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UTILITIES COMMISSION

DONOVAN E. WALKER
Lead Counsel
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March 25, 2011

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. GNR-E-11-01
IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO DISAGGREGATION AND AN APPROPRIATE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP STRUCTURE FOR PURPA QUALIFYING FACILITIES

Dear Ms. Jewell:

Enclosed for filing in the above matter are nine (9) copies of the Direct Testimony of M. Mark Stokes. One copy of Mr. Stokes' testimony has been designated as the "Reporter's Copy." In addition, a disk containing a Word version of Mr. Stokes' Testimony is enclosed for the Reporter.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO DISAGGREGATION AND AN APPROPRIATE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP STRUCTURE FOR PURPA QUALIFYING FACILITIES.	)	CASE NO. GNR-E-11-01

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

M. MARK STOKES

Q. Please state your name and business address.

A. My name is M. Mark Stokes 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 Manager of Power Supply Planning.

Q. Please describe your educational background and work experience with Idaho Power.

A. I am a graduate of the University of Idaho with a Bachelor of Science Degree in Civil Engineering. I also hold a Masters Degree in Business Administration from Northwest Nazarene University and am a registered professional engineer in the state of Idaho.

I joined Idaho Power in 1991 as a member of the construction management team responsible for the construction of the Milner Hydroelectric Project. In 1992, I joined the Generation Engineering Department where I was responsible for dam safety and regulatory compliance for Idaho Power's 18 hydroelectric projects. In 1996, I began working with Idaho Power's Hydro Services Group, a new business initiative within the Power Production Department, where I was responsible for business development and marketing. In 1999, I returned to my previous position within the Power Production Department to administer Idaho Power's dam safety program.

In 2004, I accepted a position as the President of Ida-West Energy Company, a subsidiary of IDACORP. In this role, I was responsible for managing the overall operation of the Company as well as the operation and maintenance of nine hydroelectric projects with qualifying facility status. In 2006, I rejoined Idaho Power's Power Supply Business Unit as the Manager of Power Supply Planning. The Power Supply Planning Department is responsible for resource planning, load forecasting, and cogeneration and small power production contract management.

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

A. The purpose of my testimony is to provide direct testimony for Idaho Power in response to the Idaho Public Utilities Commission's ("IPUC" or "Commission") Order No. 32195 in this case, and Order No. 32176 in Case No. GNR-E-10-04.

In Order No. 32176, the Commission reduced the eligibility cap for published avoided cost rates from 10 average megawatts ("aMW") to 100 kilowatts ("kW") for wind and solar qualifying facilities ("QF"). Order No. 32176 states:

> The Commission solicits information and investigation of a published avoided cost rate eligibility cap structure that: (1) allows small wind and solar QFs to avail themselves of published rates for projects producing 10 aMW or less; and (2) prevents large QFs from disaggregating in order to obtain a published avoided cost rate that exceeds a utility's avoided cost.

Order No 32176, p. 11.

The Commission further clarified this request in Order No. 32195 stating:

> The Commission initiates this proceeding to investigate and determine in a finite time frame requirements by which wind and solar QFs can obtain a published avoided cost rate without allowing large QFs to obtain a rate that is not an accurate reflection of a utility's avoided cost for such purchases.

Order No. 32195, p. 1.

Q. Could you please summarize the recommendations of your testimony?

A. Yes. My testimony will discuss and conclude that:

1. The best method with which to address disaggregation issues is to extend and make permanent the published rate eligibility cap of 100 kW to all QF resource types, and to apply the Integrated Resource Plan ("IRP")-based avoided cost pricing methodology to all projects larger than 100 kW.

2. Should the Commission feel compelled to go back to a 10 megawatt ("MW") or a 10 aMW published rate eligibility cap, then the published rate should be developed using the IRP methodology and not the Surrogate Avoided Resource ("SAR") methodology. Idaho Power believes that the most effective way to assure that QFs do not obtain a rate that exceeds a utility's avoided cost is to require that avoided cost rates be determined using the Commission approved IRP-based methodology.

3. "Criteria" designed to separate QF projects by ownership interests and geographic proximity will not work and do not address the underlying problems of price, need, and an appropriately set avoided cost rate.

Q. Are these positions consistent with Idaho Power's submissions in GNR-E-10-04?

A. Yes. Idaho Power has stressed and reiterated the severe problems with the current SAR methodology and 10 aMW published rate eligibility in the Joint Petition of the three utilities, in Idaho Power's Comments, and in its Reply Comments in Case No. GNR-E-10-04, all of which are incorporated herein by this reference. Those problems are:

1. The continuing and unchecked requirement for the Company to acquire QF generation pursuant to published rates determined by the SAR

methodology and available to QFs sized at 10 aMW or less, with absolutely no regard for the Company's need for additional energy or capacity on its system, nor the availability of other lower cost resources.

