IDAHO POWER
An IDACORP Company

CHRISTA BEARRY
Legal Administrative Assistant
cbearry@idahopower.com

February 4, 2013

VIA ELECTRONIC FILING AND U.S. MAIL

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Re: Docket UM 1610
In the Matter of Public Utility Commission of Oregon Investigation into Qualifying Facility Contracting and Pricing

Dear Filing Center:

Enclosed for filing in Docket UM 1610 are an original and five (5) copies each of the Direct Testimony of Lisa A. Grow and M. Mark Stokes on behalf of Idaho Power Company. Copies of the testimonies have been served on all parties to this proceeding as indicated in the Certificate of Service.

Also enclosed are five (5) copies of a non-confidential disk containing workpapers used in the preparation of the above witnesses' respective testimonies. In addition, enclosed are (5) copies of a **confidential** disk containing confidential workpapers used to prepare Mr. Stokes' testimony. The confidential information will be sealed and sent via U.S. Mail.

If you have any questions, please do not hesitate to contact the undersigned.

Sincerely,

Christa Bearry

Christa Bearry
Legal Administrative Assistant

Enclosures

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UM 1610

IN THE MATTER OF PUBLIC UTILITY	)
COMMISSION OF OREGON	)
INVESTIGATION INTO QUALIFYING	)
FACILITY CONTRACTING AND PRICING	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

LISA A. GROW

February 4, 2013

Q. Please state your name and business address.

A. My name is Lisa A. Grow and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Vice President of Power Supply.

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

A. I graduated from the University of Idaho in 1987 with a Bachelor of Science degree in electrical engineering. I received an Executive Masters of Business Administration from Boise State University in 2008. I began my career at Idaho Power after graduating from the University of Idaho in 1987, and have held several engineering positions before moving into management in 2005. In 2005, I was named Vice President of Delivery Engineering and Operations. In 2009, I was appointed to my current position as Senior Vice President of Power Supply. My current responsibilities include overseeing the operation and maintenance of Idaho Power's generation fleet, power plant engineering and construction, environmental affairs, water management, power supply planning, and wholesale electricity and gas operations.

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

A. The purpose of my testimony is to present the Company's requests to modify the Public Utility Commission of Oregon's ("Commission") implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") as it is applied in the state of Oregon and more particularly to Idaho Power. I will provide an overview and summarize the Company's case and position.

I. INTRODUCTION

Q. Why did the Commission open this investigation?

A. The Commission opened this investigation in response to a request made by Idaho Power to change the methodology used to calculate Idaho Power's avoided cost prices available pursuant to standard contracts. To provide additional background and to better understand the process that lead to the Commission opening this investigation, it is important to first describe several other Idaho Power filings in early 2012.

Q. Please describe these Idaho Power filings.

A. The first filing was made on January 27, 2012, when Idaho Power filed an Application to Lower Standard Contract Eligibility Cap. This Application requested that the Commission reduce the eligibility cap applicable to standard contracts entered into by Idaho Power and qualified facilities ("QF") pursuant to PURPA. As was the case then (and continues to be the case today), any QF is eligible for a standard contract if its nameplate capacity is less than 10 megawatts ("MW"). Idaho Power requested that the Commission lower this eligibility cap to 100 kilowatts ("kW"), thus allowing most, if not all, QF contracts to be individually negotiated, and prices to be set based upon each project's specific and unique operating characteristics. This filing was docketed as UM 1575.

Concurrent with the Application, Idaho Power also made an advice filing to revise Idaho Power's Schedule 85, which is the Company's PURPA implementation schedule in Oregon, to reflect the requested lowering of the 10 MW eligibility cap. This tariff filing was docketed as UE 244.

As described in the Application to Lower Standard Contract Eligibility Cap, the Company was motivated by numerous factors to seek a reduction in the 10 MW eligibility cap. However, there was an added level of urgency to the Application when in the days leading up to the filing Idaho Power received requests for standard contracts from nine different QFs with a total nameplate capacity of 73 MW.

Q. How did the Commission resolve these filings?

A. The Commission addressed both filings at a public meeting on February 13, 2012. In Order No. 12-042, issued on February 14, 2012, the Commission rejected Idaho Power's Application and tariff filing and maintained the 10 MW eligibility cap for standard contracts. However, in response to the more immediate concern related to the nine new requests for standard contracts, the Commission temporarily suspended the requirement in Schedule 85 that the Company provide standard contracts to new QFs until the Company updated its avoided cost prices through the integrated resource planning process. As the Commission explained, "This decision effectively prohibits Idaho Power from entering into any standard contracts with QFs for an approximate 60 day period. During this time, QFs are eligible to negotiate and enter into non-standard contracts with Idaho Power."[1]

Q. What happened next?

A. On March 15, 2012, Idaho Power made three additional filings: (1) Idaho Power updated its avoided cost prices following the acknowledgment of the Company's 2011 IRP; (2) Idaho Power filed an Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices; and (3) Idaho Power filed a Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities.

Q. Please describe the filing to update Idaho Power's avoided cost prices.

A. This filing was made pursuant to OAR 860-029-0040(4)(a), which requires Idaho Power to file updated avoided cost prices for standard contracts within 30 days of the

[1] Order No. 12-042 at 2.

Commission acknowledgement of the Company's most recent Integrated Resource Plan ("IRP"), which occurred on February 14, 2012. This filing was docketed as UM 1593.

Initially, the Company's updated prices were made using the Commission-approved methodology set forth in Order No. 05-584, which authorized Idaho Power to use the Idaho Surrogate Avoided Resource ("SAR") methodology. However, in response to concerns regarding the accuracy of the Idaho SAR methodology, Commission Staff ("Staff") contacted Idaho Power and suggested that the Company make an alternative avoided cost filing using the same method used by Pacific Power and Portland General Electric Company to calculate prices for their standard contracts during periods of resource sufficiency. Staff explained that this methodology accounts for the resource sufficient or deficient position of the utility, and pointed out that under that methodology, Idaho Power is currently resource sufficient and will be until 2016 when, as reflected in the recently acknowledged 2011 IRP, the Boardman to Hemingway transmission line is scheduled to come on-line. Staff referred to this methodology as the "Oregon Method."

In response to Staff's request, on April 10, 2012, Idaho Power made another filing in UM 1593 that calculated Idaho Power's avoided cost prices using the Oregon Method. Because the Company is resource sufficient until 2016, the avoided cost prices were determined based on market prices through 2015. For 2016 and after, when the Company is resource deficient, the avoided cost price was calculated using the Oregon Method SAR methodology.

Q. Please describe the Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices and the Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities.

A. As discussed above, these filings were both made on March 15, 2012, concurrent with the compliance filing updating the Company's avoided cost pricing. The Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices requested Commission authorization for Idaho Power to revise the Company's method of determining its avoided cost prices for standard contracts. The Company proposed abandoning the use of a SAR-based methodology in favor of the more accurate and comprehensive IRP-based methodology. Accompanying Idaho Power's application was the testimony of M. Mark Stokes, which described in detail the current status of QF development on Idaho Power's system. Mr. Stokes' testimony also described the serious deficiencies in a SAR-based methodology and provided explanations of how those deficiencies are addressed using an IRP-based methodology.

The Motion for a Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities requested that the Commission extend the Order No. 12-042 temporary suspension of Idaho Power's obligation to enter into standard contracts pending the outcome of the investigation requested by the Company in its Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices.

Q. How did the Commission resolve these filings?

A. The Commission addressed all three filings at its April 24, 2012, public meeting and issued Order No. 12-146 the next day. With this Order, the Commission approved Idaho Power's avoided cost prices calculated using the Oregon Method. The Commission also lifted the stay that was issued as part of Order No. 12-042 because the Company's avoided cost prices had been updated.

In response to Idaho Power's Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices, the Commission "ordered that a generic docket be opened to investigate issues related to electric utilities' purchases from QFs, generally. Idaho Power's requested method for calculating avoided-cost prices will be an issue in the new docket."[2] This docket is the generic investigation opened by the Commission in Order No. 12-146.

The Commission also denied Idaho Power's request for a stay of its obligation to enter into standard contracts and "clarified that any contracts entered into between Idaho Power and QFs at this time will be governed by the avoided-cost prices established in docket UM 1593 (calculated using the "Oregon method"). The prices in these contracts will not change, even if the investigation ultimately leads to adoption of a new methodology and new avoided-cost prices."[3]

Q. What has the Commission stated with regard to the purpose and/or scope of the present proceeding?

A. As described in Order No. 12-146, the purpose of this proceeding is to generically investigate all issues related to purchases by electric utilities from QFs. Because the Commission did not limit or otherwise provide specific guidance regarding the scope or issues that could be addressed in this docket, the parties have worked collaboratively to develop an issues list, which was approved by Administrative Law Judge Michael Grant on October 25, 2012. The issues identified were divided into seven general sections:

1. Avoided Cost Price Calculation;
2. Renewable Avoided Cost Price Calculation;
3. Schedule for Avoided Cost Price Updates;
4. Price Adjustments for Specific QF Characteristics;

[2] Order No. 12-146 at 1.

[3] Order No. 12-146 at 2.

5. Eligibility Issues;

6. Contracting Issues; and

7. Interconnection Issues.

After identifying the issues, the parties then worked together to develop a procedural schedule for this docket. As part of that schedule, the parties agreed to bifurcate the docket into two phases. Phase 1 will address Issues 1 through 5, along with two items from Issue 6—the first relating to legally enforceable obligations and the second relating to contract duration.

Q. Did Idaho Power participate in a similar QF proceeding in front of the Idaho Public Utilities Commission ("Idaho Commission")?

A. Yes. The Idaho Commission recently issued a final order, Order No. 32697 in Case No. GNR-E-11-03, in a multi-year, multi-phase, comprehensive investigation into QF and PURPA implementation in the state of Idaho. The final order was issued December 18, 2012, and, as of the date of filing this testimony, the Idaho Commission is working through the process of reconsideration and clarification of that final order.

Q. Could you please summarize the case that was before the Idaho Commission?

A. Yes. The Idaho Commission conducted its investigation through three phases addressing: first, issues related to disaggregation of larger projects into smaller increments in order to qualify for standard avoided cost rates; moving to a full examination of avoided cost rate methodologies; contracting practices, terms, and conditions; curtailment; environmental attribute ownership; and several other issues related to the implementation of PURPA in the state of Idaho.

The Idaho investigation originated with a November 5, 2010, Joint Petition to Address Avoided Cost Issues and Joint Motion to Adjust the Published Avoided Cost Rate Eligibility Cap ("Joint Petition") filed by Idaho Power, Avista Corporation, and

PacifiCorp d/b/a Rocky Mountain Power requesting that the Idaho Commission initiate an investigation to address various avoided cost issues related to the Idaho Commission's implementation of PURPA. In 2010, QF interest in published rate contracts in Idaho increased dramatically. A large majority of the QFs seeking published rate PURPA contracts were large-scale wind projects that developers were disaggregating into 10 average megawatt ("aMW") projects in order to qualify for published avoided cost rates. The electric utilities regulated by the Idaho Commission—Idaho Power, Avista Corporation, and PacifiCorp d/b/a Rocky Mountain Power (collectively, the "Utilities")—filed a Joint Petition on November 5, 2010, requesting that the Idaho Commission initiate an investigation to address various avoided cost issues related to the Idaho Commission's implementation of PURPA including the disaggregation practice as well the avoided cost methodologies used to determine the Utilities' avoided costs. At the same time, the Utilities moved for an immediate reduction in the published avoided cost rate eligibility cap, from 10 aMW down to 100 kW.

On December 3, 2010, the Commission issued Order No. 32131, in which it declined to reduce the eligibility cap immediately, but instead gave notice that it would investigate issues related to avoided cost pricing, starting with the issue of disaggregation (Phase I), and that its final decision whether to reduce the eligibility cap would become effective on December 14, 2010. *Id.* at 5-6, 9.

On February 17, 2011, after soliciting comments from interested parties and hearing oral argument, the Idaho Commission ordered a temporary reduction in the published avoided cost rate eligibility cap, from 10 aMW down to 100 kW, for wind and solar projects only. Order No. 32176 at 1-2. The temporary cap reduction became effective as of December 14, 2010, and was to remain in place pending the outcome of Phase II of the Idaho Commission's investigation. Shortly thereafter, on

February 25, the Commission initiated Phase II of its investigation into disaggregation and PURPA published avoided cost rates. Order No. 32195. Phase II concluded on June 8, 2011, with the Idaho Commission's final order maintaining the 100 kW eligibility cap for wind and solar projects. Order No. 32262, Case No. GNR-E-11-01.

