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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	)	CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KARL BOKENKAMP

Q. Please state your name and business address.

A. My name is Karl Bokenkamp and my business address is 1221 West Idaho Street, Boise, Idaho.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Director of Operations Strategy.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Mechanical Engineering from the University of Illinois at Urbana-Champaign in 1980. In 1995, I earned a Master of Engineering Degree in Mechanical Engineering from the University of Idaho and, in 2010, I received a Master of Business Administration from Boise State University. I am a registered Professional Engineer in the state of Arizona, and I have attended the Stone & Webster Utility Management Development Program and the University of Idaho's Utility Executive Course.

Q. Please describe your work experience with Idaho Power.

A. I was employed by Idaho Power in 1995 as the Director, and then Manager, of Thermal Production. In this position, I was responsible for managing Idaho Power's Thermal Production Department. Primary responsibilities of the department included oversight and control of Idaho

Power's ownership shares in its three jointly owned coal-fired generation resources, Bridger, Boardman, and Valmy, and their associated fuel supplies.

In 2001, I accepted a new position as the Manager of Power Supply Planning and was later promoted to General Manager of Power Supply Planning. In this position, I was responsible for building and managing Power Supply's Planning Department. This department's responsibilities included operational planning, load forecasting, stream flow forecasting, integrated resource planning, cogeneration and small power producer contract management, water management/river operations, and gas and coal contract management.

In 2006, I was promoted to the position of General Manager, Power Supply Operations and Planning. This position added operational responsibilities, which included asset optimization, wholesale electricity, and natural gas transactions from real-time through multi-year deals as well as real-time operations and scheduling.

In 2010, I became Idaho Power's Director of Operations Strategy. In this position, I am responsible for unifying Idaho Power's operational strategy, including sustainability, investigating opportunities, trends and technologies that may impact the utility business, and positioning the Company for continued success in its rapidly changing industry.

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

A. I will present Idaho Power's proposal for modifications to the existing Integrated Resource Plan-("IRP") based avoided cost pricing methodology. There are two primary changes I am proposing; they are (1) a change in the methodology used to determine the energy component of avoided cost and (2) a change in the resource type used to establish the capacity component of avoided cost.

CURRENT METHODOLOGIES

Q. What avoided cost methodologies are currently approved by the Idaho Public Utilities Commission ("Commission") for determining avoided cost rates for Qualifying Facility ("QF") contracts?

A. As discussed more fully in Company witness Mark Stokes' testimony, the Commission has approved two methodologies for establishing a utility's avoided cost and setting rates for QF contracts entered into pursuant to Public Utility Regulatory Policies Act of 1978 ("PURPA") regulations. The two methodologies are the Surrogate Avoided Resource ("SAR") methodology and the IRP methodology.

Q. What is the SAR methodology?

A. The SAR methodology is a methodology which uses a surrogate or proxy resource to set published, or standard, avoided cost rates. As currently implemented in Idaho, the SAR methodology uses a natural gas-fired combined cycle combustion turbine as the surrogate resource for establishing rates for QF contracts. Published, or standard, rates are required by Federal Energy Regulatory Commission for projects up to 100 kilowatts ("kW"). Published rates in Idaho are available to wind and solar QFs with a nameplate capacity up to 100 kW and all other QFs with an output of up to 10 average megawatts ("aMW") per month. All QF projects over 10 aMW and all wind and solar QF projects over 100 kW must use the IRP-based methodology, which provides a basis for developing a negotiated rate.

Q. Does the Company have any recommendations regarding the use of the SAR methodology?

A. Yes. Idaho Power proposes that the Commission discontinue use of the SAR methodology for establishing avoided cost rates, and instead proposes that the Commission utilize the IRP-based methodology to establish all QF avoided cost rates. The rationale for this position is set forth in more detail in the testimony of Company witness Stokes.

Q. What is the IRP methodology?

A. The IRP methodology is the second of the two methodologies the Commission has approved for establishing a utility's avoided cost pursuant to PURPA. Generally, the IRP-based methodology calculates the projected future cost of Idaho Power's preferred resource portfolio without the QF seeking contract pricing, and then again with the QF seeking contract pricing added to the resource portfolio at zero cost. The difference in cost between the two analyses is divided by the projected QF generation to determine the energy component of avoided cost. The capacity component of avoided cost is determined based on the characteristics of the QFs generation, and it is added to the energy component. This methodology produces an estimate of the utility's avoided cost, which is then used as the starting point for negotiating QF contract pricing. Project-specific characteristics are utilized in the pricing analysis and a number of other factors can enter into contract negotiations. Idaho Power's current approach for implementing the IRP methodology was presented to the parties of this case on December 15, 2011, in the Commission's hearing room, and is explained in greater detail in Company witness Stokes' testimony and Stokes' Exhibit No. 3.

Q. Is it Idaho Power's position that the IRP methodology is a better estimation of avoided cost than the SAR methodology?

A. Yes. The IRP methodology as currently implemented is a significant improvement over the SAR methodology. It is a far more accurate approximation of avoided cost than the more generic SAR methodology. As currently implemented, the IRP methodology begins to take into account some aspects of need, value, and timing of the QFs proposed generation when establishing the avoided cost rates. One of the most important improvements of the IRP methodology over the SAR methodology is that the IRP methodology incorporates several of the resource-specific characteristics of the proposed QF generation. These include the QF's specific generation output profile, a resource specific capacity factor, the timing of anticipated generation, and a capacity credit based on the anticipated amount of capacity provided during Idaho Power's projected peak-load hours.