2. Circumvention of the Company's required integrated resource planning process;

3. System reliability and other operational issues caused by a rapid and large scale increase in intermittent and unreliable generation sources; and

4. Most importantly, a dramatic increase in the price that Idaho Power's customers must pay for their energy needs as a direct result of the large quantities of additional QF generation at prices in excess of the Company's avoided cost, and beyond that which would otherwise be considered prudent.

Q. What does the Company mean by "beyond that which would otherwise be considered prudent"?

A. The addition of such large quantities of QF generation as those currently facing the Company, the majority of which are variable and intermittent in nature, is inconsistent with its least-cost, long-term, integrated resource planning process, and it creates operational and reliability issues. It is good utility practice to have diversity among generation resources, but too much of any single resource creates challenges. From an operational perspective, Idaho Power has reached or is nearing a saturation point with adding intermittent, variable generation to its resource portfolio.

Q. What is the significance of large amounts of intermittent and variable QF energy being inconsistent with the Company's least cost, long-term, integrated resource planning process?

A. As a public utility, Idaho Power is obligated to engage in a planning process that ensures it prudently acquires resources accounting for cost, risk, and environmental concerns. As I mentioned earlier, diversity in generation resources (e.g., thermal, hydro, renewable, etc.) is consistent with good utility planning practices. From an operational perspective (policy and legal arguments aside), it is neither good utility practice nor prudent for Idaho Power to be acquiring such large amounts of wind generation such as that which is currently scheduled to come onto its system. In fact, the preferred portfolio in Idaho Power's 2011 IRP, which is due to be filed in June 2011, does not include any new wind resources for at least the next ten years. This determination was reached prior to the addition of the large quantity of recent QF wind projects. The IRP Advisory Council and members of the public participating in the process have been in general agreement for some time that wind resources are not a good choice for Idaho Power for the following reasons: (1) it does little to meet Idaho Power's peak-hour needs, (2) its intermittent and variable nature, and (3) it creates a substantial amount of surplus energy during times when Idaho Power's customers' demand is low.

Q. What leads you to this conclusion?

A. The best way to explain this is with an example. Imagine if Idaho Power built a 600 to 800 MW power plant that was intermittent and variable in nature - consistent with the amount of proposed QF wind generation for Idaho Power's system and operating under similar constraints as those that are present with QF generation. Assume when that plant did generate, it was usually at times when the utility did not need the energy (e.g., light load hours and/or in shoulder months). These time periods also coincide with times when market prices, historically and forecast, are at their lowest and sometimes even negative. Further, assume that the plant placed additional strain on other Idaho Power resources because they would be relied upon to back-up the intermittency associated with the theoretical power plant, and the plant created overall system reliability issues. Now assume that the cost of this theoretical plant was locked in for 20 years at a price that exceeds market or other types of generation that the utility could otherwise acquire. Additionally, assume that such plant had certain times when it had to run and that the utility was required to take all of the plant's output to either serve load or sell it at market prices, typically at a loss. If Idaho Power sought approval of the Commission to build such a plant, it is unlikely that the Commission would approve it because it would not meet a basic prudency determination. The Company would have paid a higher price for such a plant than it could have otherwise acquired such generation, and, at times, would be incurring economic losses by paying a fixed price for the unneeded generation and selling it at a loss into a lower priced market - all of which would be passed through annually to the Company's customers in increased power supply expenses.

In the case of QF wind, the Company's present situation is very much the same as this theoretical power plant. The Company is being forced to take a type of generation it does not need to serve load at a price that is higher than that which it could otherwise acquire other available resources for.

Q. How is the discussion of the avoided cost pricing and methodology relevant to the Commission's direction in this docket, Case No. GNR-E-11-01, to "investigate and determine . . . requirements by which wind and solar QFs can obtain a published avoided cost rate without allowing large QFs to obtain a rate that is not an accurate reflection of a utility's avoided cost for such purchases"?

A. It is relevant because the underlying motivation for large QF projects to disaggregate is to obtain a higher avoided cost price as determined by the SAR methodology for projects less than 10 aMW - as opposed to negotiating a contract and setting an avoided cost price based upon the Commission-approved IRP methodology. The avoided cost as determined by the IRP methodology better reflects the utility's avoided cost and value of the energy and capacity being provided by the QF and theoretically displaced on the Company's system. QF developers readily admit that they disaggregate larger projects with the specific intent of obtaining a higher avoided cost rate calculated under the SAR methodology rather than follow the Commission's rules meant to set the avoided cost for these "larger" projects under the IRP methodology. *See* Case No. GNR-E-10-04, Petition for Reconsideration of the Northwest and Intermountain Power Producers Coalition, p. 13; January 27, 2011, Oral Argument, Tr. Vol. I, pp. 49-50.