On September 1, 2011, the Idaho Commission commenced Phase III—an investigation of both the SAR methodology and the IRP methodology used by the Utilities to calculate avoided cost rates in order to ensure that avoided cost rates are just and reasonable. Order No. 32352, Case No. GNR-E-11-03. The parties submitted testimony, and a three-day technical hearing was held in August 2012. The Idaho Commission issued final Order No. 32697 on December 18, 2012, and the Idaho Commission is currently considering petitions to reconsider and/or to clarify its final order.

Q. Could you please summarize the Idaho Commission's final Order No. 32697 with regard to the avoided cost pricing methodologies?

A. Yes. The Idaho Commission ordered the continued use of a SAR-based avoided cost methodology for all QF projects below the published rate eligibility cap. The Idaho Commission retained the 100 kW published rate eligibility cap for wind and solar QFs, as well as a 10 aMW cap for all other resource types. The Idaho Commission ordered the differentiation of published, or standard, rates based upon each QF's resource type using the different resources' capacity factor. The Idaho Commission also directed the use of the natural gas forecast published by the U.S. Energy Information Administration ("EIA"), and directed annual updates to the published, or standard, avoided cost rates.

The Idaho Commission ordered that the IRP methodology continue to be utilized to establish the starting point for calculating a negotiated avoided cost rate for all QF projects that are over the published rate eligibility cap (100 kW for wind and solar and 10 aMW for all other resource types). The Idaho Commission also approved modifications to the IRP methodology proposed by Idaho Power that bases the avoided cost calculation upon the QF's generation profile and the utility's highest displaceable incremental cost on an hourly basis. The Idaho Commission found that the modifications to the IRP methodology properly focused the determination of avoided costs on incremental costs and not upon the value of potential market sales, that it resulted in a more accurate avoided cost, and that it comports with the definition of avoided cost contained in Federal Energy Regulatory Commission ("FERC") regulations.

Idaho Power requests in this proceeding that the Oregon Commission allow similar revisions to Idaho Power's Oregon Method for calculating standard rates, the standard rate eligibility cap, and the IRP methodology.

II. CASE SUMMARY

Q. Could you please provide an overview of Idaho Power's case and summarize the testimony of the Company's witnesses?

A. Yes. In addition to my own testimony, the Company submits the Direct Testimony of M. Mark Stokes, Director of Water and Resource Planning. Mr. Stokes describes the current status of PURPA QF projects on Idaho Power's system, as well as the current implementation of both the Oregon Method SAR avoided cost methodology for standard rates and contracts and the IRP avoided cost methodology for negotiated rates and contracts. He addresses issues related to risk and harm to Idaho Power customers imposed by the current implementation of PURPA. He also addresses the Company's position on the several issues identified for Phase 1 of this docket in the Administrative Law Judge's October 25, 2012, and December 21, 2012, rulings.

Q. What are Idaho Power's major concerns in this case?

A. Idaho Power is deeply concerned about the negative economic impact on customers caused by the implementation of PURPA and its requirements, as well as the detrimental effect that the accumulated and continuing addition of PURPA QF generation is having on Idaho Power's system and operations. The economic ramifications are extremely harmful to customers. Idaho Power is very concerned that the avoided cost methodologies approved by the Commission have become disconnected from federal requirements and the definition of avoided cost. This has resulted in an environment that has fostered rapid and uncontrolled development of QF generation projects that are causing substantial harm to Idaho Power customers by greatly inflating power supply costs while at the same time degrading the reliability of the system.

Idaho Power's main concern is that the Company is obligated to take a very large amount of generation that it does not need and is not valuable to its operations, while at the same time paying more for it than other generation or market purchases that are available to serve load. The Company is also very concerned about the very large and dramatic increase in power supply costs that must be borne by customers because of the mandatory QF purchases that cost more than the Company's own generation or alternative purchases. Idaho Power desires that the requirements of PURPA continue to be met, but also wants to ensure that Idaho Power's requirements of providing safe, reliable, and low cost power to its customers is not undermined in doing so.

Q. What does Idaho Power see as problems with the current implementation of PURPA?

A. Several things: (1) the continuing and unchecked requirement for the Company to acquire QF generation, pursuant to avoided cost rates, with little regard for the

Company's need for additional generation on its system, nor the availability of other lower cost resources, and in a manner inconsistent with the federal definition of avoided cost; (2) circumvention of the Company's required IRP planning process and a continuing requirement to acquire generation outside of that established process that inflates customers' power supply costs; (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.

These items are discussed in more detail in the direct testimony of Mr. Stokes.

Q. Do you have an exhibit that depicts the level of QF development on Idaho Power's system?

A. Yes. Attached as Exhibit 101 are two graphs, as well as a spreadsheet, showing the number of MW of QF generation that currently operates on Idaho Power's system, as well all QFs that are currently under contract to deliver energy to Idaho Power. Additionally these graphs show the additional QF projects that are presently seeking contracts with Idaho Power, and those projects that are engaged in legal proceedings seeking to obtain power sales agreements with Idaho Power.

Q. Could you further describe Exhibit 101?

A. Yes. There are two graphical representations that show the same information for two different points in time. The first shows the levels of QF development, broken down by resource type, as of December 2010. This date is significant because it coincides with the state of Idaho Power's system when the Idaho PURPA investigation was initiated with the Joint Petition of the Idaho Utilities as described above. The graph generally shows the explosive and massive growth in QF development on Idaho Power's system in recent years, starting in approximately 2003 with the arrival of Idaho Power's first wind QF. Prior to 2003-2004, and since PURPA was first enacted in 1978, Idaho Power had numerous PURPA QF projects operating on its system and under contract. However, most of these QFs were small projects, and many of them were agricultural based small hydro electric generation facilities. The Company carried a steady fleet of less than 200 cumulative MW of PURPA generation for approximately the first 20 years of the existence of PURPA. However, as the graph shows, starting in the 2003 to 2004 time period—and continuing to today—the Company has seen a massive spike in the number of projects and an even larger increase in the number of MW that it has been required to take as QF generation.

In December of 2010, the Company had just under 1,000 MW of QF generation under contract, nearly 700 MW of which was comprised of wind generation. Including the additional QF projects seeking contracts with the Company, the total skyrockets to over 1,800 MW. Idaho Power's record peak load is approximately 3,200 MW, and its minimum (or off-peak) load for the entire 24,000 square mile service territory is around 1,100 MW.

The second graph represents the same information, but for the time period as of December 2012. After the passage of more than two years and numerous state and federal cases litigating various issues related to the implementation of PURPA requirements, the graph is somewhat smaller in magnitude, but still retains the same alarming growth and large numbers. As of December 2012, the total MW of PURPA under contract with Idaho Power is just over 800 MW. What is significant about this graph is that there is still approximately 400 additional MW of new projects either seeking contracts or in dispute wanting to come onto Idaho Power's system. The number of projects seeking to contract with Idaho Power far exceeds the total amount of PURPA generation on most Northwest utilities' entire systems. The total number of QF projects both under contract and seeking contracts remains quite large at over 1,200 MW.

Q. How does the large increase in PURPA generation affect Idaho Power's customers?

A. Customers pay 100 percent of PURPA power supply costs in the annual Power Cost Adjustment (PCA) for Idaho customers and through the Annual Power Cost Update (APCU) and Power Cost Adjustment Mechanism (PCAM) for Oregon customers. PURPA power supply costs, while never insignificant, were relatively small and stable from 1982, when the first QF projects were connected to the Company's system, until about 2003. Since 2004, PURPA expense has grown dramatically, and customers will see very significant annual rate increases out to 2026 based upon the current QF projects that are currently generating, and those that have approved power sales agreements to date. As shown in more detail in the testimony of Mr. Stokes, annual PURPA power supply expenses in 2004 were approximately $40 million. It took more than 20 years of accumulation of annual PURPA expense to amount to the 2004 one-year magnitude of cost. Just five years later, by 2009, that amount grew by 50 percent to approximately $60 million. Just another three years after that, in 2012, that $60 million nearly doubled to $117 million of annual PURPA power supply costs. That number increases to $140 million by 2014, and by 2026, will be $146 million <u>annually</u>, an approximate 365 percent increase in costs from 2004. This will result in dramatic annual rate increases for all of Idaho Power's customers.

Q. Please summarize the Company's requested relief in this case?

A. The Company has conducted a comprehensive examination of the process by which the Commission implements the requirements of PURPA and PURPA's corresponding FERC regulations. Idaho Power's testimony summarizes the current procedures and methodologies that are in place, and requests changes in several areas. The Company demonstrates through testimony how its proposed changes both comply with the federal requirements of PURPA, and address severe problems with the current implementation of PURPA. If left unaddressed, the current problems associated with the implementation of PURPA will continue to unnecessarily inflate the power supply costs of its customers and to degrade the reliability of Idaho Power's system.

To address the current and potential economic harm to Idaho Power customers as a result of continuing to add large amounts of unneeded generation to its system at a high cost, Idaho Power requests first, that the current Oregon Method used to determine standard avoided cost rates for QF projects with less than 10 MW of nameplate capacity be adjusted to differentiate rates based upon the type of generation resource that is proposed, using that resource's capacity factor. Idaho Power also proposes that standard rates be updated annually with the natural gas forecast published by the EIA.

Idaho Power also requests that the Commission continue to authorize the use of the same IRP methodology approved by the Idaho Commission for QFs over the standard rate eligibility cap to be used as the starting point for QF contract negotiations. The IRP methodology has recently been modified in Idaho in order to better estimate Idaho Power's avoided cost, and to better align the methodology with the definition of avoided cost from federal regulations.

Additionally, Idaho Power requests that the Commission continue to require the use of standard avoided cost rates and contracts for QF projects with a nameplate capacity of 10 MW or less for all generation types except for wind and solar. For wind and solar QF projects, Idaho Power proposes that standard rates and contracts be required only for those projects that have a nameplate capacity of 100 kW or less, consistent with FERC regulations, and with the Company's Idaho jurisdiction. This change in standard rate eligibility for wind and solar would require all wind and solar QFs over 100 kW of nameplate capacity to have rates based upon the IRP methodology, which is a better estimate of Idaho Power's avoided cost, and more closely aligns the methodology with the definition of avoided cost from federal law.

These requested changes to the avoided cost pricing methodology are steps in the right direction to more closely estimate Idaho Power's avoided cost—the incremental cost that the utility would incur, either by generating the power itself or purchasing it from another source, but for the purchase from the QF. It is also a step in the right direction to better ensure that Idaho Power customers remain neutral as to whether the power was purchased from a QF or otherwise acquired by the utility, as is required by federal law. It also starts to bring aspects of utility need into the determination of avoided cost prices.

Idaho Power also proposes that the Commission continue to authorize contracts for up to 20 years. However, to mitigate and reduce the risk born entirely by Idaho Power customers associated with long-term power purchase commitments at a fixed price or rate, Idaho Power proposes that the currently authorized 15-year fixed price portion of the contract be reduced to 10 years. Additionally, Idaho Power proposes that the Commission not allow a levelized contract price over the term of the contract.

Lastly, Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA

QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PURPA contract itself, regardless of whether the utility signs. Further, if the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established.

Q. Please detail the specific approval the Company is requesting from the Commission.

A. The Company requests specific Commission approval of the following:

1. Standard Rates and Contracts. Idaho Power proposes that the current Oregon SAR Method used to determine standard avoided cost rates for QF projects with less than 10 MW of nameplate capacity be adjusted to differentiate rates based upon the type of generation resource that is proposed, using that resource's summertime, peak-hour capacity factor. Additionally, Idaho Power proposes that standard rates be updated annually with the natural gas forecast published by the EIA;

2. Negotiated Rates and Contracts. Idaho Power's current Oregon Schedule 85 authorizes the use of the same IRP modeling methodology approved by the Idaho Commission for QFs over 10 MW of nameplate capacity to be used as the starting point for negotiations. Idaho Power proposes no changes to this authorization. However, the Idaho Public Utilities Commission has approved modifications to the Company's IRP methodology that Idaho Power will discuss in testimony;

3. Standard Rate Eligibility Cap. Idaho Power proposes that the Commission continue to require the use of standard avoided cost rates and contracts for QF projects with a nameplate capacity of 10 MW or less for all generation types except for wind and solar. For wind and solar QF projects, Idaho Power proposes

that standard rates and contracts be required only for those projects that have a nameplate capacity of 100 kW or less, consistent FERC regulations, and with the Company's Idaho jurisdiction;

4. Wind Integration Charge. Idaho Power proposes to implement a wind integration charge for any wind QF contracting with the Company;

5. Contract Term. Idaho Power proposes that the Commission continue to authorize contracts for up to 20 years. However, Idaho Power proposes that the currently authorized 15-year fixed price portion of the contract be reduced to 10 years. Additionally, Idaho Power proposes that the Commission not allow a levelized contract price over the term of the contract;

6. Environmental Attributes/Renewable Energy Credits ("RECs"). Idaho Power proposes that the Commission determine that Idaho Power owns all RECs associated with the QF energy that it must purchase from PURPA QF projects; and

7. Legally Enforceable Obligation. Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PURPA contract itself, regardless of whether the utility signs. Further, if the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established.