Q. Do you have any recommendations for changing the current implementation of the IRP methodology?

A. Yes. While the IRP methodology as currently implemented by Idaho Power is a significant improvement over the SAR methodology, it still has a number of problems that result in significant harm to Idaho Power's customers.

Q. Could you please provide us with some examples of the problems that exist with the current implementation of the IRP methodology?

A. Yes. Although the IRP methodology is a significant improvement over the SAR methodology it does have several flaws that disconnect it from the definition of avoided cost as set forth in federal regulations, which is what the IRP methodology is supposed to be approximating. For example, as currently implemented by Idaho Power:

1. The avoided cost produced by the current IRP methodology relies too heavily upon forecasts of future market prices. Under the current approach, customers take on a significant amount of a market price risk that, but for the QF purchase, they normally would not experience as a customer of Idaho Power.

2. The avoided cost produced by the IRP methodology, is largely predicated on making surplus sales at the future market prices developed within the AURORA model. This deviates from the definition of avoided cost, which is focused on the incremental cost to an electric utility of displaced generation or purchases. Projected revenue from surplus sales is never mentioned in the federal regulation definition of avoided cost.

3. The present IRP methodology is somewhat static with respect to changes in the resource portfolio. What I mean by this is that the preferred resource portfolio used in the IRP methodology is not updated between IRP cycles. Consequently, the impacts of newly signed QF contracts on Idaho Power's avoided cost are not reflected in subsequent avoided cost calculations until the preferred portfolio is updated in the next IRP cycle.

Q. You have mentioned the definition of avoided costs several times, what are you referring to?

A. I am referring to the definition of avoided cost found in federal regulations, 18 C.F.R. § 292.101(b)(6).

Q. How do the federal regulations define avoided cost for purposes of PURPA QFs?

A. Federal regulation defines avoided cost as follows:

> Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

18 C.F.R. § 292.101(b)(6).

Q. What is significant about this definition?

A. First of all, the concept of identifying <u>incremental costs</u> the utility would incur, but for the QF purchase, is clearly significant. This concept is the key to developing an avoided cost methodology that accurately calculates avoided cost as contemplated by, and required by, federal law. Another significant aspect of the definition is the absence of any reference to sales in determination of avoided costs.

Q. Do you have any other observations or comments of significance about the definition of avoided cost?

A. Yes. Keeping with the definition of avoided cost, what Idaho Power is trying to determine is the <u>incremental</u> <u>costs</u> to an electric utility which, but for the purchase from the QF, such utility would generate itself or purchase from another source. At a very basic level, this definition implies that the utility needs to incur, or at least expect to incur, a cost in order to have an avoided cost. With this in mind, Idaho Power's proposed revision to the IRP methodology focuses on identifying the <u>incremental costs</u> that its system would incur, but for the QF purchase, to <u>generate power</u> itself or to <u>purchase power</u> from another source. This directly comports with the definition of avoided cost from federal regulations. Since incremental costs change, a proper application of the Code of Federal Regulation's definition of avoided cost results in (1) an hour-by-hour analysis of the period of interest to determine the avoidable incremental cost during each hour and then (2) a methodology to convert the hourly incremental costs into avoided cost rates. Idaho Power's proposed avoided cost methodology addresses both of these items.

PROPOSED IRP METHODOLOGY MODIFICATIONS

Q. Please describe Idaho Power's proposed modifications to the IRP based methodology.

A. Idaho Power's proposed modifications to the IRP methodology are as follows:

1. A change in the methodology used to determine the energy component of avoided cost. This change is proposed in order to align the methodology with the federal regulation's definition of avoided cost and thereby establish an avoided cost of energy based on <u>the incremental costs the utility would incur, but for the addition of the QF resource</u>;

2. A change in the resource type used to establish the capacity component of avoided cost. This change is proposed to align the methodology with the actual costs of capacity that are avoided; and

3. Implementation of a queuing process to (1) establish a QF's position in line and (2) identify the QF projects included in Idaho Power's resource portfolio for determining avoided costs in subsequent requests for QF

contract pricing. Idaho Power's resource portfolio, for purposes of calculating a future avoided cost, can change whenever a QF project enters the queue if that QF is considered as a part of the resource portfolio. Accordingly, the avoided cost of energy and capacity can change for each new QF as a result of the capacity and energy provided by all projects in Idaho Power's portfolio, including any QFs already in the queue. The fact that avoided costs can change as new QF resources are added to the portfolio must be taken into account if avoided cost is to be determined properly.

AVOIDED COST OF ENERGY

Q. Please describe in more detail the particular changes you are proposing to the current implementation of the IRP methodology.

A. As discussed in Company witness Stokes' testimony, the IRP methodology includes a rate for both the avoided cost of energy and the avoided cost of capacity. In order to align with the required definition of avoided costs, Idaho Power proposes that the avoided cost of energy be based upon the incremental energy cost the utility would incur, but for the QF output. In order to do this, Idaho Power proposes to use the AURORA model to determine the highest displaceable incremental cost being incurred during each hour of the QF's proposed contract term. In Idaho

Power's proposal, displaceable incremental costs are limited to (1) incremental costs for Company-owned thermal resources (Bridger, Boardman, Valmy, Langley Gulch, and the gas-fired peakers) that are on-line and operating at above their minimum load level, (2) the incremental cost associated with longer-term firm purchases, and (3) the incremental cost of market purchases as determined by AURORA.

Q. Could you explain what you mean when you say that displaceable incremental costs are limited to the incremental costs for Company-owned thermal resources or the incremental costs associated longer-term firm purchases or market purchases?