As long as these two methodologies exist, and potentially result in different price calculations for the same project, and QF developers are given the option to select from the two different cost calculations, the problem of disaggregation will continue. It has been Idaho Power's experience, in the case of large-scale QF wind projects, that the SAR methodology generally produces a higher avoided cost rate than the IRP methodology. So long as the Company continues to be required to offer QF developers these two different pricing models, QF wind developers will always pick the model that will result in the higher rate for their project. This serves as an incentive for the QF developer to find a way to work around any disaggregation definition or rule established. If, on the other hand, the IRP methodology, which, as discussed, more accurately represents a utility's avoided costs, is used to establish the avoided cost rate, the QF developer will no longer have an economic incentive to disaggregate its large-scale wind project, and the development of a potential QF project would then be based on the avoided cost to the utility.

Additionally, beyond the immediate problem of disaggregation, the fact that the same project can have vastly different avoided cost price calculations, depending upon which avoided cost pricing methodology is applied, is strong evidence that the utility's avoided cost is not being determined properly by the more abstract SAR methodology, which increases costs for the Company's customers.

Q. Does Idaho Power receive many requests from "small" wind QFs to enter into power purchase agreements pursuant to PURPA?

A. No. In fact, nearly all of the wind QF projects that Idaho Power has contracted with, as well as those that approach Idaho Power seeking PURPA published rate contracts, are all large disaggregated projects whose individual pieces typically exceed 10, 20, and sometimes up to 30 MW of nameplate capacity. The ultimate common ownership suggests that if not disaggregated into smaller increments separated by one mile between them in order to qualify for published avoided cost rates, these projects would generally range in size from 40 MW to 150 MW in size.

For example, please refer to my Exhibit No. 2. This exhibit shows the last 17 wind QF projects with signed contracts that have been submitted to the Commission for review. All of these wind QF projects are disaggregated large projects, with the exception of the 5 MW Western Desert project. Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek are all Exergy projects located in the same locale (80 MW). Alpha, Bravo, Charlie, Delta, and Echo are all Shell Wind Energy projects previously known as Cotterel Mountain and located in the same locale (147.2 MW). Grouse Creek and Grouse Creek II have common ownership and are located in the same locale (42 MW). Murphy Energy, Murphy Mesa, and Murphy Wind have common ownership and are located in the same locale (60 MW). Rainbow Ranch and Rainbow West share common ownership and are located in the same locale (40 MW). This list could continue back through nearly all of the other Commission-approved QF power purchase agreements for Idaho Power, demonstrating the fact that Idaho Power actually receives very few, and almost no, truly "small" wind QF projects. Without the disaggregation of these wind QFs, they would all be required to use the IRP methodology to establish the avoided cost pricing in their contracts.

The Cotterel projects are amongst the best examples of how a wind QF is disaggregated and how the current PURPA system in Idaho can be manipulated to increase the costs borne by Idaho Power's customers and inflate the price a project developer receives for its sale of energy. The projects cannot deny and, in fact, make no attempt to even downplay the fact that they have purposefully disaggregated a large single project into 10 aMW increments in order to obtain a more favorable price. The project was initially proposed to Idaho Power as a single, large, 150 MW wind farm in the Company's 2009 wind request for proposals ("RFP"). The project was selected in that RFP process to initiate contract discussions. However, after many months of negotiations, an agreement was unable to be reached and negotiations were terminated. Idaho Power's RFP was also terminated for various reasons, one of which being the fact that the Company started to receive numerous requests for, and started placing large amounts of PURPA wind under contract, which it was required to purchase. The naming convention of Alpha, Bravo, Charlie, Delta, and Echo amplifies the image produced by viewing a map of the proposed projects that shows one continuous string of turbines, with just enough separation broken out between the pieces/parts to technically provide one mile of separation between "different" projects. Counsel for the projects has admitted the use of this practice "to obtain the published rate" in pleadings from the GNR-E-10-04 docket. *See* Petition for Reconsideration of the Northwest and Intermountain Power Producers Coalition, p. 13. Other disaggregated projects follow a very similar model of development.

Q. Does the Company have a recommendation regarding the Commission's potential use of some modified criteria as to QF ownership and geographical separation of projects that would allow "small" wind and solar QFs to avail themselves of published avoided cost rates for projects larger than 100 kW while preventing large QFs from disaggregating in order to obtain published avoided cost rates?

A. The Company does not support the sole use of some criteria regarding ownership and geographical separations as a solution to disaggregation. Adjusting the existing ownership or disaggregation criteria will not fix the underlying problem, which is the economic incentive created by the SAR-based pricing methodology, that motivates projects to disaggregate in order to obtain the higher avoided cost rate. The use of some criteria will not work because they do not address the underlying problems of price, need, and an appropriately set avoided cost rate. Even if the Commission were to develop rules that required independent ownership criteria and expanded the "one mile" location rule, I believe developers would become more creative in developing ownership and disaggregation schemes so long as they could avail themselves to the SAR-based avoided cost rate.

