided costs, as long as the same model is used in the development of the utility's IRP. If the utility is required to sign a licensing agreement for use of the model that restricts its use to utility personnel only, then access to the model may be restricted to the Commission Staff, subject to restrictions of the licensing agreement. However, in order to minimize the "black box" effect created when rates are calculated by the utility using proprietary software, utilities must be willing to accommodate requests from developers and Commission Staff for a reasonable number of model runs for alternative project plans. The model runs must be meaningful and requested in support of negotiating a commercially viable contract. Staff recommends that no fee be charged by the utility for these model runs. Furthermore, utilities should have the obligation to assist developers in optimizing their projects so that developers maximize the value of their project to the utility's system. To do so is in the best interests of both the developer and the utility.

Seasonalized and On-Peak/Off-Peak Rates

Staff believes utilities should be permitted to continue to offer different rates for peak and off-peak hours, and to continue to seasonalize rates (where currently allowed for Idaho Power and Washington Water Power) using the same seasonalization factors allowed for projects smaller than 1 MW.

rs:gdk:jo:bp/ipce959c.avc/h /comments/i(5/28/96)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 29th day of May, 1996, I served a true and correct copy of the within and foregoing SETTLEMENT STIPULATION, to the following individuals by the method indicated below, and addressed to the following:

Brad Purdy Idaho Public Utilities Commission 472 W. Washington Statehouse Boise, ID 83720	~~X~~ Hand Deliver X U.S. Mail ___ Overnight Mail ___ Facsimile
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Barton L. Kline

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF JUNE 1996, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING** IN CASE NO. IPC-E-95-9, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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