A. Yes. First, for a resource to be "displaceable" it has to be on-line and capable of staying on-line and further reducing its output. Second, the displaceable incremental costs associated with any longer-term firm purchases or market purchases are set at the market clearing price as determined by the AURORA model on an hour-to-hour basis.

Q. How are longer-term firm, non-PURPA, power purchases treated in the model?

A. Longer-term firm purchases, such as the PPL EnergyPlus Power Purchase Contract, will be included in Idaho Power's resource portfolio in the AURORA model to determine the avoided cost of energy, and they will be modeled as must run resources. However, during any hours when purchases under these contracts are flowing, the market clearing price determined in AURORA will be used to establish the displaceable incremental cost associated with that firm purchase. For example, if the firm purchase is resold at market price and the QF generation is accepted, then the incremental cost avoided is the net proceeds from the resale of the firm purchase after any transaction-related costs such as transmission costs, losses, etc. However, to simplify the analysis, Idaho Power is proposing to disregard the transaction-related costs and use the AURORA market clearing price to set the displaceable incremental cost for long-term firm, non-PURPA, power purchases whenever they are flowing.

Q. You have mentioned that displaceable incremental costs are limited to the incremental costs for Company-owned thermal resources and the incremental costs associated with longer-term firm purchases or market purchases. What about Idaho Power's hydroelectric projects – are their incremental costs considered in the methodology Idaho Power is proposing?

A. No. The direct operating expense for Idaho Power's hydroelectric resources during 2011, including an estimate of depreciation (which was over $15 million), was approximately $31 million. Idaho Power's 2011 hydroelectric generation was approximately 11 million megawatt-hours ("MWh"). This gives Idaho Power an operating cost in 2011, including depreciation, of approximately $3/MWh. Without considering depreciation, hydro operating expenses are less than $1.50/MWh, and variable costs are even less. Since Idaho Power typically has one or more thermal units on-line, and since the incremental cost of the thermal units always exceed the variable cost of the hydro units, I have not considered the incremental cost of Idaho Power's hydroelectric resources in this methodology. If opportunity costs are included and shifting hydro generation from one time period to another is considered, the analysis becomes more complicated. In a practical sense, the incremental cost avoided in any given hour, as a result of displacing a MWh of hydroelectric generation during that hour, is very small. With this in mind, the methodology I am proposing does not attempt to incorporate the incremental cost of Idaho Power's hydroelectric projects.

Q. Are there times when the incremental cost calculated with Idaho Power's proposed methodology goes to zero?

A. Yes, and this is not unrealistic. Considering the minimum load levels established for the thermal generating resources, and the amount of non-dispatchable QF generation on Idaho Power's system, there may be hours during low load periods when Idaho Power's avoidable incremental costs are zero. In fact, there could be times when Idaho Power's avoided incremental costs would be negative. For example, if loads are low and a thermal unit is shutdown in order to accept additional QF generation and then the output of the intermittent QF generation drops off, additional costs could be incurred if the previously shutdown thermal unit is unavailable to replace the QF output. A more expensive unit may have to be started or more expensive market purchases may be required. In either situation, additional costs are incurred.

Q. Do you have an example?

A. Yes. As an example, out of a total of 157,776 hours in an AURORA simulation for a 22 megawatt ("MW") wind project, the new methodology assigned an avoided cost of $0/MWh in 1,563 hours. This works out to about 1 percent of the time, or 87 hours per year.

Q. Would Idaho Power be able to sell the output from the QF during that hour?

A. Maybe, but if the model has the Company's available coal-fired units at their minimum loads and if there are not transmission constraints limiting their output, then there likely is not a demand for energy at the coal-fired units dispatch prices.

Q. Can you provide an example to demonstrate your proposed change in the way the avoided cost of energy is calculated?

A. Yes. Idaho Power can look at several different hypothetical cases to illustrate how the methodology will assign incremental costs. For example, in case 1 load is 2,000 MW, the system is balanced, Idaho Power has one or more thermal units in operation, and there are no purchases; in case 2, identical conditions exist with the following exception, a "new" QF generates and delivers one MWh of energy to Idaho Power's system. One of two things must happen for the system to remain balanced – either Idaho Power's resources must reduce output by one MWh or one MWh is sold into the market. If a sale is made, there is no incremental cost to Idaho Power that is avoided. However, if the output of Idaho Power's highest cost on-line thermal resource can be reduced by one MWh, then there is an incremental cost to Idaho Power that can be avoided. If the incremental costs of that unit are $17/MWh for fuel and $3/MWh for variable operations and maintenance, then the avoided cost for that MWh of QF energy is $20/MWh ($17/MWh + $3/MWh).

If the on-line thermal resources are at their established minimum load levels, thermal generation cannot be further reduced without taking a unit off-line. In this situation, if a QF produced an additional MWh and Idaho Power took a thermal unit off-line to accommodate the QF generation and then later had to restart the unit because of reduced QF output or increased load, the additional MWh of QF generation could have resulted in Idaho Power actually incurring more costs than it would have without receiving the QF generation. Under these circumstances, the methodology assumes generation at one of the hydro projects is reduced and water is spilled. In this case, the cost to Idaho Power if it had generated that MWh of energy at one of its hydro projects is essentially zero and the incremental cost avoided is set at $0/MWh for that hour.