The Company believes that these determinations can reasonably be made based upon the full and detailed testimony provided by the Company in this case.

Q. Is it your opinion that granting the requested relief proposed by the Company is in the public interest?

A. Yes. The great advantages that Idaho Power customers, its service territory, and its region enjoy from consistently having some of the lowest electricity prices in the nation are being eroded by a flood of QF generation that we all are paying too much for. Idaho Power is forced to purchase this power with no regard to whether it is needed on its system, with no regard to whether it is called for in the Company's IRP process, and with no regard to whether there are other lower cost alternatives for its customers. Additionally, the Company is forced to deal with the difficult tasks and problems associated with integrating large amounts of intermittent and variable renewable generation into its system, once again with customers paying the resulting price. In most instances, customers do not even get the "benefits" derived from the renewable attributes of that generation in the form of RECs, nor is the Company even able to "claim" or get credit for the existence of that renewable energy on its system.

In this proceeding we have the unique opportunity to re-examine the appropriateness of the methodologies used to set avoided cost, and to re-examine the way that the state of Oregon implements the federal requirements of PURPA. Idaho Power is deeply affected by these determinations, as are its customers, and has proposed reasoned and rational solutions to both ensure that the requirements of PURPA continue to be met, but also that Idaho Power's requirements of providing safe, reliable, and low cost power to its customers is not undermined in doing so. The Company's proposals are in the public interest, comply with federal requirements, and the Company respectfully asks the Commission to implement the same.

Q. Does this conclude your testimony?

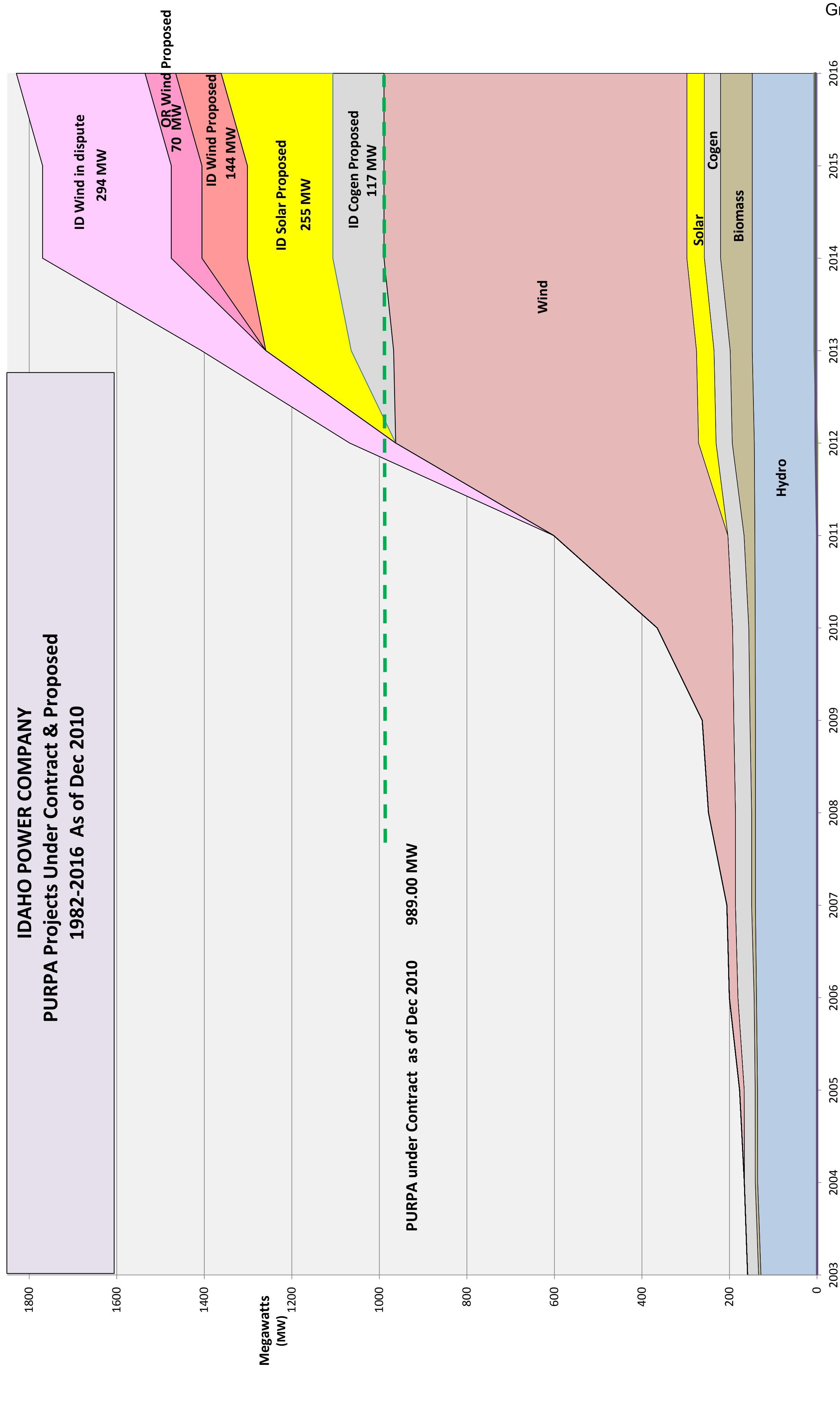
A. Yes, it does.

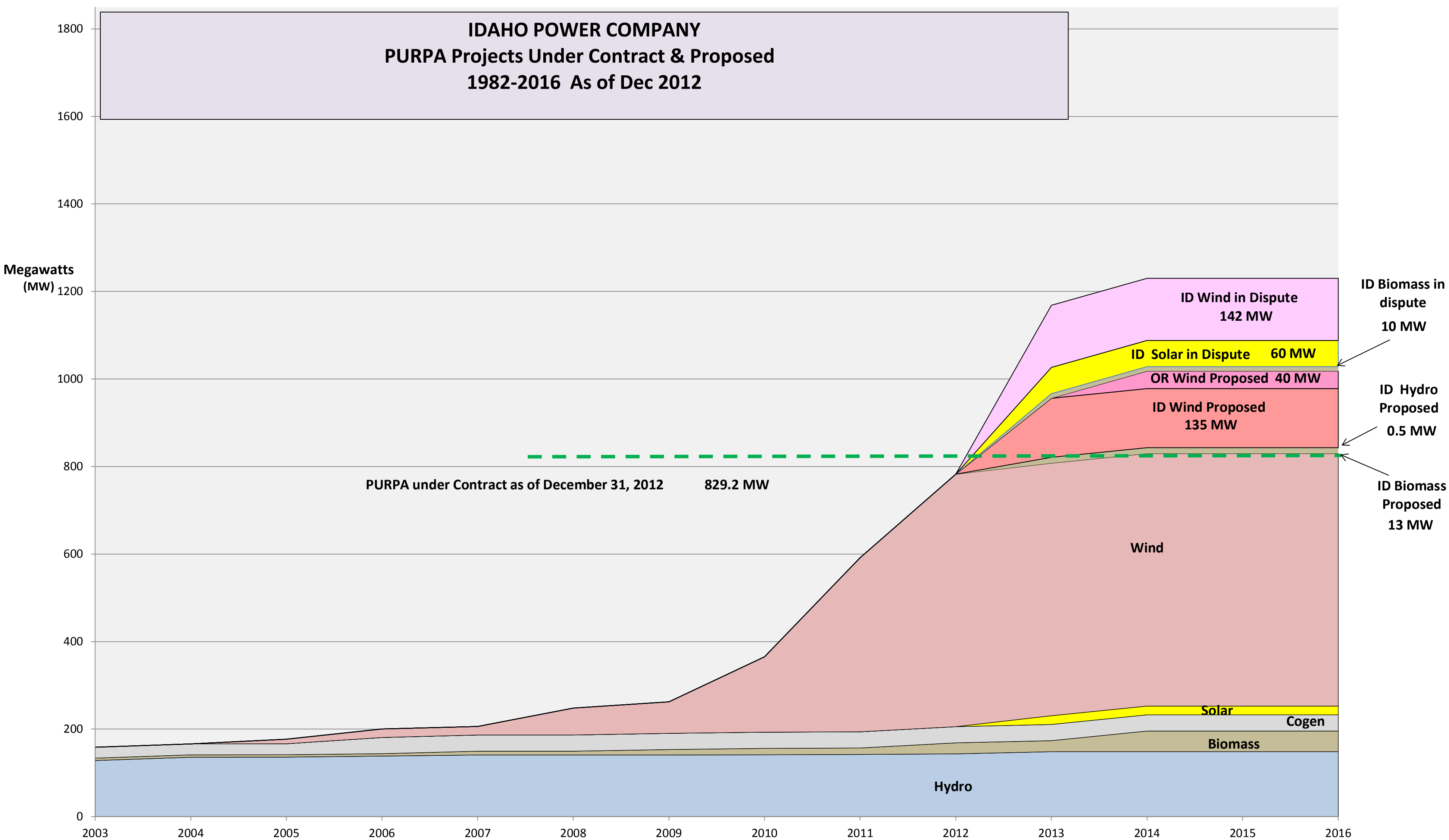
BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Lisa A. Grow
QF Development on Idaho Power's System

February 4, 2013


IDAHO POWER COMPANY
PURPA Projects Under Contract & Proposed
1982-2016 As of Dec 2010
PURPA under Contract as of Dec 2010 989.00 MW
ID Wind in dispute
294 MW
OR Wind Proposed
70 MW
ID Wind Proposed
144 MW
ID Solar Proposed
255 MW
ID Cogen Proposed
117 MW
Wind
Solar
Cogen
Biomass
Hydro
Megawatts
(MW)
0
200
400
600
800
1000
1200
1400
1600
1800
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016


IDAHO POWER COMPANY
PURPA Projects Under Contract & Proposed
1982-2016 As of Dec 2012
Megawatts (MW)
1800
1600
1400
1200
1000
800
600
400
200
0
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
ID Wind in Dispute 142 MW
ID Solar in Dispute 60 MW
OR Wind Proposed 40 MW
ID Wind Proposed 135 MW
ID Biomass in dispute 10 MW
ID Hydro Proposed 0.5 MW
ID Biomass Proposed 13 MW
PURPA under Contract as of December 31, 2012 829.2 MW
Wind
Solar
Cogen
Biomass
Hydro

Idaho Power Company

PURPA Project Status

As of December 31, 2012

PURPA Under Contract	As of December 2010	As of December 2012
Hydro	148.0	148.1
Biomass	72.0	47.2
Cogen	37.0	37.0
Solar	40.0	20.0
Wind	692.0	576.9
Sub Total	989.0	829.2
PURPA Proposed		
Hydro	5.8	0.5
Biomass	3.0	13.2
Cogen	117.0	0.0
Solar	255.0	0.0
Id Wind	144.0	135.0
Ore Wind	70.0	40.0
Sub Total	594.8	188.7
PURPA In Dispute *		
Wind	294.0	142.0
Solar		60.0
Biomass		10.4
Sub Total	294.0	212.4
Total	1,877.8	1,230.3

Note- In dispute includes all projects that currently have filed disputes with Idaho Power Company, the Idaho Commission, or the Oregon Commissions.