Q. Is your suggestion that QF developers would develop schemes to work around Commission-imposed ownership and disaggregation criteria merely speculation?

A. No. It has happened in Oregon. Oregon has rules that enable QF developers to receive the published avoided cost rates for projects up to 10 MW (nameplate capacity) or less if they are separated by at least five miles. The Company is aware of at least one instance in Oregon where a single developer was able to effectively disaggregate a single 65 MW wind project, covering an 8 to 10 mile footprint, into multiple QFs so that each project qualified for published avoided cost rates. Thus, while I understand the Commission wants to find a way to allow small QF wind and solar projects to have access to published avoided cost rates, I simply do not believe that adjusting the eligibility criteria will make that happen. QF developers with large-scale, utility grade projects will still find ways to work around the Commission's rules to access the published avoided cost rate if there is an economic advantage for them to do so.

Q. Did the Commission recently issue an Order in this docket delaying the requirement of the utilities to answer questions about the IRP methodology until a later phase of the proceedings.

A. Yes. However, there is a significant distinction that is relevant here. The validity of the IRP methodology is not in question; thus, the Commission's Order delaying discovery responses to a later phase of proceedings is appropriate. The IRP methodology is a Commission-approved, vetted, and authorized methodology that has been in place, in Idaho Power's case, for over 16 years as an accepted way to establish a utility's avoided cost. However, it is not a challenge to the validity of the IRP methodology to suggest, as Idaho Power is here, that application of that methodology is the appropriate solution to the problems and issues surrounding disaggregation of QF projects.

Q. Do you have a recommendation regarding the Commission's stated interest in an eligibility cap structure that "allows small wind and solar QFs to avail themselves of published rates for projects producing 10 aMW or less . . ."?

A. Yes. As an initial matter, however, I would like to point out that there is, to my knowledge, no legal or factual basis for setting the published avoided cost rate eligibility cap at anything above 100 kW, and at 10 MW or 10 aMW in particular. The Federal Energy Regulatory Commission rules implementing PURPA only require that a published avoided cost rate cap be set at 100 kW. That said, should the Commission determine that published rates should be available for projects larger than 100 kW; Idaho Power proposes that those published rates be set using the IRP methodology. This, in and of itself, solves the disaggregation problem by addressing the underlying problems of price and need inherent with the current SAR methodology. As I have already touched upon, the SAR methodology inflates the price above the Company's avoided cost and provides a very strong economic incentive for wind projects to disaggregate their larger projects to obtain that rate. Additionally, utilization of the IRP methodology to arrive at published avoided cost rates accomplishes the Commission's stated rationale and justification for raising the published rate eligibility above 100 kW - those being that of administrative ease and to level the playing field for unsophisticated "small" developers.

Q. Could you please explain how a published rate established by the IRP methodology would work?

A. Yes. Attached hereto as Exhibit No. 1, and incorporated herein by this reference, the Company has prepared five IRP methodology-based avoided cost calculations for various QF generation resource types as an example of this proposed published rate avoided cost calculation. The avoided cost rates were all calculated for 10 aMW generation resources consisting of: (1) fixed photovoltaic ("PV") solar; (2) canal drop hydro; (3) base load geothermal, biomass, anaerobic digesters; and co-generation; (4) spring-fed hydro; and (5) wind.

As can be seen on Exhibit No. 1, the resulting avoided cost price for each resource is: (1) fixed PV solar - $109.54; (2) canal drop hydro - $88.86; (3) base load geothermal, biomass, and anaerobic digesters - $86.66; (4) spring-fed hydro - $82.14; and (5) wind - $54.40 ($60.91 prior to the $6.50 wind integration cost). These calculations were performed utilizing the base case preferred resource portfolio and other required information from the Company's acknowledged 2009 IRP. The published IRP-based avoided cost rates would be updated every two years upon acknowledgement of the Company's IRP, and would remain in place until the acknowledgement of the next IRP, or until a material change in input assumptions warranted an update. A set schedule whereby the published avoided cost rate is known to be updated also works to provide the kind of certainty that developers advocate is so important for their development needs. This method actually provides more certainty than the current way in which the SAR-based published rates are updated when a new natural gas price forecast is issued by the Northwest Power and Conservation Council.

Also shown on Exhibit No. 1 are the two components of the IRP-based methodology's avoided cost calculation: (1) the avoided cost of capacity and (2) the avoided cost of energy. The avoided cost of energy is calculated using the AURORA electric market model, which is also used to make future resource decisions in the IRP. The avoided cost of capacity is calculated using the cost of a combined cycle combustion turbine ("CCCT") as a surrogate resource.