Assuming a different hypothetical situation, again using two cases: in case 1, load is 3,000 MW, the system is balanced, Idaho Power has one or more thermal units in operation, and purchases are being made to serve load; in case 2, identical conditions exist with the following exception, a "new" QF generates and delivers one MWh of energy to Idaho Power's system. For the system to remain balanced in case 2, one of three things must happen — Idaho Power's resources must reduce output by one MWh, market purchases must be reduced by one MWh, or one MWh must be sold into the market. Like before, if a sale is made, no incremental costs are avoided as a result of receipt of the QF energy. However, if the output of one of Idaho Power's thermal resources is reduced by one MWh, or if the amount of market purchases are reduced by one MWh, then it is possible to identify an incremental cost that the utility would have incurred, but for the "new" QF purchase. In this instance, the incremental cost avoided during that hour is the <u>greater</u> of (1) the incremental cost of the most expensive displaceable thermal resource on-line or (2) the market clearing price during that hour. For example, if the incremental cost of the most expensive thermal unit on-line is $20/MWh (the same unit described earlier) and the most expensive market purchases during the same hour is $30/MWh, then the avoided cost for that MWh of energy is $30/MWh. Alternatively, if the incremental cost of the most expensive thermal unit on-line is $60/MWh (e.g., a simple cycle combustion turbine ("SCCT") with 11,000 Btu/kWh heat rate, $5.00/MMBtu natural gas, and variable operations and maintenance ("O&M") costs of $5/MWh) and the cost of market purchases during the same hour is $30/MWh, then the avoided cost for that MWh of energy is $60/MWh.

Q. Could you summarize how Idaho Power's proposed modification to the calculation of the avoided cost of energy works?

A. Yes. To calculate the energy component of avoided cost, the incremental cost for each hour of the proposed QF contract term is determined by analyzing the results of the AURORA analysis as described above. The result of that analysis is a time series of displaceable incremental or avoided costs - one for each hour of the proposed contract term. This time series of hourly avoided costs is then multiplied by the QF's supplied hourly generation profile; e.g., avoided cost in hour 1 x QF forecast generation in hour 1, avoided cost in hour 2 x QF forecast generation in hour 2, etc. These products are then summed over heavy load and light load hours of each month and divided by the corresponding forecast QF generation. The result is a heavy load and light load price for each month of the contract term.

Q. How is this any different than the way the avoided cost of energy is currently calculated?

A. Under the current methodology, the power supply costs of Idaho Power's resource portfolio are determined by the AURORA model without inclusion of the proposed QF. Then the AURORA model is run a second time with no modifications to the dispatch of Idaho Power's resources (e.g., Bridger, Boardman, Valmy, Hells Canyon, and all other resources produce the same hourly output they did in the first AURORA simulation) and the proposed QF's generation is added to the resource portfolio at zero cost. Because the load and operation of Idaho Power's resources are the same, the QF generation is used for one of two things — it either displaces a market purchase or supplies a market sale.

Under the new methodology, there is only one AURORA model run which is used to determine the displaceable incremental or avoided cost for each hour. These hourly avoided costs and the QF's supplied hourly generation profile are then used to determine monthly heavy load and light load pricing for the QF contract. Under this methodology, the incremental costs that Idaho Power would have incurred but for the QF generation is the basis for QF contract pricing. In both the current implementation of the IRP methodology and Idaho Power's proposed change to that methodology, QF generation is used to displace purchases. When purchases are displaced, the QF generation is valued at the cost of the displaced purchase. However, in the modified methodology, if the QF generation is not used to displace a purchase (a cost that Idaho Power would have incurred, but for the QF generation), it is used to displace one of Idaho Power's thermal resources (another cost that Idaho Power would have incurred but for the QF generation). Under the proposed methodology, the QF generation is **not** used to make market sales at AURORA-generated market clearing prices.

Q. Could you summarize the differences?

A. In summary, the main difference is that in Idaho Power's current implementation of the IRP methodology, the QF generation supports market sales which generate revenues that reduce Idaho Power's calculated power supply costs, essentially valuing the QF generation at AURORA's estimate of future market prices with customers taking all of the price risk. Under the proposed methodology, the QF generation does not support surplus sales, it is simply valued at the highest displaceable incremental cost Idaho Power is incurring during the hour. Thus, the proposed change focuses on determining the incremental costs that can be avoided by the addition of QF generation, and better aligns with the definition of avoided cost.

Under Idaho Power's current implementation of the IRP methodology, the QF receives a guaranteed contract price based on AURORA's estimation of future market prices. This eliminates the QF's risks with respect to future power market prices for the duration of the contract, and Idaho Power's customers have taken on the risk that the value of the generation received from the QF will differ from the QF's contract price. The Company's proposed change to determine the incremental cost during each hour is a much better estimation of the costs the utility is capable of avoiding by taking the QF generation, and comports with the federal requirements, without shifting all of the future market risk of the QF transaction onto Idaho Power's customers.

AVOIDED COST OF CAPACITY

Q. Please describe how the avoided cost of capacity is determined.

A. The methodology for determining avoided cost of capacity is the same as that used in Idaho Power's current implementation of the IRP methodology as described in Company witness Stokes' testimony.

Q. Does Idaho Power propose to use the same inputs in the determination of the capacity component of avoided cost?

A. No. Although the methodology for determining the capacity component of avoided cost is the same, Idaho Power proposes that the resource type used to determine this component of avoided cost be changed from a combined cycle combustion turbine ("CCCT") to a SCCT. Idaho Power's need for capacity is driven by summertime peak-hour loads, typically during the hours of 3:00 p.m. to

7:00 p.m. in the month of July. Because a SCCT is typically the lowest cost supply-side resource for this type of service, the fixed cost of a SCCT is a much more appropriate input to use for this purpose than those of a CCCT. Just as the current methodology uses the fixed costs of a CCCT taken directly from the Company's IRP analysis, the Company proposes that the fixed costs of a large frame industrial SCCT, taken directly from the Company's IRP analysis be utilized for determining the capacity component of avoided cost going forward.