Proposed

Jack Ranch Wind	80.00	
Lava Beds Wind	20.00	
Notch Butte Wind	20.00	
Tumble Weed Wind	15.00	
Subtotal		135.00
Oregon Wind	40.00	
Subtotal		40.00
Milner Biomass	12.00	
Bannock Biomass	1.20	
Subtotal		13.20
8 mile Hydry	0.40	
Bliss	0.07	
Subtotal		0.47
Total		188.67

In Dispute

Grouse Creek I wind	21.00	
Grouse Creek II wind	21.00	
Rainbow Wind	20.00	
Rainbow West Wind	20.00	
Murphy Wind	20.00	
Murphy Mesa Wind	20.00	
Murphy Flats Wind	20.00	
Subtotal		142.00
Grand View II Solar	20.00	
Grand View III Solar	20.00	
Grand View VI Solar	20.00	
Subtotal		60.00
Kootenai Biomass	3.20	
Hidden Hollow II	3.20	
Swagger Farms Biomass	2.00	
Double B Biomass	2.00	
Subtotal		10.40
Total		212.40

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UM 1610

IN THE MATTER OF PUBLIC UTILITY	)
COMMISSION OF OREGON	)
INVESTIGATION INTO QUALIFYING	)
FACILITY CONTRACTING AND PRICING	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

M. MARK STOKES

February 4, 2013

TABLE OF CONTENTS

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 83702.

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 Water and Resource 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, and I also hold a Master's Degree in Business Administration from Northwest Nazarene University. I am a registered Professional Engineer in the state of Idaho, and I have attended the University of Idaho's Utility Executive Course.

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 17 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, Inc. In this role, I was responsible for managing the overall operation of Ida-West Energy 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, operations planning, and short-term load forecasting.

In 2013, I was promoted to Director of Water and Resource Planning as part of combining the Power Supply Planning Department with Water Management. The Water Management Department is responsible for water and weather forecasting, water policy, river engineering, cloud seeding, and stream flow gauging.

I. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide direct testimony for Idaho Power in the Public Utility Commission of Oregon's ("Commission") Docket UM 1610, meant to address various issues related to the implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Commission ordered this investigation into qualifying facility ("QF") contracting and pricing in Order No. 12-146.

Q. What areas or issues will you discuss in your testimony?

A. My testimony will describe the current status of PURPA QF projects on Idaho Power's system and will also address issues related to risk and harm to Idaho Power customers through the implementation of PURPA. My testimony will address the Company's position on the several issues identified for Phase 1 of this docket in the Administrative Law Judge's October 25, 2012, and December 21, 2012, rulings. My testimony will address issues related to: (1) avoided cost pricing methodologies; (2) the published, or standard, rate eligibility cap; (3) disaggregation; (4) intermittent resource, wind, integration costs; (5) contract term; (6) updates to the avoided cost prices; (7) environmental attribute and/or Renewable Energy Certificate ("RECs") ownership; and (8) the concept of a legally enforceable obligation.

Q. Could you summarize your testimony?

A. Yes. First of all, Idaho Power proposes that the Commission continue its long-standing practice of allowing Idaho Power to use avoided cost methodologies and contracting practices in its Oregon jurisdiction that are consistent with those that the Company utilizes in its Idaho jurisdiction.

Standard Rates and Contracts. Idaho Power proposes that the current Surrogate Avoided Resource ("SAR") methodology used to determine standard avoided cost rates for QF projects with less than 10 megawatts ("MW") of nameplate capacity (the "Oregon Method") be adjusted to differentiate rates based upon the type of generation resource that is proposed (i.e., wind, solar, hydro, canal drop hydro, and other) using that resource's capacity factor. Additionally, Idaho Power proposes that standard rates be updated annually with the natural gas forecast published by the U.S. Energy Information Administration ("EIA").

Negotiated Rates and Contracts. Idaho Power's current Oregon Schedule 85 authorizes the use of the same Integrated Resource Plan ("IRP") methodology approved by the Idaho Public Utilities Commission ("Idaho Commission") for QFs over 10 MW of nameplate capacity to be used as the starting point for negotiations. Idaho Power proposes no changes to this authorization. However, the Idaho Commission has approved modifications to the Company's IRP methodology that Idaho Power will discuss in this testimony.

Standard Rate Eligibility Cap. Idaho Power proposes that the Commission continue to require the use of standard avoided cost rates and contracts for QF projects with a nameplate capacity of 10 MW or less for all generation types except for wind and solar. For wind and solar QF projects, Idaho Power proposes that standard rates and contracts be required only for those projects that have a nameplate capacity of 100 kilowatts ("kW") or less, consistent with Federal Energy

Regulatory Commission ("FERC") regulations, and with the Company's Idaho jurisdiction.

Wind Integration Charge. Idaho Power proposes to implement a wind integration charge for any wind QF contracting with the Company.

Contract Term. Idaho Power proposes that the Commission continue to authorize contracts for up to 20 years. However, Idaho Power proposes that the currently authorized 15-year fixed price portion of the contract be reduced to 10 years. Additionally, Idaho Power proposes that the Commission not allow a levelized contract price over the term of the contract.

Environmental Attributes/RECs. Idaho Power proposes that the Commission determine that Idaho Power owns all RECs associated with the QF energy that it must purchase from PURPA QF projects.

Legally Enforceable Obligation. Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PURPA contract itself, regardless of whether the utility signs. Further, that there must be some evidence of the utility's refusal to contract, or purposeful delay in the contracting process on the part of the utility, before a QF could avail itself of the remedy of creating a legally enforceable obligation to a particular rate, term, or condition. If the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established.

II. BACKGROUND

A. Current Status of PURPA QF Generation on Idaho Power's System.

Q. Could you please describe the current status of PURPA QF generation on Idaho Power's system?

A. Yes. Idaho Power has a very large amount of PURPA QF generation currently operating on its system, and under contract to come on-line in the near term. In fact, Idaho Power has more PURPA QF generation on its system than any other utility, of any size, in the northwest region of the United States. The amount of QF generation on Idaho Power's system is particularly extreme when considered in proportion to Idaho Power's load, both peak and minimum.

Q. How many QF projects does Idaho Power currently have on its system?

A. As of December 31, 2012, Idaho Power had 108 PURPA QF projects under contract with an estimated nameplate rating of 829 MW. Of those projects, 103 (779 MW) are currently on-line and an additional 5 projects (50 MW) are scheduled to come on-line between now and 2014. Additional information about Idaho Power's QF projects is provided in Exhibit 201.

Q. How does this compare to other regional utilities?

A. The Company researched the QF projects on the systems of five other Northwest utilities, and summarized the results in the tables below. The result is clear: The amount of PURPA QF development on Idaho Power's system significantly exceeds the QF development of any other Northwest utility.

//

//

//

//

//

PURPA Nameplate by State and Utility (MW)

	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	798	18	14					829
PacifiCorp	65	167		179	6	378	20	815
Avista	7				95			102
NorthWestern Energy			163					163
Portland General Electric		14						14
Puget Sound Energy					44			44

2011 Annual Average Load by State and Utility Average Megawatt ("aMW")

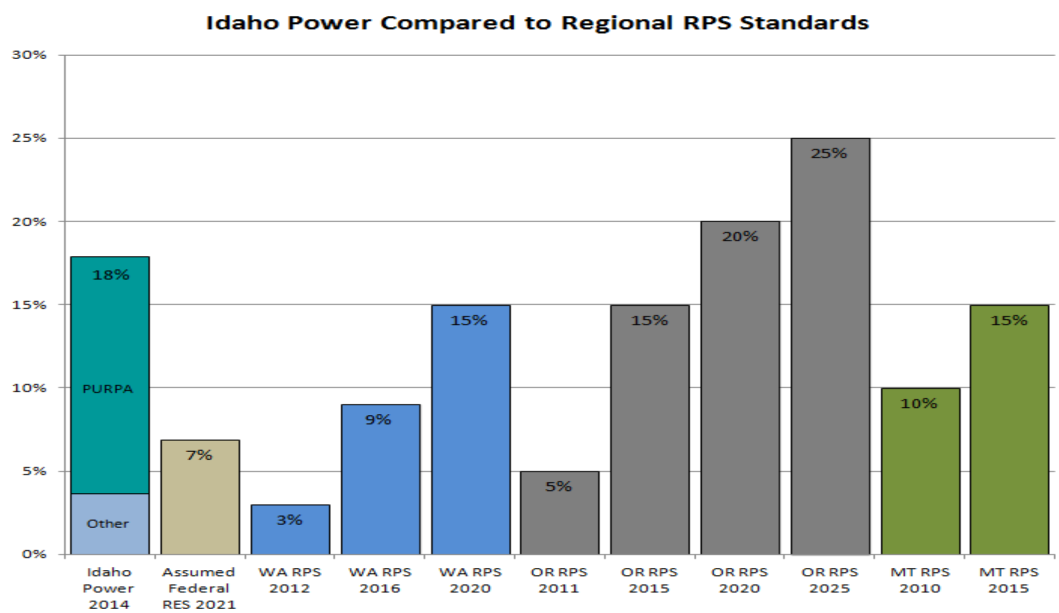
	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	1,771	87						1,858
PacifiCorp	386	1,526		2,735	468	1,133	94	6,342
Avista	382				714			1,096
NorthWestern Energy			733					733
Portland General Electric		2,403						2,403
Puget Sound Energy					2,507			2,507

PURPA Percentage of Average Load by State and Utility

	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	45.0%	20.6%						44.6%
PacifiCorp	16.8%	10.9%		6.5%	1.3%	33.4%	21.3%	12.9%
Avista	1.8%				13.3%			9.3%
NorthWestern Energy			22.2%					22.2%
Portland General Electric		0.6%						0.6%
Puget Sound Energy					1.8%			1.8%

Q. How does the amount of PURPA QF generation Idaho Power has under contract compare to the previously proposed federal Renewable Electricity Standards ("RES") and other state Renewable Portfolio Standards ("RPS") requirements?

A. Idaho Power's most recently acknowledged 2011 IRP assumes a federal RES requirement will be implemented in the near future that will require 15 percent of generation be renewable starting in 2020. The figure below shows how the current level of PURPA QF generation added to Idaho Power's other eligible renewable resources in 2014 compares to the assumed RES requirement (in 2020) and to other regional state RPS requirements. It is important to note that the assumed federal RES requirement also includes subtracting hydroelectric generation from the sales base used to calculate the requirement, consistent with proposals in past draft legislation.



Note: Federal RES includes subtracting hydro generation from the sales base in the calculated requirement.

As shown in the figure above, with just the current level of PURPA generation Idaho Power has under contract coupled with Idaho Power's other qualifying long-term power purchase agreements, the Company would have nearly three times the requirements of the assumed federal RES standard, six years ahead of schedule. Because Idaho Power does not receive the RECs from most of its QF generation, PURPA generation cannot be used to meet any existing or potential renewable standards and Idaho Power cannot represent to customers they are receiving renewable energy from the QFs for which it does not receive the RECs. However, what this comparison does show, at least for Idaho Power, is that even without the motivation provided by a federal RES or state RPS that PURPA has promoted the development of renewable QF projects on Idaho Power's system that far exceed these requirements. The irony is that even though Idaho Power, without having any RPS requirements, may have a much larger percentage of renewable generation incorporated into its system than most utilities that are subject to such requirements, because it does not own the RECs associated with most of the QF generation on its system, the Company cannot claim to have such renewable generation that serves its customers' load.

In comparison to other state RPS requirements, in 2014, Idaho Power will exceed the state of Washington's 15 percent requirement in 2020, the state of Oregon's 15 percent requirement in 2015, and the state of Montana's 15 percent requirement in 2015. In addition, in 2014 Idaho Power would be just shy of meeting the state of Oregon's 20 percent requirement in 2020.

Q. How much does Idaho Power pay for this large amount of PURPA generation?

A. Through December 2012, Idaho Power customers have incurred a cost of a little over $1.2 billion for all PURPA projects that have come on-line since 1982, when the first PURPA project began delivering energy to Idaho Power. The future cost of the current 108 PURPA projects under contract with Idaho Power is estimated to cost Idaho Power customers an additional $2.8 billion over the remaining life of the contracts for a total historical and estimated future cost of $4.1 billion. These costs are shown in Exhibit 202.