Q. Is this methodology any different than the currently approved IRP methodology for "larger" QF projects?

A. No. It is the same methodology. The only difference being that rather than calculating the avoided cost rate based upon the project's specific and unique generation profile (estimated hourly generation output for one year), the published IRP-based avoided cost rate is calculated using a representative generation profile for that resource type for Idaho Power's system/service territory.

Q. Do you have any other comments about Exhibit No. 1?

A. Yes. Idaho Power's currently approved 20-year levelized published avoided cost rate based upon the SAR methodology is currently $82.38 for a project coming on-line in 2011, as established by Commission Order No. 31025. It is a misconceived argument from the development community that the utilities' advocate for the IRP methodology because it always results in avoided cost rates that are below that calculated with the SAR methodology. The development community appears to simply assume that the avoided cost price for the IRP-based methodology is always lower, or more undesirable than the SAR's published rate. This is not true.

The IRP-based methodology, by considering a utility's need for power and incorporating the planned resource acquisitions from the utility's preferred resource portfolio in its acknowledged IRP, assigns a value to the power provided by the QF that is a much better measure of a utility's avoided cost than that which is calculated using the SAR methodology.

Q. Are there other reasons besides the beneficial effects upon the problems of disaggregation that are addressed by the utilization of the IRP methodology to set avoided cost rates?

A. Yes. The IRP methodology sets a more appropriate avoided cost by taking into consideration the *value* of the energy being provided by the QF and the *value* of the resources, in theory, being displaced. It calculates an individualized avoided cost price based upon the generation characteristics of the QF resource in relation to when the utility needs generation resources to meet its legal obligation to serve loads in its service territory. It correspondingly assigns a higher value, and price, to those resources that provide generation at peak hours, when the utility is most in need of additional generation, and assigns a lesser value, and price, to those resources that provide generation during light load hours, when the utility already has a surplus of generation resources and must sell excess generation from QFs, many times at a loss into a market where prices are lower than that which was paid for the QF energy.

The IRP methodology, in addition to bringing in some consideration as to the utility's need for the generation being provided, also aligns the acquisition of QF generation with the utility's required IRP least-cost planning process rather than frustrating that process as the current SAR-based methodology does. It makes much more logical sense, and aligns more with actual operations, to calculate an avoided cost rate using the AURORA model, which is also used for the IRP, than to create a fictional CCCT SAR that is actually not avoided by the addition of large amounts of intermittent and variable generation. In fact, there is the opposite effect. The addition of the large amounts of intermittent and variable generation that Idaho Power is facing with the presently existing and proposed QF wind projects actually increases the need for additional firm, load-following and load-shaping resources such as a CCCT.

Q. Why is it so important to Idaho Power that the Commission abandon the SAR methodology in favor of the IRP-based methodology?

A. Simply put, the continued use of the SAR-based methodology for published rates applicable to projects at 10 aMW or less results in application of avoided cost rates that are not reflective of the utility's avoided costs, are unjust, unreasonable, and inflate the power supply costs borne by the Company's customers. While the SAR-based methodology for published avoided cost rates may have been appropriate and reasonable in the past, the current application is no longer an accurate determination of a utility's avoided cost. The law requires that the Company's customers be held neutral, or indifferent, as to whether the power is purchased from a QF or otherwise acquired or generated by the utility. Customers are not being held neutral or indifferent with the current application of published avoided cost rates.

Q. Has the Company provided any examples of how customers are harmed by the current application of published avoided cost rates?

A. Yes. The Company provided information in the GNR-E-10-04 docket that just 678 MW of the newly executed QF wind contracts alone represented an obligation of over $3.9 billion over the 20-year term of the agreements. Idaho Power Comments, p. 7, GNR-E-10-04. A 614 MW portion of the newly contracted QF wind projects compared to market prices for the same power through 2020 results in an increased cost to customers of over $48 million on an annual basis. This is the equivalent of a 5 percent annual rate increase in the Company's Power Cost Adjustment ("PCA"). *Id.*, pp. 6-7, 18.

Q. Do you have any other information regarding the potential cost and harm to customers resulting from the current application of the published avoided cost rates?

A. Yes. Exhibit No. 2, attached hereto and incorporated herein by this reference, illustrates a comparison of the projected 20-year levelized cost of 17 of the most recently executed wind QF power purchase agreements, totaling 374 MW of nameplate capacity, that have been submitted to the Commission for its review - compared to projected market prices. Exhibit 2 shows that the Company's customers will pay the QF projects more than $25.00 per megawatt-hour over market prices for the same power. In total, for these 17 wind projects, customers will pay more than $540 million over and above forecast market prices for this energy over the 20-year term of the agreements.