As noted in Commission Staff comments on Idaho Power's Application for Determination Regarding its Firm Energy Sales Agreement with High Mesa Energy, LLC, Case No. IPC-E-11-26, Staff compared the capacity factors for SCCT and CCCT units included in the Company's 20-year resource plan in its 2009 IRP. Staff reported that based on modeling results from the IRP, the capacity factors of the SCCTs ranged from 0 to 14 percent and the capacity factor for Langley Gulch (a CCCT) ranged from 36 to 49 percent, with a 20-year average of 49 percent. This illustrates the fact that while the capital cost of a CCCT is higher, it will dispatch more often because of its higher efficiency (lower heat rate). The higher capital cost of a CCCT "buys" improved efficiency, which results in lower dispatch costs, and, subsequently, a higher annual capacity factor than a SCCT. In summary, a CCCT has higher fixed costs and lower variable costs, and a SCCT has lower fixed costs and higher variable costs.

Because the IRP methodology, as currently implemented and as proposed by Idaho Power, includes both capacity and energy components of avoided cost that are determined independently, Idaho Power believes that it is inappropriate to set the capacity component of avoided cost with the capital cost of a CCCT when its need for capacity can be served by a SCCT. As currently proposed, the energy component of avoided cost will be the same regardless of the resource type used to determine the capacity component of avoided cost. If a CCCT is used to set the avoided cost of capacity, customers will not receive the benefits associated with a CCCT's higher efficiency.

Q. Are you proposing to continue to use the **peak-hour** capacity factor calculation that is currently utilized?

A. Yes. Idaho Power proposes no changes to this approach, which is described by Company witness Stokes.

AURORA INPUTS/ASSUMPTIONS

Q. Are there any other assumptions or modeling details associated with the proposed changes to the IRP methodology that should be discussed?

A. Yes. Idaho Power's proposed change to the IRP methodology focuses on determining the incremental costs to an electric utility of electric energy which, but for the purchase from the QF, such utility would generate itself or purchase from another source. During many hours of the year, Idaho Power's highest displaceable incremental cost will be set by one of its thermal resources. And because a thermal plant's heat rate changes with load, the incremental costs also change with load. However, to simplify the analysis, Idaho Power proposes use of the following assumptions:

1. Each thermal unit is assigned one incremental cost, which will be based on full load operation, which applies all year long regardless of the loading level determined in the AURORA analysis;

2. The incremental cost for each thermal unit is updated each year based on the fuel forecasts used in the AURORA analysis; and

3. Once the highest displaceable incremental cost is identified for a given hour, any amount of displacement available from that resource (generator, longer-term firm purchase or market purchase) sets the incremental cost for that hour regardless of the volume actually available to be displaceable; e.g., if there are no purchases, and all thermal plants are either off or at

their minimums except for one Bridger unit which is at 10 MW above minimum and its incremental cost is $17/MWh, then the incremental cost for that hour is $17/MWh even if the "new" QF that the analysis is being run for is expected to produce 20 MW during that hour. This simplification may introduce some error, but it will always be in favor of the QF since Idaho Power begins with the highest incremental cost resource that is displaceable to set the avoided cost for any hour.

Q. Do you have an exhibit that illustrates these concepts?

A. Yes, these concepts are illustrated in Exhibit No. 7. There are six pages to this Exhibit.

Q. Will you please explain the purpose of each of the six pages in Exhibit No. 7?

A. Yes. Because the details of any avoided cost model at this level of detail can be quite complex and somewhat confusing, I have provided an example that illustrates a number of the details. At a high level, the first four pages of Exhibit No. 7 illustrate the type of data that will either be input to or output from the AURORA model. The last two pages of Exhibit No. 7 are the results of calculations used to determine the hourly incremental cost. This exhibit illustrates how a spreadsheet can be used to calculate an hourly incremental cost.

Page 1 of 6 illustrates the output from AURORA that is used by Idaho Power's proposed methodology to determine the hourly incremental cost. The hourly loading of each coal-fired and gas-fired unit is required, the hourly quantity of longer-term firm purchases and the AURORA-determined quantity of market purchases as well as the AURORA-determined market clearing price are also required. This information is largely used to determine which resource has room to be displaced.

Page 2 of 6 illustrates the thermal resource data used to set Idaho Power's minimum load levels and the heat rates used in the determination of each resource's annual incremental cost.

Page 3 of 6 illustrates fuel costs used in the determination of each resource's annual incremental cost.

Page 4 of 6 illustrates the variable O&M costs used in the determination of each resource's annual incremental cost, and it identifies the escalation rate used to escalate variable O&M costs.

Page 5 of 6 illustrates the results of calculations to determine the annual incremental costs that are used in each year to determine the hourly incremental cost. The calculation is as follows: incremental cost = [heat rate (MMBtu/MWh) x delivered fuel cost ($/MMBtu)] + variable O&M cost ($/MWh). The input data for heat rate is shown in

Btu/kWh; the units are converted to MMBtu/MWh as follows: MMBtu/MWh = (Btu/kWh) x (1 MMBtu/1,000,000 Btu) x (1,000 kWh/1 MWh).