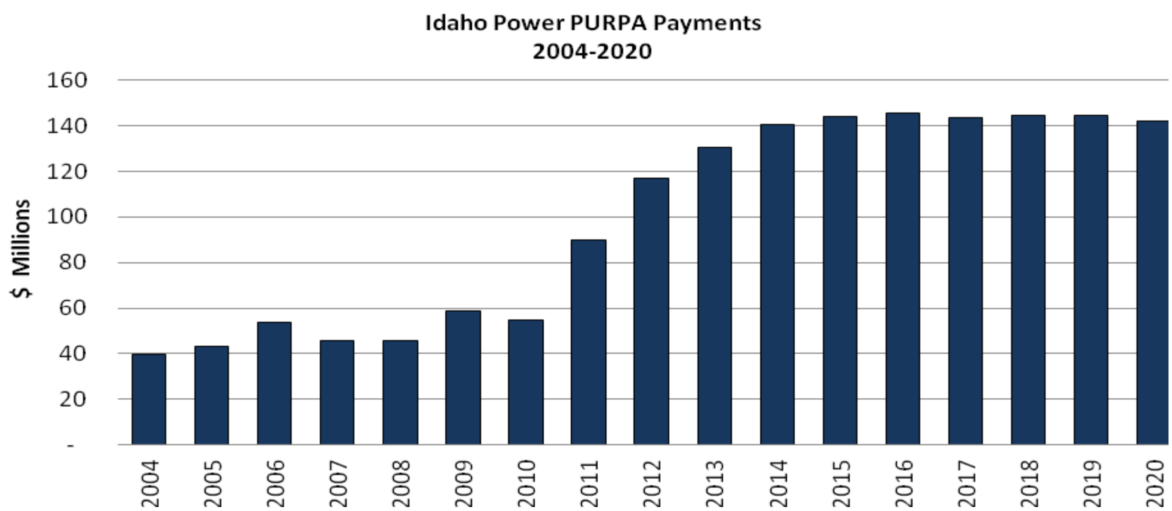
Q. Who pays for PURPA generation?

A. PURPA costs are paid for by Idaho Power's customers as a power supply expense that runs through the annual Power Cost Adjustment ("PCA") mechanism in Idaho and the Annual Power Cost Update ("APCU") and Power Cost Adjustment Mechanism ("PCAM") in Oregon. Each year the power supply expense related to

PURPA QFs is passed through these mechanisms, and will be collected from Idaho Power's customers. The increase in PURPA costs will result in a direct increase to each customer's monthly bill to pay for the power produced by these projects.

Q. Is Idaho Power's power supply expense related to PURPA growing?

A. Absolutely. PURPA expenses are growing at a very rapid pace. The figure below shows the historical and projected increase in PURPA QF power supply expense from 2004 through 2020, and includes existing Oregon QF projects and the contracts approved by the Idaho Commission as of December 31, 2012.[1] These costs are shown in Exhibit 202 and in the figure below.



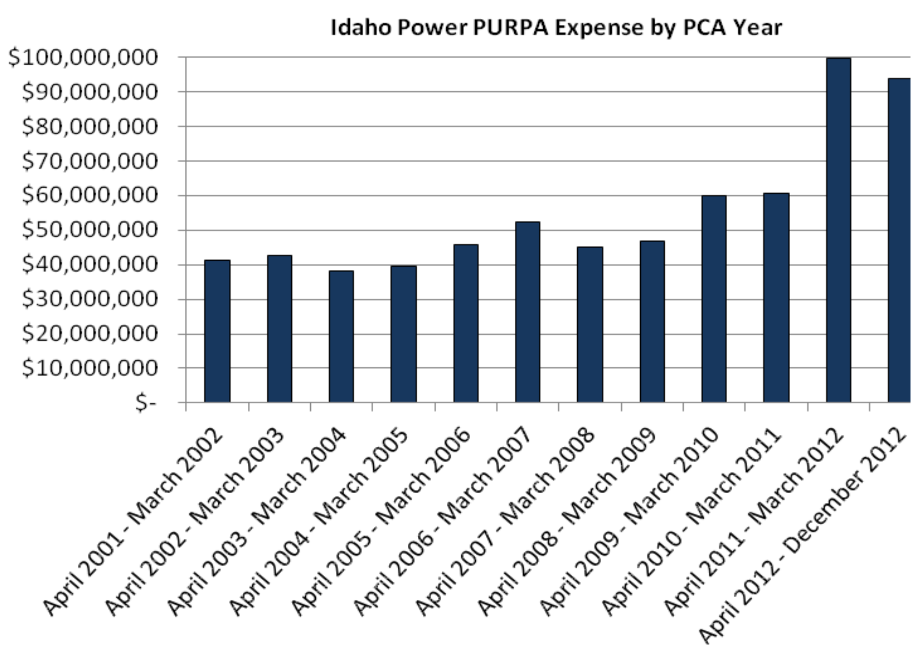
As shown in the figure above, annual PURPA power supply expenses in 2004 were approximately $40 million. It took over 20 years of accumulation of PURPA contracts to reach the $40 million in costs seen in 2004. Five years later, in 2009, that amount grew by 50 percent to approximately $60 million. Just three years later, in 2012, that $60 million nearly doubled to $117 million of annual PURPA

[1] Unlike Oregon, the Idaho Commission requires approval of all contracts, whether standard or non-standard.

power supply costs. That number increases to $140 million by 2014 and, by 2026, it will be $146 million annually, an approximate 365 percent increase in costs from 2004.

Q. How do these large increases in PURPA power supply expenses effect customer rates?

A. As stated earlier, PURPA power supply costs are paid for by Idaho Power's customers through the PCA mechanism in Idaho and the APCU and PCAM mechanisms in Oregon. Each year power supply expense related to PURPA QFs is passed through these mechanisms and will be collected from Idaho Power's customers. The dramatic increases discussed above in annual PURPA power supply costs have a corresponding and equally dramatic impact on customers' bills. As shown in the figure below, the effect of the increase in PURPA power supply costs alone will increase the annual PCA rate in Idaho from the $62.9 million currently approved in base rates to $93.9 million, with three months of the PCA year still remaining.



The level of increase in near term PURPA power supply expense, through 2014, results in dramatic annual increases in customers' bills. In Idaho, the average Schedule 19, Large Power Service, customer's bill will increase by approximately $138,000 annually. The average residential customer will see an increase of just under $100 per year. Annual increases to the Company's largest customers, the Special Contract customers, will range from just over $1 million to more than $3.6 million annually. This price impact is not speculation. It is based entirely upon the projected cost of the currently existing PURPA QF generation, along with the QF projects that have executed power purchase agreements approved by the Idaho Commission. If Idaho Power never acquires another kilowatt of PURPA QF generation, these increases will still take place based upon the current QF projects and approved contracts the Company has now. The impact on customers' bills in Oregon is similar to that in Idaho, and just as dramatic. On an annual basis, customers' base rates and bills are impacted due to increases in net power supply expenses related to PURPA contracts through the APCU in addition to the deferred impact through the PCAM.

Q. Is there a corresponding trend with the amount of generation provided by QFs?

A. Yes. The amount of generation provided, and projected to be provided, by QFs to Idaho Power increases in a similar fashion, as shown in the figure below:

//

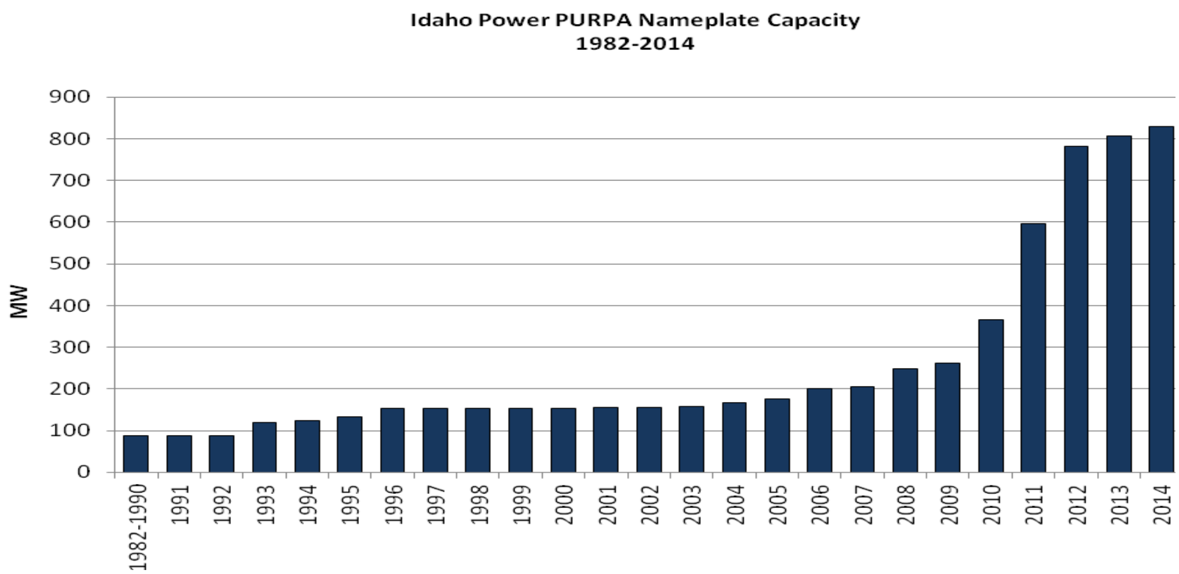
//

//

//

//

//



In summary, over the 10 years between 2004 and 2014, the number of Idaho Power PURPA projects on-line since 2004 has increased by 77 percent (61 projects in 2004 to 108 projects currently under contract), total nameplate capacity has increased 499 percent (166 MW in 2004 to 829 MW currently under contract), and total estimated cost has increased 325 percent ($40 million in 2004 to a projected cost in 2014 of $130 million).

Even if no additional PURPA project contracted with Idaho Power, the amount of energy and financial impact of the existing projects under contract is dramatic. However, PURPA project development within the Idaho Power service territory continues. Prior to the Idaho Commission initiating its GNR-E-11-03 proceeding, Idaho Power saw a significant wave of proposed new QF projects. Some of those project continued through the development process, some suspended their activity, while others (approximately 14 projects with an aggregate nameplate of 212 MW) are currently involved in active disputes with Idaho Power and/or the Idaho Commission. During the pendency of the Idaho Commission proceedings, and prior to Idaho Commission Order No. 32697 on December 18, 2012, Idaho Power had received additional requests from approximately 15 QF projects with an aggregate nameplate rating of approximately 188 MW. In addition to these projects, Idaho Power continues to receive numerous inquiries from potential PURPA projects of all types.

Q. Is the large increase in QF project development limited to the state of Idaho?

A. No. Just last year during a three-day period (January 25, 26, and 27, 2012) the Company received nine new requests for standard price contracts from QFs in its Oregon service territory. These requests were for projects 10 MW and under with prices determined by the SAR avoided cost methodology that was in place at that time. The Company also saw three other QFs located in Idaho attempt to wheel their output to the Company's Oregon jurisdiction to obtain standard SAR-based avoided cost prices. In contrast to those requests from 12 QFs representing approximately 90 MW, Idaho Power currently has five QF projects providing approximately 18 MW located in its Oregon jurisdiction. While the Company has disputed the eligibility of the three proposed Idaho QF projects to obtain standard prices in Oregon, these requests nonetheless make clear that QF development will likely continue as long as higher than actual avoided cost pricing is offered.[2]

Q. Does the recent increase in PURPA projects mean Idaho Power can avoid building any new resources for some time?

A. No. Because a vast majority of the new PURPA contracts are for wind projects, Idaho Power will still have to build new resources in order to meet projected growth in peak-hour demand. Wind resources provide less than 5 percent of capacity on

[2] In Order No. 12-083 the Commission concluded that two of these QFs were in fact ineligible to receive an Oregon standard contract because "the transactions [the QFs] request to enforce do not fall within the parameters of PURPA." Dockets UM 1552 and 1553, Order No. 12-083 at 1 (Mar. 13, 2012).

peak and therefore do little to meet Idaho Power customers' growing summertime peaking needs.

B. Harm to Customers.

Q. What effect does the very large and dramatic increase in PURPA power supply expenses that you have set forth above have on Idaho Power customers?