The Company projects that it will pay just over $91 million for all PURPA cogeneration and small power production energy in 2011. This total amount increases to a total annual payment of just over $208 million in 2015. All of the newly executed wind QF contracts have on-line dates by the end of 2014. This is an increase in annual costs of more than $109 million, more than doubling current expenditures. This level of increase in power supply expenses leads to dramatic annual increases in customers' annual bills. For example, the above-referenced increase in power supply expenses attributable to new PURPA QFs translates directly into a $138,000 annual increase to the average Schedule 19, Large Power Service, customer's bill; a $97 annual increase to the average residential customer's bill; and annual increases ranging from just over $1 million to more than $3.6 million for the Company's Special Contract customers, its largest customers. This type of price impact to customers is unjust, unwarranted, and not in the public interest. In addition, the surplus energy produced by these QF projects does little to delay the need for additional capacity resources that will have to be built to serve the needs of Idaho Power's customers.

Q. Do you have any other recommendations for the Commission when considering how to deal with the problems of disaggregation of QF projects?

A. Yes. As referenced above, should the Commission determine that published rates should be available for projects larger than 100 kW, Idaho Power's recommendation is that those published rates be set using the IRP methodology. Additionally, the measurement of the published rate eligibility cap should no longer be measured on average MWs but instead should be based upon actual nameplate rating of the QF project. Nameplate rating had been the standard measurement to determine eligibility in the past, and the change in use to average MW has added to the problem of disaggregation by allowing much larger projects, in some cases up to 30 MW, to individually qualify for published rates. The use of nameplate MW rather than average MW is more likely to truly capture the smaller, more unsophisticated developers that the Commission intends to capture with published rates.

Q. Do you have any concluding remarks?

A. Idaho Power respectfully urges the Commission to make permanent the 100 kW published rate eligibility cap not only for wind and solar QF projects but for all QF projects and allow the avoided cost rates to be determined using the IRP methodology. This is a very straightforward way to quickly address the issue of disaggregation as well as other issues regarding QF contracts and avoided cost rates. Additionally, it has the added benefits of aligning with the Company's required integrated resource planning process, considering the Company's need for additional resources in the avoided cost rate calculation, and it more accurately reflects the Company's avoided cost.

Should the Commission determine that it wishes to make published rates available for wind and solar projects larger than 100 kW, the Company respectfully urges the Commission to only do so if those published rates are set pursuant to a resource specific IRP-based methodology for establishing the Company's avoided cost.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-01