Page 6 of 6 illustrates the result of calculations to determine the hourly incremental cost. First, the thermal resources on-line with displaceable capacity are identified by subtracting the hourly loading from the minimum loading - this occurs under the area labeled "Determine Displaceable Quantity (MW)." Next, under the area labeled "Determine Highest Displaceable Incremental Cost ($/MWh)" for each resource that has displaceable capacity, the incremental cost of that resource as determined on page 5 of 6 is listed. If the displaceable quantity is zero, then a zero is entered in this section. For longer-term firm purchases and market purchases, if the quantity of either is zero in an hour, then a zero is entered; if either is non-zero in an hour, then the market clearing price is entered. The hourly incremental cost is determined by taking the maximum of the values listed under the area labeled "Determine Highest Displaceable Incremental Cost ($/MWh)."

QF QUEUING PROCESS

Q. Does Idaho Power have any other proposed changes to the current implementation of the IRP methodology?

A. Yes. Idaho Power proposes that any QFs with signed contracts and any "queued" QFs be included in Idaho Power's resource portfolio for purposes of calculating future avoided costs because they can impact future avoided costs. For purposes of calculating avoided costs, Idaho Power proposes that upon its receipt of a written request from a QF for contract pricing, the QF is designated as "queued."

As stated earlier, Idaho Power's resource portfolio, for purposes of calculating a future avoided cost, can change whenever a QF project enters the queue if that QF is considered part of the resource portfolio. If "queued" QFs and QFs with signed contracts are considered to be part of the resource portfolio, then the calculated avoided cost of energy and capacity can change for each new QF as a result of the total amount of capacity and energy provided by all projects in Idaho Power's portfolio. These changes are not currently reflected in the avoided cost determination from the current methodologies – be it the SAR or the present implementation of the IRP-based methodology – which does not change with the incremental addition of more QF generation. Federal regulations allow for the individual and aggregate value of energy and capacity from QFs on the utility's system to be taken into account when determining avoided cost rates for purchases from QFs. 18 C.F.R. §

292.304. This must be taken into account if avoided cost is to be determined properly.

Q. Could you please explain?

A. Idaho Power's resource portfolio, for purposes of calculating its future avoided cost, can change whenever a new QF project enters the queue if that QF is considered to be part of the resource portfolio. For example, if all QFs with contracts are on-line, and there are no QFs in the queue, an analysis to determine the time series of Idaho Power's avoided costs for use in pricing a QF contract will produce a certain result. However, if there are five 20 MW QFs in the queue and they are likely to be built with the next few years, then Idaho Power is proposing they be included in subsequent analyses to determine Idaho Power's avoided costs for use in QF contract pricing because they could have a direct impact on calculations of Idaho Power's future avoided costs.

Q. What is the significance of including all QF projects, in the aggregate, into the avoided cost calculation?

A. The significance is that Idaho Power's avoided costs change over time. As new resources, QF contracts, or longer-term firm purchases are added to the resource portfolio, Idaho Power's avoided cost can change. The methodology used to calculate avoided costs needs to consider changes in the resource portfolio and the resulting impacts on avoided cost. If changes to the resource portfolio were limited to small changes, then impacts would be minimal. However, Idaho Power has seen large scale increases in the quantity of QF generation under contract in a very short period of time. Significant additions to Idaho Power's resource portfolio, such as the very large amount of QF generation that has been added to Idaho Power's system recently, can change Idaho Power's avoided costs, and the methodology to determine avoided cost must consider these changes.

Q. Do you have an exhibit that illustrates the difference in QF contract rates developed using Idaho Power's current implementation of the IRP methodology and the methodology Idaho Power is proposing?

A. Yes. Exhibit No. 8 provides an indication of these differences for several different QF projects - a 20 MW baseload project, a 20 MW canal drop project, a 20 MW fixed PV solar project, and a 22 MW wind project. These are the same four projects that Idaho Power used to illustrate its current approach for implementing the IRP methodology, which was presented to the parties of this case on December 15, 2011, in the Commission's hearing room. A copy of that presentation is attached to Company witness Stokes' testimony.

The proposed modifications to the IRP-based methodology produce a lower avoided cost of energy for each project. This is expected because the proposed modifications (which are based on identifying the incremental costs to the utility for energy or capacity which, but for the QF purchase, the utility would generate itself or purchase) produce an avoided cost that is based on the incremental cost avoided by displacing one of Idaho Power's thermal generating resources, or avoiding a market purchase. This is in contrast to the current implementation of the IRP methodology which uses the QF output to support market sales or displace purchases which results in a market-based valuation as opposed to a valuation based upon the definition of avoided cost.

The proposed modification to the type of resource used in the avoided cost of capacity calculation results in an avoided cost of capacity that is about 55 percent of that produced by using a CCCT. This is also expected because the capital costs of a SCCT are quite a bit less than the capital costs of a CCCT. The total investment costs for a SCCT and CCCT as identified in Idaho Power's 2011 IRP are $790/KW and $1,380/kW, respectively. Because Idaho Power's capacity needs are driven by summertime peak-load hours, and because a SCCT is an appropriate resource for this service, it reasonable to base the avoided cost of capacity on a SCCT.