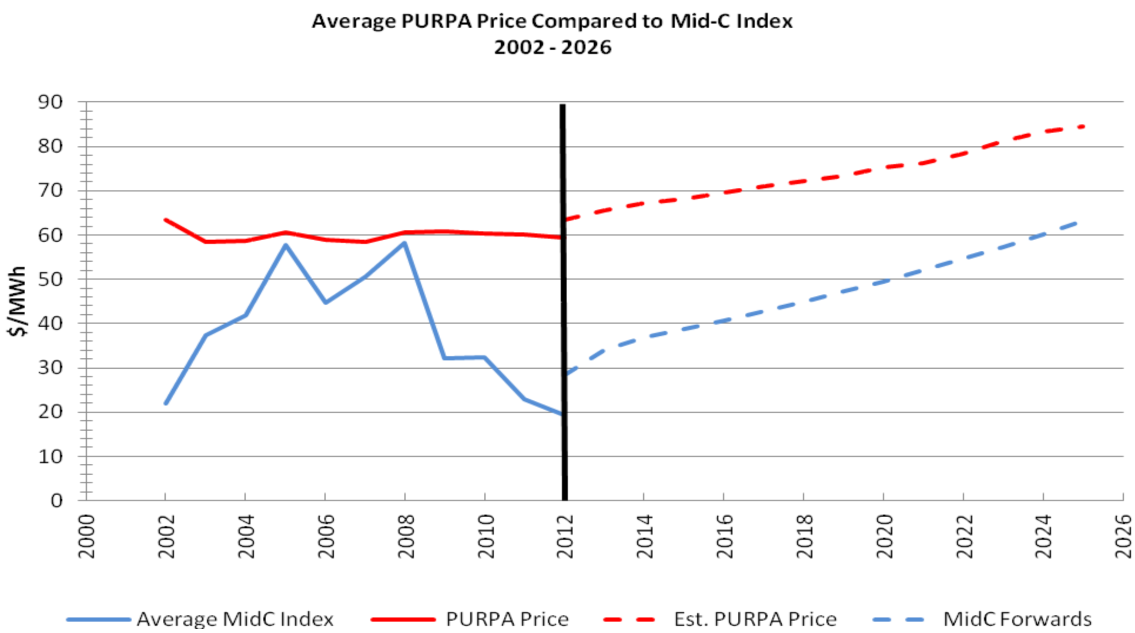
A. The effect is that customers are harmed by the QF transactions that the Company is legally required to enter into. Customers will pay much more for QF generation than they would otherwise pay for Idaho Power to either generate the same amount of electricity from its own generation resources or to purchase that same amount of electricity from the wholesale market. This is directly contrary to the federal definition of avoided cost. It is also directly contrary to the requirement that customers be held indifferent to whether the Company purchased electricity from the QF or otherwise acquired it.

Q. It is clear that customers are paying a lot of money for QF generation, and that this amount will increase substantially. Is this increase acceptable because the amount of generation received from PURPA QFs will also increase substantially?

A. No. If the greatly increased amount of QF generation coming onto the system were priced properly, and if that generation were bringing adequate value to the system, then Idaho Power customers might be indifferent. However, PURPA generation is not currently being priced properly nor is it bringing adequate value to the system. In fact, PURPA projects are providing a very large amount of generation at times when it is not needed, at a price that exceeds the cost to Idaho Power to generate using its own resources, and at a cost that exceeds what Idaho Power can get for it at market. This is extremely harmful to customers.

Q. How can one determine the value that QF purchases bring to the system?

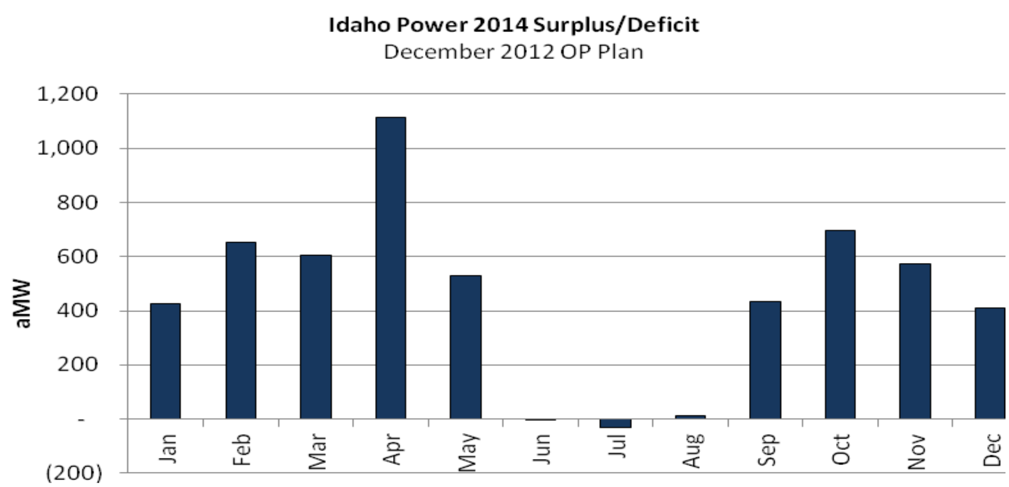
A. An approach to determine the value of QF purchases is to compare PURPA contract prices to historical and forward market prices. Idaho Power's research shows that there has been a significant difference between the historical prices paid to PURPA resources and the Mid-Columbia ("Mid-C") index and, on a forward looking basis, there continues to be a significant difference between PURPA prices and the Mid-C forward market prices. This difference is illustrated in the following figure:



In 2005 and 2008, the average price paid to PURPA projects was reasonably close to the Mid-C index price; however, the Mid-C index was down significantly in 2009 and 2010, and dropped further in 2011, yet the price paid to PURPA projects remained relatively constant. And, as illustrated above, there continues to be a significant gap between PURPA prices and Mid-C forwards out past 2026.

Q. Does Idaho Power need PURPA generation?

A. There are limited times when Idaho Power utilizes this generation to serve load, and the Company reflects such use in its IRP planning process. However, Idaho Power is currently purchasing large amounts of PURPA generation that exceeds the needs of its customers. For example, the figure below shows Idaho Power's projected monthly surplus/deficit position in 2014. Idaho Power is in a surplus position in all months of the year except for slight deficits in June and July, and does not have a need for any additional QF generation outside of those months. Overall, the projected annual average surplus on the Company's system is 451 aMW and this projected surplus includes 253 aMW of PURPA generation. If all of the PURPA generation is removed, the portfolio still has an average surplus of 198 aMW.



The net result is that Idaho Power is buying a significant amount of energy that its customers do not need, at above market prices, and, in many instances, the Company will end up selling that energy back into the market at a significant loss. This is harmful to customers, as it inflates the power supply expenses they must bear.

Q. Could you explain?

A. Yes. To illustrate the significance of this issue, one must only look at the differential between what Idaho Power *will* pay for PURPA generation in 2013 and the amount it *would* pay to purchase the same amount of generation as a "firm" product in the Mid-C market. That differential is on the order of $74 million—an overpayment of $74 million in one year. For 2014, the differential in QF purchase price and market price results in an overpayment to the QFs of $70 million. For the 10-year period between 2013 and 2022, this differential results in an average overpayment of $60 million per year, totaling $602 million. The present value of this overpayment is close to half a billion dollars ($443,000,000).

That is only part of the harm to customers. There is an additional cost associated with moving unneeded QF generation to market when it is not needed to serve customers. Not only are customers overpaying for generation the system does not need, but when the QF generation cannot be used to serve Idaho Power's load (10 months where it is surplus), it must be moved to market. To move this QF generation to market at Mid-C, the Company will have to sell it as a standard "firm" product.

Additionally, transmission expenses are incurred to move energy to the Mid-C market. Non-firm energy typically trades at a discount to a firm energy product—this discount may be as much as $5 per megawatt-hour ("MWh"). So, if on average, Idaho Power incurs an additional $3 per MWh to firm the energy and an additional $3 per MWh in transmission costs plus transmission losses of $1.50 per MWh, with PURPA generation projected to exceed 2.4 million MWh per year beginning in 2013, this adds an additional $18 million per year. This increases the $70 million loss to $88 million per year. While these are just estimates, they illustrate the type of additional costs that will be incurred to get PURPA generation to the market.

Q. Are there any other costs that are unaccounted for in the current avoided cost methodologies that harm customers?

A. Yes. There are a number of additional costs that Idaho Power and its customers may incur as a result of the amount of intermittent PURPA resources currently under contract. Although difficult to quantify, additional costs may be incurred in the following areas:

1. New Resources. It may be necessary for Idaho Power to add additional utility-owned generation resources to assist with integration of variable QF resources;

2. Maintenance Costs. As a result of operating its existing resource portfolio differently, Idaho Power may incur additional maintenance costs if, for example, thermal units are cycled more frequently to assist with integration of variable QF resources; and

3. Imputed Debt. Idaho Power's borrowing costs may increase if Idaho Power's credit ratings are impacted by the amount debt rating agencies impute on Idaho Power's balance sheet. The amount of imputed debt will depend on the magnitude of the PURPA obligations and the agency's assessment of the likelihood that Idaho Power will be able to recover these costs.

The current indications are that Idaho Power's customers are paying above-market prices for significant amounts of energy that the system does not need, and they will continue to do so at substantial harm well into the future.

Q. Most of the Company's data is based on nameplate capacity numbers of the various QFs, but QFs do not typically generate at nameplate capacity do they?

A. No, not all the time. However, sometimes they do and when they do, Idaho Power must have the infrastructure and ability to handle the generation as it is delivered to the electric system. There are several times when QF generation has and will generate at or close to nameplate capacity. For example, on December 21, 2011, Idaho Power received a large amount of energy from its QF wind resources. On this day, Idaho Power received 7,028 MWh (293 aMW) from the 20 PURPA wind projects on-line (nameplate rating of 398 MW). Based on an average energy price contained in those contracts, Idaho Power incurred a power purchase expense of approximately $535,000 for the day for the wind generation ($76.12 per MWh). On that same day, the short-term, daily average Mid-C market price was $29.75 per MWh. If Idaho Power had purchased the same amount of energy as provided by the PURPA wind projects on that day, Idaho Power would have only incurred a power purchase expense of approximately $209,000. Thus on December 21, 2011, the PURPA wind energy power purchase expenses were $326,000 greater than alternative market purchases. These additional costs were included in the annual PCA and collected directly from Idaho Power's customers. If this example were an isolated incident, the Company might not be so concerned. However, these circumstances occur frequently enough to suggest a thorough examination is warranted, which is the purpose of this filing.

The December 21, 2011, example is not only a good example of QF generation operating at or near nameplate capacity but also a good example of what is wrong with the current avoided cost methodology employed in Oregon. Avoided cost is supposed to mean the incremental cost to Idaho Power of electric energy or capacity or both which, but for the purchase from the QF, Idaho Power would generate itself or purchase from another source.[3] When customers must pay more for QF generation than what that generation can be sold at market at times when it cannot be used to serve load, customers are no longer being held indifferent to the QF transaction.

Q. Is wind generation the main concern of Idaho Power with regard to QF generation?

[3] 18 C.F.R. § 292.101(b)(6).

A. Wind generation is a major concern because of the extremely large quantity that is currently operating on the Company's system, the additional projects that have been approved with the long-term power purchase agreements that are scheduled to come on-line in the near future, and the continued interest in QF wind development. However, Idaho Power's concerns extend to all PURPA QF projects, regardless of the generation technology or motive force.

C. <u>Current Avoided Cost Pricing Methodologies</u>.

Q. Could you describe the methods currently utilized in Oregon to establish avoided cost prices?

A. Yes. The Commission currently utilizes two methodologies for determining avoided cost: (1) the standard price calculation is determined using the same Commission-ordered avoided cost methodology used by Portland General Electric Company ("PGE") and PacifiCorp (the "Oregon Method") and (2) the IRP-based methodology is used to determine prices for negotiated non-standard contracts.

Q. What determines a QF's eligibility for prices determined by the two different methodologies?

A. The determination of which methodology is used is based on the size of the QF project. QFs of all resource types that have a nameplate capacity of 10 MW or less receive a standard price calculated using the Oregon Method. QFs with a nameplate capacity greater than 10 MW negotiate a non-standard contract, which is based on the avoided cost price determined using the IRP methodology.

1. <u>The Oregon Method</u>.

Q. Has Idaho Power always used the Oregon Method to determine the avoided cost for standard contracts?

A. No. The Oregon Method was ordered by the Commission after a lengthy investigation in Docket UM 1129. In that docket, the Commission concluded that "accurate calculation of avoided costs requires differentiation when a utility is in a resource sufficient position versus a resource deficient position," and ordered that PGE and PacifiCorp base avoided cost prices on market prices when the utility is in a resource sufficient position and on the variable and fixed costs of a natural-gas, combined-cycle combustion turbine ("CCCT") when the utility is resource deficient. (Order No. 05-584 at 26; Docket UM 1129.) The Commission substituted the IRP-indicated resource as the proxy resource the following year, in Order No. 06-538. However, the Commission did not require Idaho Power to adhere to the Commission-ordered methodology for calculating avoided cost prices for "administrative efficiency." Instead, the Commission authorized Idaho Power to use the method used in Idaho for calculating avoided costs because the "administrative burdens to Idaho Power of developing and applying new avoided cost methodologies in Oregon outweigh the potential benefits and justify allowing Idaho Power to continue to use the SAR methodology." (Order No. 05-584 at 26; Docket UM 1129.)