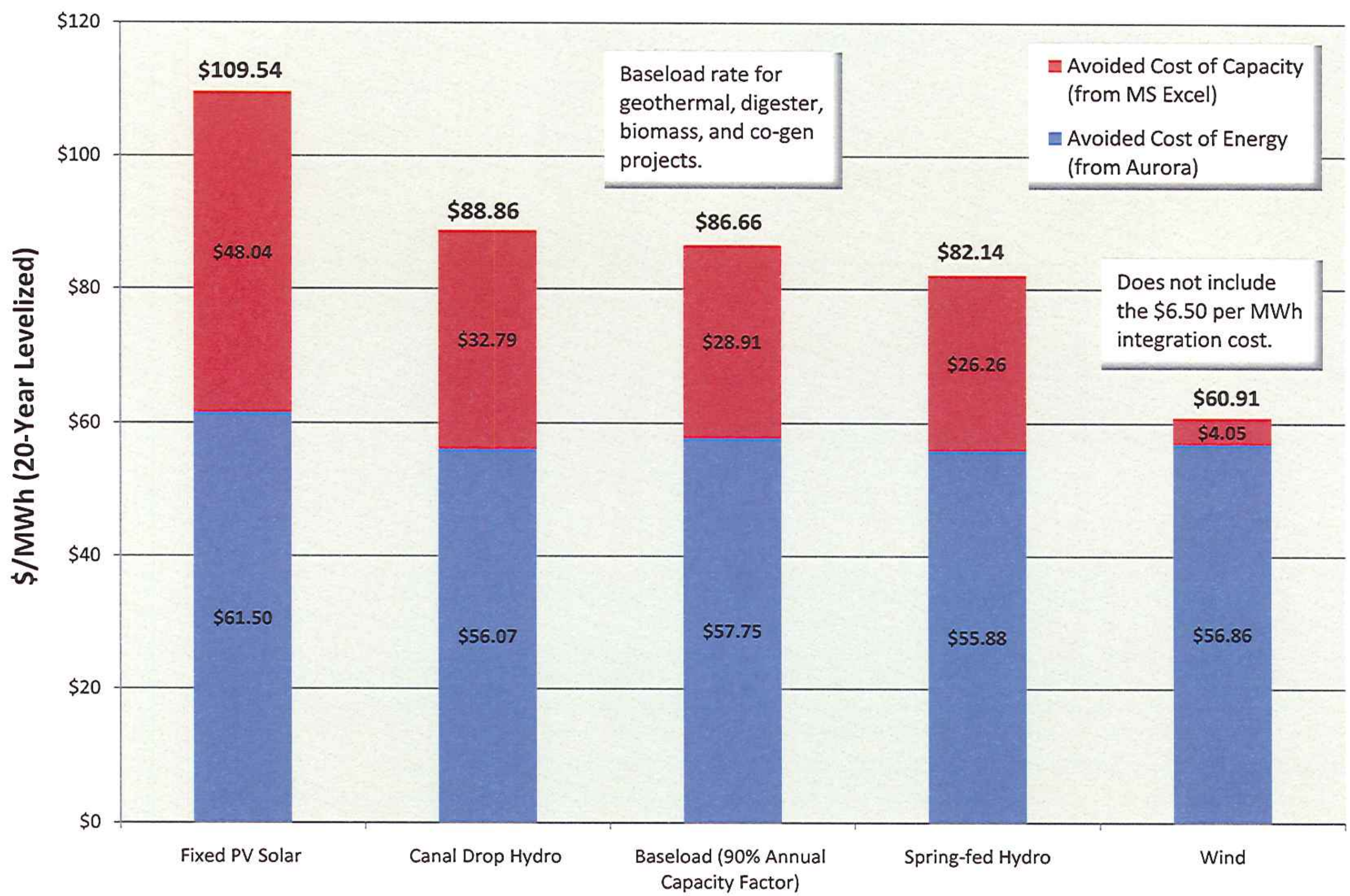
IDAHO POWER COMPANY

STOKES, DI
TESTIMONY

EXHIBIT NO. 1

Idaho Power IRP Methodology Avoided Cost Rates for PURPA

(10 aMW resources assumed to be on-line in 2012)