Q. Do you have any concluding remarks?

A. Yes. Idaho Power respectfully requests that the Commission adopt the recommended changes to the IRP methodology as set forth above. These changes align the methodology to the definition of avoided cost from federal regulations, and they help ensure that customers remain indifferent as to whether the utility purchases energy from a QF, or whether it generates the energy itself, or purchases it from another source.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

BOKENKAMP, DI TESTIMONY

EXHIBIT NO. 7

Sample of AURORA output necessary to determine avoided costs

Year, Day & Hour			Thermal Unit Output and Purchse Quantity (MW)														Mkt Clearing Price ($/MWh)
Year	Day	Hour	Bridger 1	Bridger 2	Bridger 3	Bridger 4	Boardman	Valmy 1	Valmy 2	Danskin 1	Danskin 2	Danskin 3	Bennett Mtn	LG	LT Firm Purchases	Mkt Purchase	
2011	1	1	80	71	71	71	23	41	40	0	0	0	0	0	0	0	30
2011	1	2	71	71	71	71	23	41	40	0	0	0	0	0	50	0	30
2011	1	3	120	120	120	120	40	100	100	0	0	0	0	0	0	0	30
2011	1	4	120	120	120	120	40	100	100	160	45	45	160	250	0	0	40
2011	1	5	120	120	120	120	40	100	100	160	45	45	160	250	0	50	70
2011	1	6	120	120	120	120	40	100	100	160	45	45	160	250	50	50	45
2011	1	7	120	120	120	120	0	0	0	160	0	0	160	250	0	50	45
2011	1	8	120	120	0	0	0	0	0	0	0	0	0	0	0	50	30
2011	1	9	71	71	0	0	0	0	0	0	0	0	0	0	0	50	15
2011	1	10	71	71	0	0	0	0	0	0	0	0	0	0	0	0	15

Thermal Resource Data
Used in 2011 IRP Aurora Analysis

Unit	Nameplate Rating (MW)	Ownership Share (%)	Minimum Load (MW)	Min. Load IPCo Share (MW)	Full Load Heat Rate (Btu/kWh)
Bridger 1	540	33%	216	**71**	10,362
Bridger 2	540	33%	216	**72**	10,389
Bridger 3	540	33%	216	**72**	10,439
Bridger 4	540	33%	203.4	**68**	10,340
Boardman	508.5	10%	222.4	**22**	9,500
Valmy 1	254	50%	101.6	**51**	10,009
Valmy 2	267	50%	106.8	**53**	10,147
Danskin 1	170	100%	0	**0**	9,766
Danskin 2	49	100%	0	**0**	11,358
Danskin 3	49	100%	0	**0**	11,358
Bennett Mtn	170	100%	0	**0**	10,100
Langley Gulch	314	100%	204	**204**	6,997

PAGE 3 OF EXHIBIT NO. 7 CONTAINS CONFIDENTIAL INFORMATION

Variable O&M Cost Forecasts
Used in 2011 IRP Aurora Analysis
$/MWh

Variable O&M Esc. Rate 3.0%

	Bridger 1 ($/MWh)	Bridger 2 ($/MWh)	Bridger 3 ($/MWh)	Bridger 4 ($/MWh)	Boardman ($/MWh)	Valmy 1 ($/MWh)	Valmy 2 ($/MWh)	Danskin 1 ($/MWh)	Danskin 2 ($/MWh)	Danskin 3 ($/MWh)	Bennett Mountain ($/MWh)	Langley Gulch ($/MWh)
2011	0.57	0.57	0.57	0.57	0.81	1.55	1.55	3.03	2.88	2.88	3.03	1.33
2012	0.59	0.59	0.59	0.59	0.83	1.60	1.60	3.12	2.97	2.97	3.12	1.37
2013	0.60	0.60	0.60	0.60	0.86	1.64	1.64	3.21	3.06	3.06	3.21	1.41
2014	0.62	0.62	0.62	0.62	0.89	1.69	1.69	3.31	3.15	3.15	3.31	1.46
2015	0.64	0.64	0.64	0.64	0.91	1.74	1.74	3.41	3.24	3.24	3.41	1.50
2016	0.66	0.66	0.66	0.66	0.94	1.80	1.80	3.51	3.34	3.34	3.51	1.55
2017	0.68	0.68	0.68	0.68	0.97	1.85	1.85	3.62	3.44	3.44	3.62	1.59
2018	0.70	0.70	0.70	0.70	1.00	1.91	1.91	3.73	3.54	3.54	3.73	1.64
2019	0.72	0.72	0.72	0.72	1.03	1.96	1.96	3.84	3.65	3.65	3.84	1.69
2020	0.74	0.74	0.74	0.74	1.06	2.02	2.02	3.95	3.76	3.76	3.95	1.74
2021	0.77	0.77	0.77	0.77	1.09	2.08	2.08	4.07	3.87	3.87	4.07	1.79
2022	0.79	0.79	0.79	0.79	1.12	2.15	2.15	4.19	3.99	3.99	4.19	1.85
2023	0.81	0.81	0.81	0.81	1.15	2.21	2.21	4.32	4.11	4.11	4.32	1.90
2024	0.84	0.84	0.84	0.84	1.19	2.28	2.28	4.45	4.23	4.23	4.45	1.96
2025	0.86	0.86	0.86	0.86	1.23	2.34	2.34	4.58	4.36	4.36	4.58	2.02
2026	0.89	0.89	0.89	0.89	1.26	2.41	2.41	4.72	4.49	4.49	4.72	2.08
2027	0.91	0.91	0.91	0.91	1.30	2.49	2.49	4.86	4.62	4.62	4.86	2.14
2028	0.94	0.94	0.94	0.94	1.34	2.56	2.56	5.01	4.76	4.76	5.01	2.20
2029	0.97	0.97	0.97	0.97	1.38	2.64	2.64	5.16	4.90	4.90	5.16	2.27
2030	1.00	1.00	1.00	1.00	1.42	2.72	2.72	5.31	5.05	5.05	5.31	2.34
2031	1.03	1.03	1.03	1.03	1.46	2.80	2.80	5.47	5.20	5.20	5.47	2.41
2032	1.06	1.06	1.06	1.06	1.51	2.88	2.88	5.64	5.36	5.36	5.64	2.48
2033	1.09	1.09	1.09	1.09	1.55	2.97	2.97	5.81	5.52	5.52	5.81	2.55
2034	1.12	1.12	1.12	1.12	1.60	3.06	3.06	5.98	5.68	5.68	5.98	2.63
2035	1.16	1.16	1.16	1.16	1.65	3.15	3.15	6.16	5.85	5.85	6.16	2.71
2036	1.19	1.19	1.19	1.19	1.70	3.25	3.25	6.34	6.03	6.03	6.34	2.79