Q. When did Idaho Power begin using the current Oregon Method to determine avoided cost prices?

A. On March 15, 2012, 30 days after acknowledgment of the Company's 2011 IRP, Idaho Power filed new avoided cost prices using the then ordered Idaho SAR methodology (Docket UM 1593). At the same time as the March 15 compliance filing, Idaho Power submitted an Application to Revise the Methodology Used to Determine Standard Avoided Cost Prices, which included a request to use a different methodology than the Idaho SAR. (Docket UM 1590). In response to the Commission Staff's suggestion to use the Oregon Method to address concerns raised by the Company regarding avoided cost prices determined using the Idaho SAR methodology during times of resources sufficiency, the Company filed revised avoided cost prices on April 20, 2012. This was the first time the Company used the

Oregon Method to determine avoided cost prices for standard contracts. These were approved on April 25, 2012, in Order No. 12-146.

Q. At a high level, could you describe the Oregon Method?

A. As I stated above, the Oregon Method is the same Commission-ordered avoided cost methodology used by PGE and PacifiCorp since Order No. 05-584 in Docket UM 1129. This methodology incorporates differentiating the calculation of avoided costs for a utility in a resource deficit position from a utility in a surplus position. This historical differentiation is based on recognition that a utility's avoided costs differ depending on the resource position of the utility.

Simply stated, in a period of resource deficiency, the calculation of avoided costs reflects the variable and fixed costs of a natural gas-fired CCCT. In a resource sufficient period, the Company uses on-peak and off-peak market based prices to determine avoided costs prices.

Q. Please describe how capacity and energy costs are determined when a Company is in a resource deficit position.

A. The calculation of avoided costs reflects the variable and fixed costs of a CCCT. The CCCT costs used in the determination of Idaho Power's current standard avoid cost prices are the same costs included for the Company's most recent CCCT brought on-line, the Langley Gulch power plant.

Since CCCTs are built as base load units that provide both capacity and energy, the Oregon Method provides that the fixed costs of the CCCT unit are split into capacity and energy components. To determine the portion of fixed costs allocated to capacity, Idaho Power uses the fixed cost of a simple-cycle combustion turbine ("SCCT") to define the portion of the fixed cost of the CCCT that is assigned to the capacity component. Fixed costs for the CCCT in excess of SCCT costs are assigned to the energy component of avoided costs.

Q. How is the variable production cost of the avoided energy component determined?

A. The variable production (fuel) cost of the CCCT is used to determine the avoided energy costs. The fuel cost of the CCCT is based on the most recent gas forecast at the time of the Company's last avoided cost filing. The Company's current avoided cost rates use the Northwest Power and Conservation Council's ("NPCC") Update to the Council's Forecast of Fuel Prices (August 10, 2011). The fuel cost of the CCCT defines the variable energy costs. Avoided energy costs are differentiated between on-peak and off-peak periods.

Q. How does the Company determine market based prices during a period of resource sufficiency?

A. The Company uses forward price curves for heavy load and light load hours at Mid-C from the Inter-Continental Exchange (ICE).

2. <u>The IRP Methodology</u>.

Q. In general, please describe the IRP-based methodology that has been used by the Company to determine negotiated, non-standard, avoided cost prices.

A. Generally, the IRP-based methodology calculates the projected future cost of Idaho Power's preferred resource portfolio without the QF resource, and then again with the QF resource 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 QF's generation, using the costs associated with a CCCT, 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.

Q. Please describe how the individual cost components of the avoided cost are determined.

A. The IRP methodology consists of two components: (1) the avoided cost of energy and (2) the avoided cost of capacity. 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 total portfolio cost of a "Base Case," which includes the preferred resource portfolio from the IRP, is compared to a "Study Case," which includes the same IRP preferred portfolio with the PURPA resource added. The difference in the total portfolio cost of these two cases, on a monthly basis, is divided by the MWh of generation from the PURPA resource to establish an avoided cost of energy in dollars per MWh. This establishes the avoided cost of energy component.

Q. How is the avoided cost of capacity calculated in the IRP methodology?

A. To determine the avoided cost of capacity, the capital or fixed cost of a CCCT (taken from the IRP) is used as the surrogate resource that Idaho Power would avoid building. The cost in dollars per kW-month for the CCCT is first multiplied by the nameplate capacity of the PURPA resource and then converted to an annual cost by multiplying by 12. This cost is then multiplied by the peak-hour capacity factor of the PURPA resource to account for the amount of capacity the PURPA resource will provide during Idaho Power's peak-hour load period between 3:00 p.m. and 7:00 p.m. in July. Due to the uncertain and variable nature of intermittent resources, a 90 percent exceedance capacity factor calculated from representative projects in Idaho Power's service territory is used as a benchmark. If the peak-hour generation of the PURPA resource exceeds the generation of the benchmark resource for that period, the PURPA resource will receive a proportionally higher peak-hour capacity factor that is used to calculate the avoided cost of capacity. Likewise, if the PURPA resource provides less generation than the benchmark resource during the peak-hour period, the PURPA resource will receive a proportionally lower peak-hour capacity factor.

While base load resources such as biomass and geothermal may be capable of producing 100 percent of nameplate during the peak-hour period, forced outages remain a possibility. Therefore, applicable forced outage rates taken from NPCC's Sixth Power Plan are used to derive the peak-hour capacity factor for these types of resources in calculating the avoided cost of capacity. For all resource types, the resulting avoided cost of capacity is held constant for all months of the year in the analysis.

The avoided cost of energy and the avoided cost of capacity are then added together to get a monthly avoided cost rate. However, the avoided cost of capacity is excluded until the first month Idaho Power's load and resource balance shows a peak-hour deficit based on existing and committed resources as identified in the IRP.

III. PROPOSED AVOIDED COST METHODOLOGIES

Q. Are you proposing changes to how Idaho Power's Oregon avoided cost rates are calculated?

A. Yes, I am. In order to maintain consistency between Idaho Power's Idaho and Oregon avoided cost rates, and for administrative efficiencies, Idaho Power is proposing the calculation of its avoided cost rates in the state of Oregon be similar to the methodologies recently adopted in the state of Idaho by the Idaho Commission.

In Order No. 05-584, the Commission authorized Idaho Power to continue to use the SAR methodology in Oregon, even though the Commission adopted a different methodology for calculating standard prices for both PGE and PacifiCorp. The Commission's decision to allow Idaho Power to use a different method than both

PGE and PacifiCorp was based on administrative efficiency. The Commission noted the fact that "Idaho Power exclusively uses the SAR methodology in its Idaho service territory, where it serves far more customers than its Oregon service territory." Therefore, the Commission found that "administrative burdens to Idaho Power of developing and applying new avoided cost methodologies in Oregon outweigh the potential benefits and justify allowing Idaho Power to continue to use the SAR methodology."

Q. Were the recent changes adopted by the Idaho Commission radically different from the current methods used to calculate Idaho Power's avoided cost rates in Oregon?

A. No, I do not believe so. In Idaho, a SAR model is still used to calculate published rates for QF projects smaller than the threshold cap. For projects larger than the cap, Idaho Power continues to use the AURORA model as part of the IRP methodology to determine avoided cost rates for larger projects.

Q. Can you explain what changes Idaho Power is proposing that will align avoided cost rates for the Company in Idaho and Oregon?

A. Yes, I can. The next two sections will detail the proposed changes for, first, the Oregon Method used to calculate standard avoided cost rates for smaller QF projects and, second, the IRP methodology that is used to calculate avoided cost rates for larger QF projects.

A. Proposed Changes to the Standard Rate Methodology (SAR/Oregon Method).

Q. What changes are you proposing for the Oregon Method?

A. For the Oregon Method used to calculate standard rates, Idaho Power is proposing that energy and capacity values be calculated separately so that published rates for various resource types can be based on the capacity each type of resource actually provides to the electrical system. Although capacity and energy rates would be calculated separately, the two would be combined to produce a single published rate for each of the various resource types, including base load (biomass, geothermal, etc.), hydro, canal drop hydro, wind, and solar. Thus, there would be five different pricing schedules, one for each resource type, for Oregon standard rates.

Because all resource types do not provide the same value in terms of when they provide capacity, and none provide the dispatch capability of a CCCT, this modification acknowledges some of the different characteristics of each resource type. This was the biggest change to the SAR methodology made recently in Idaho, and while it does not fully account for the different characteristics between resources, Idaho Power believes it is a step in the right direction.

To determine the avoided cost of capacity, the capital or fixed cost of a CCCT (taken from the IRP) in dollars per kW-month is first multiplied by the nameplate capacity of the QF resource and then converted to an annual cost by multiplying by 12. This cost is then multiplied by the peak-hour capacity factor of the QF resource to account for the amount of capacity the QF resource will provide during Idaho Power's peak-hour load period between 3:00 p.m. and 7:00 p.m. in July.

While base load resources such as biomass and geothermal may be capable of producing 100 percent of nameplate capacity during the peak-hour period, forced outages remain a possibility. Therefore, applicable forced outage rates taken from the NPCC's Sixth Power Plan are used to derive the peak-hour capacity factor for these types of resources in calculating the avoided cost of capacity. For all resource types, the resulting avoided cost of capacity is held constant for all months of the year in the analysis. The 90 percent exceedance criterion is consistent with Idaho Power's evaluation of the different resource types in the Company's IRP, and results in the following peak-hour capacity factors: hydro (33.9 percent), canal drop hydro (67.1 percent), wind (3.9 percent), and solar (33.2 percent).

In Idaho, a utility's resource capacity sufficiency/deficiency has not historically been used in the SAR methodology, but was recently adopted by the Idaho Commission. Because resource capacity sufficiency/deficiency is already used in the Oregon Method, Idaho Power is proposing to continue using the existing Oregon Method where the first deficit year is determined by the first uncommitted resource identified in the IRP.

The only other change to the SAR methodology adopted in Idaho, and that Idaho Power is proposing for the Oregon Method, is the source used for the natural gas price forecast. Historically, Idaho has used the natural gas price forecast published by the NPCC. The main problem identified with using the NPCC forecast was the infrequent release of updates, especially given the changes that have occurred in the natural gas industry and pricing in the last few years. To address this problem, the Idaho Commission is now using the natural gas price forecast published by the EIA, which is updated annually.

Idaho Power is also using the EIA gas price forecast in preparing the Company's 2013 IRP and is proposing to use the same source for the Oregon Method to calculate standard avoided cost rates in Oregon. A separate issue related to the natural gas price forecast and other inputs used in the Oregon Method is the frequency of updating the inputs and the standard avoided cost rates. I will address this issue later in my testimony.

Q. With the modifications to the Oregon Method that Idaho Power is proposing, what would the 20-year, levelized, published avoided cost rates be for each type of project assuming a 2013 on-line date?

A. With Idaho Power's proposed modifications to the Oregon Method, the 20-year published avoided cost rates for a 2013 project would be: other/base load ($53.17/MWh), hydro ($49.16/MWh, canal drop hydro ($51.45/MWh), wind ($47.08/MWh), and solar ($49.11/MWh). Exhibit 203 of my testimony shows each of these rates broken down into the energy and capacity components. Also, please note the $47.08/MWh rate for wind projects does not include an adjustment for the cost of wind integration, which I will address later in my testimony.

B. <u>The Incremental Cost IRP Methodology</u>.

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

A. Yes. The previously approved IRP methodology was a significant improvement over the SAR methodology and the Oregon Method. It is a far more accurate approximation of avoided cost than the more generic SAR-based methodologies. The IRP methodology begins to take into account aspects of need, value, and timing of the QF's proposed generation when establishing the avoided cost rates. One of the most important improvements of the IRP methodology over the SAR-based methodologies 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 Oregon's implementation of the IRP methodology for Idaho Power?

A. No. Idaho Power requests that the Commission continue to authorize the use of the same IRP methodology approved by the Idaho Commission for QFs over the standard rate eligibility cap to be used as the starting point for negotiations as specified in the currently approved Schedule 85.