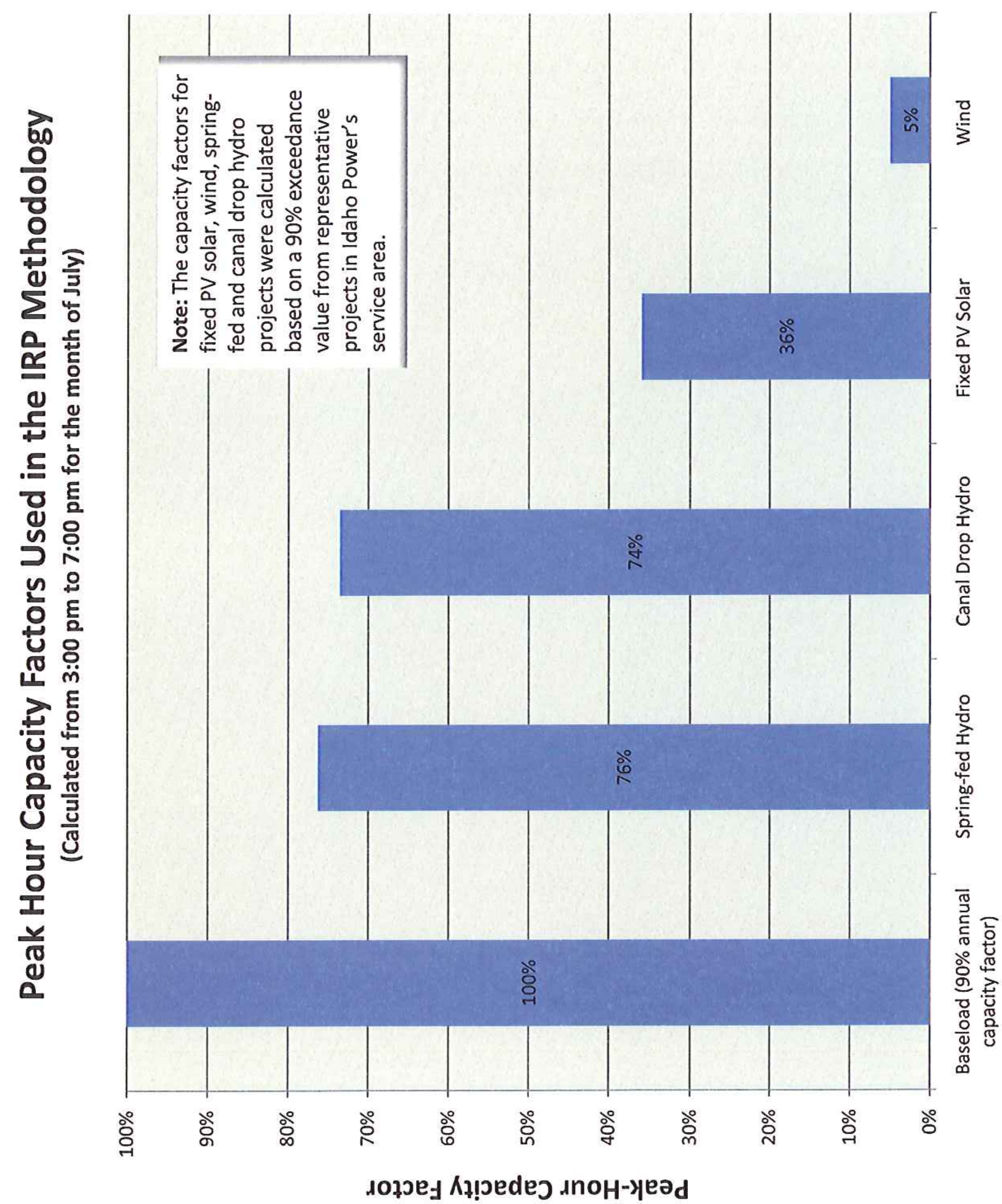


Exhibit No. 1
Case No. GNR-E-11-01
M. Stokes, IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-01

IDAHO POWER COMPANY

STOKES, DI
TESTIMONY

EXHIBIT NO. 2

Total Excess Resource Cost for Selected PURPA Contracts Prepared: February 16, 2011

20-Year Levelized Excess Cost ($/MWh) **$25.68**

Project Name	Nameplate Capacity MW	Annual Energy (kWh)	Annual Energy (MWh)	Annual Excess Cost ($)	Total Energy over 20 Years (MWh)	Excess Cost over 20 Years ($)
Cottonwood	20.0	61,572,804	61,573	$1,580,949	1,231,456	$31,618,987
Deep Creek	20.0	61,572,804	61,573	$1,580,949	1,231,456	$31,618,987
Rogerson Flats	20.0	61,572,804	61,573	$1,580,949	1,231,456	$31,618,987
Salmon Creek	20.0	61,572,804	61,573	$1,580,949	1,231,456	$31,618,987
Development Total	80.0	246,291,216	246,291	$6,323,797	4,925,824	$126,475,950
Alpha	29.9	76,593,869	76,594	$1,966,632	1,531,877	$39,332,634
Bravo	29.9	75,034,189	75,034	$1,926,585	1,500,684	$38,531,704
Charlie	27.6	75,197,240	75,197	$1,930,772	1,503,945	$38,615,435
Delta	29.9	77,189,349	77,189	$1,981,921	1,543,787	$39,638,426
Echo	29.9	73,722,292	73,722	$1,892,901	1,474,446	$37,858,016
Development Total	147.2	377,736,939	377,737	$9,698,811	7,554,739	$193,976,216
Grouse Creek	21.0	64,443,400	64,443	$1,654,655	1,288,868	$33,093,102
Grouse Creek II	21.0	64,443,400	64,443	$1,654,655	1,288,868	$33,093,102
Development Total	42.0	128,886,800	128,887	$3,309,310	2,577,736	$66,186,203
Murphy Energy	20.0	56,662,500	56,663	$1,454,872	1,133,250	$29,097,438
Murphy Mesa	20.0	56,662,500	56,663	$1,454,872	1,133,250	$29,097,438
Murphy Wind	20.0	56,662,500	56,663	$1,454,872	1,133,250	$29,097,438
Development Total	60.0	169,987,500	169,988	$4,364,616	3,399,750	$87,292,315
Rainbow Ranch	20.0	58,538,401	58,538	$1,503,038	1,170,768	$30,060,755
Rainbow West	20.0	58,538,701	58,539	$1,503,045	1,170,774	$30,060,909
Development Total	40.0	117,077,102	117,077	$3,006,083	2,341,542	$60,121,664
Western Desert	5.0	12,930,000	12,930	$331,992	258,600	$6,639,839
Development Total	5.0	12,930,000	12,930	$331,992	258,600	$6,639,839
GRAND TOTAL	374.2	1,052,909,557	1,052,910	$27,034,609	21,058,191	$540,692,188

Exhibit No. 2
Case No. GNR-E-11-01
M. Stokes, IPC

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 25th day of March 2011 I served a true and correct copy of the DIRECT TESTIMONY OF M. MARK STOKES upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Donald L. Howell, II Kristine A. Sasser Deputy Attorneys General Idaho Public Utilities Commission 472 West Washington P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email don.howell@puc.idaho.gov kris.sasser@puc.idaho.gov
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PacifiCorp d/b/a Rocky Mountain Power Daniel E. Solander J. Ted Weston Rocky Mountain Power 201 South Main Street, Suite 2300 Salt Lake City, Utah 84111	____ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email daniel.solander@pacificorp.com ted.weston@pacificorp.com
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