PAGE 5 OF EXHIBIT NO. 7 CONTAINS CONFIDENTIAL INFORMATION

PAGE 6 OF EXHIBIT NO. 7 CONTAINS CONFIDENTIAL INFORMATION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

BOKENKAMP, DI
TESTIMONY

EXHIBIT NO. 8

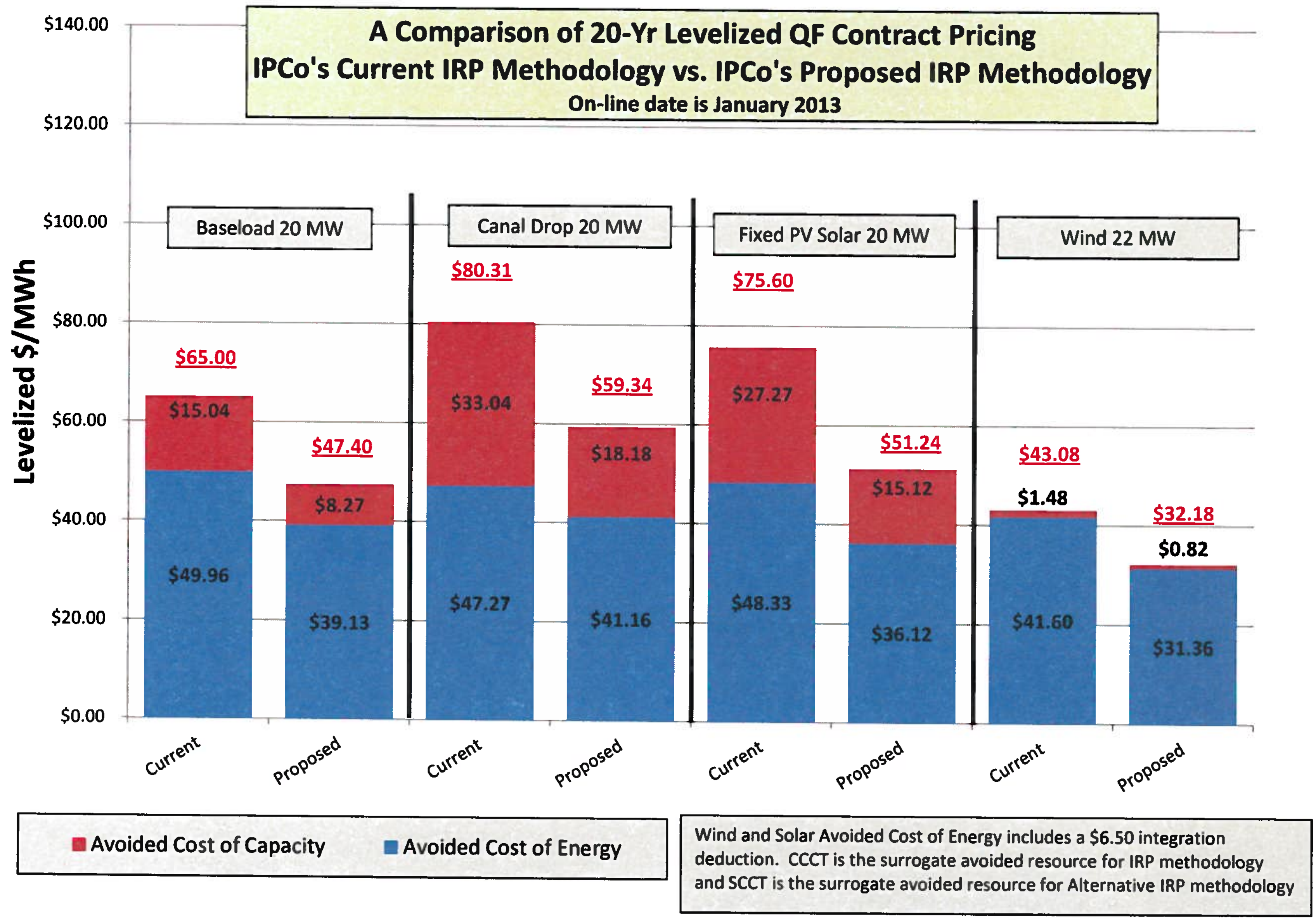

Exhibit No. 8
Case No. GNR-E-11-03
K. Bokenkamp, IPC
Page 1 of 1

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 31st day of January 2012 I served a true and correct copy of the DIRECT TESTIMONY OF KARL BOKENKAMP upon the following named parties by the method indicated below:

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I HEREBY CERTIFY that on the 31st day of January 2012 I served a true and correct copy of the CONFIDENTIAL PAGES OF EXHIBIT NO. 7 upon the following named parties by the method indicated below, and addressed to the following:

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