Q. Have there been any recent changes to the IRP methodology approved by the Idaho Commission?

A. Yes. The IRP methodology has recently been modified in Idaho in order to better estimate Idaho Power's avoided cost, and to better align the methodology with the definition of avoided cost from federal regulations. While the IRP methodology, as previously approved by the Idaho Commission and implemented by Idaho Power, was a significant improvement over the SAR-based methodologies, it still had a number of problems that resulted in significant harm to Idaho Power's customers. For these reasons, the Idaho Commission has authorized a modification to the way in which the IRP methodology calculates avoided cost rates, and adopted the use in Idaho of the incremental cost IRP methodology, not only for Idaho Power, but also for Rocky Mountain Power (PacifiCorp), and for Avista Corp. *See* Idaho Commission Case No. GNR-E-11-03, Order No. 32697, pp. 20-21, Dec. 18, 2012.

Q. Could you please provide some examples of the problems that exist with the previously approved 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 previously implemented by Idaho Power:

1. The avoided cost produced by the former IRP methodology relies too heavily upon forecasts of future market prices. Under the former 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 former 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; and

3. The former 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 was 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. The federal regulations define avoided cost as: "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 incremental costs 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 are the <u>incremental 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, the incremental cost 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 (contract term) to determine the avoidable incremental cost during each hour and then (2) a methodology to convert the hourly incremental costs into avoided cost rates. The incremental cost IRP methodology addresses both of these items.

Q. Please describe the incremental cost IRP methodology.

A. The incremental cost IRP methodology differs from the former application of the IRP methodology 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 the incremental costs the utility would incur, but for the addition of the QF resource;

2. A change in the resource type, from a CCCT to a SCCT, 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. Inclusion of all QF contracts at the time they are signed, and exclusion of all QF contracts that are terminated in the IRP pricing analysis. Idaho Power's resource portfolio, for purposes of calculating a future avoided cost, can change whenever a QF project is added to, or taken out of the utility's resource portfolio. 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, or removed from, the portfolio must be taken into account if avoided cost is to be determined properly.

1. Avoided Cost of Energy.

Q. Could you summarize how the incremental cost IRP methodology calculates the avoided cost of energy?

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 was formerly calculated in the IRP methodology?

A. Under the former 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 incremental cost IRP 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 <u>incremental costs that Idaho Power would have incurred but for the QF generation</u> is the basis for QF contract pricing. In both the former implementation of the IRP methodology and the incremental cost IRP 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 incremental cost IRP 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 incremental cost IRP 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 the former 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 incremental cost IRP 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 the former 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 take on the risk that the value of the generation received from the QF will differ from the QF's contract price. The incremental cost IRP methodology, used 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.

Q. Please describe in more detail the components of the incremental cost IRP methodology.

A. As discussed earlier in my testimony, the former IRP methodology already calculates 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, the incremental cost IRP methodology bases the avoided cost of energy upon the incremental energy cost the utility would incur, but for the QF output. In order to do this, the AURORA model is used to determine the highest displaceable incremental cost being incurred during each hour of the QF's proposed contract term. 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 with 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 incremental cost model?

A. Longer term firm purchases, such as Idaho Power's 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 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, the incremental cost of Idaho Power's hydroelectric resources are not considered 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 incremental cost methodology does not attempt to incorporate the incremental cost of Idaho Power's hydroelectric projects.

Q. Are there times when the incremental cost calculated with the incremental cost IRP 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. The incremental cost model does not, however, assign any negative incremental costs to the QF generation, and is stopped at zero.

Q. Do you have an example of the frequency of times where the incremental cost results are zero?

A. Yes. As an example, out of a total of 157,776 hours in an AURORA simulation for a 22 MW wind project, the incremental cost IRP methodology assigned an avoided cost of $0/MWh in 3,515 hours. This works out to about 2 percent of the time, or 195 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 no transmission constraints limiting their output, then there likely is not a demand for energy at the dispatch price of the coal-fired units.

Q. Can you provide an example to demonstrate how the incremental cost IRP methodology calculates the avoided cost of energy?

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 greater 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 purchase 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 SCCT with a 11,000 Btu/kWh heat rate, $5.00/MMBtu natural gas, and variable operations and maintenance costs of $5/MWh) and the cost of a market purchase during the same hour is $30/MWh, then the avoided cost for that MWh of energy is $60/MWh.

2. Avoided Cost of Capacity.

Q. Is Idaho Power proposing changes in the method used to determine the avoided cost of capacity in the incremental cost IRP methodology from the method used in the former IRP methodology?

A. No. Idaho Power is not proposing any changes to the method used for determining the avoided cost of capacity using the incremental cost IRP methodology.

Q. Does the incremental cost IRP methodology use the same resource inputs in the determination of the capacity component of avoided cost?

A. No. Although the method 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 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 former methodology uses the fixed costs of a CCCT taken directly from the Company's IRP analysis, the incremental cost IRP methodology uses the fixed costs of a large frame industrial SCCT, taken directly from the Company's IRP analysis for determining the capacity component of avoided cost going forward.

Because both the former IRP methodology, and the incremental cost IRP methodology, include both capacity and energy components of avoided cost that are determined independently, it is inappropriate to set the capacity component of avoided cost with the capital cost of a CCCT when the Company's need for capacity can be served by a SCCT. 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, but will be paying for the higher capital cost of a CCCT.

Q. Does the incremental cost IRP methodology continue to use the peak-hour capacity factor calculation that is utilized in the former IRP methodology?

A. Yes.

Q. Are there any other differences between the former IRP methodology and the incremental cost methodology that you would like to discuss?

A. Yes. With the incremental cost IRP methodology, any QFs with signed contracts and any QFs whose contracts are terminated are 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, whenever a new QF contract is signed, or a previously existing QF contract is terminated, the incremental cost IRP methodology includes those projects in the resource portfolio used to calculate the avoided cost price.

As stated earlier, Idaho Power's resource portfolio, for purposes of calculating a future avoided cost, can change whenever a QF project enters the portfolio if that QF is considered part of the resource portfolio. If 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 former avoided cost determination from the current methodologies—be it the SAR or the former 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, or leaves the queue, if that QF is considered to be part of the resource portfolio. For example, if the resource portfolio includes all QF projects that are operating and all QF projects with signed contracts and a new QF proposes a project, the incremental cost will be based upon this resource portfolio that includes all the QF contracts. However, once this new proposed QF executes a contract with Idaho Power, it will also be included in the resource portfolio, thus potentially changing the Idaho Power incremental displaceable generation resource in a given hour. For example—the IRP model with the existing resource portfolio indicates that in a given hour, the highest cost displaceable resource is 10 MW of an Idaho Power natural gas resource. A new QF project of 10 MW is proposed and executes a contract with Idaho Power, this new QF project therefore will displace and be awarded the price associated with this 10 MW displaceable resource in that specific hour. However, when another QF project is proposed, the displaceable resource price for that specific hour will now be different due to the fact that the previous QF resource displaced the Idaho Power 10 MW resource.

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 indicative QF contract rates developed using the incremental cost IRP methodology?

A. Yes. Exhibit 204 provides indicative prices for several different types of QF projects—a 20 MW base load project, a 20 MW canal drop project, a 20 MW fixed PV solar project, and a 22 MW wind project.

IV. <u>STANDARD/PUBLISHED RATE ELIGIBILITY CAP</u>

Q. What is the standard rate eligibility cap?

A. The standard rate eligibility cap refers to the size of QF projects that are eligible to receive standard avoided cost rates and a standard contract. These standard rates are based upon the cost of a hypothetical SAR, and sacrifice accuracy in favor of simplicity and convenience. QF projects over the eligibility cap must negotiate rates, and the IRP methodology is used as the basis for the negotiated rates. IRP methodology-based rates are a much more accurate approximation of a utility's avoided cost as defined by FERC.

Q. Does the Company have a recommendation related to the standard rate eligibility cap?

A. Yes. Idaho Power Company requests that the Commission reduce the eligibility cap applicable to standard contracts for wind and solar QFs to 100 kW. Currently, any

QF is eligible for a standard contract if its nameplate capacity is less than 10 MW.[4] Idaho Power requests that the Commission lower this eligibility cap to 100 kW for wind and solar QFs, thus allowing most wind and solar QF contracts to be individually negotiated, and prices to be set based upon each project's specific and unique operating characteristics. Lowering the eligibility cap would ensure that the Commission's implementation of PURPA is consistent with regulations promulgated by FERC and would protect Oregon's electric utility customers from bearing excessive costs related to QF generation.

Q. Why does Idaho Power seek a reduction in the standard rate eligibility cap?

A. For several reasons, but primarily because of the practice of sophisticated wind QF developers purposefully dividing larger projects, and specifically sizing projects with the purpose of avoiding the more accurate IRP-based negotiated rate contracts, and obtaining a less precise standard rate reserved for small and unsophisticated QFs and developers. Since May 13, 2005, when the Commission adopted the 10 MW eligibility cap for standard contracts, Idaho Power has been faced with a deluge of QF project development, and the pace at which new development is added shows no sign of slowing. Prior to May 13, 2005, Idaho Power had under contract 76 projects with a total nameplate capacity of 317 MW. As of December 31, 2012, Idaho Power has under contract 108 projects (a 42 percent increase), with a total nameplate capacity of 829 MW (a 262 percent increase). A large majority of this QF development has been and continues to be development of intermittent wind

[4] *Re Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at 16-17 (May 13, 2005) ("Order No. 05-584"). A standard contract is a term "used to describe a standard set of rates, terms and conditions that govern a utility's purchase of electrical power from QFs at avoided cost. Standard contracts are made available to a defined class of QFs that are deemed eligible under federal or state law to receive standard rates." Order No. 05-584 at 12.

generation facilities. This influx of largely intermittent QF power is having significant unintended detrimental operational and financial impacts on Idaho Power's system and customers.

Unfortunately for the utilities and their customers, the current 10 MW eligibility cap requires utilities to purchase the vast majority of QF energy through standard avoided cost contracts, which do not account for the actual costs avoided by the utility for the specific resource being purchased. In particular, the standard avoided costs do not account for integration costs, the intermittent nature of the generation, the timing of the generation, or its usefulness for serving load. As a result, utility customers are paying far more for QF power than the cost that is actually avoided by the utility.

Q. What is your understanding of the Commission's rationale in adopting the current 10 MW eligibility cap applicable to all QFs?

A. When the Commission adopted the current 10 MW eligibility cap in 2005, it did so after concluding that the developers of projects 10 MW and under would lack the sophistication and resources to enter into effective negotiations with the interconnecting utility and that the need to negotiate contracts would create a market barrier to QF development. The Commission also reasoned that the risk to customers from the imprecise standard avoided cost rate was acceptable because the size of the small QFs (less than 10 MW) necessarily limited customer exposure to the cost differential between the actual avoided cost rate and the standard rate.

Q. In your opinion, is that rationale still applicable?

A. No. Experience has demonstrated that both of these conclusions are no longer correct. *First*, the developers of today's QF projects, particularly wind projects, are not unsophisticated or lacking in financial resources. On the contrary, the vast majority of today's QF projects are built by developers that have many projects in development, extensive experience negotiating power purchase agreements, and significant corporate backing. *Second*, while the risk to customers posed by the differential between standard rates and the utility's actual avoided cost may be relatively small for individual small QF projects, as utility systems are inundated by multiple large QF projects, the cumulative impact is significant. Thus, customers are bearing significant additional costs in excess of the actual avoided cost rate, in violation of PURPA's mandates.

Q. Is the Company seeking to avoid contracting with wind and solar QFs by seeking a reduction in the standard rate eligibility cap?

A. No. Idaho Power's request is straightforward. The Company is not seeking to terminate its purchase obligations, nor is it seeking to undermine the fundamental purpose of PURPA. An eligibility cap set at 100 kW will continue to provide a standard contract and a standard avoided cost rate to small distributed generation projects that are not equipped with the knowledge or financial strength to negotiate an individual contract with the utility. However, at the same time, an eligibility cap set at 100 kW will ensure that utilities are able to negotiate contracts and avoided cost values with larger projects to ensure that the appropriate avoided cost is calculated based on the project's unique operating characteristics.

Q. Has Idaho Power seen such development of intermittent QF projects in the state of Oregon?

A. While the majority of Idaho Power's QF development has occurred in the state of Idaho, the request here is intended to preempt the negative effect of entering into long-term PURPA contracts at inflated standard rates. Idaho Power's system, customers, and load are divided between Idaho and Oregon roughly 95 percent in Idaho, and 5 percent in Oregon. However, PURPA development is divided roughly into 96 percent in Idaho and 2 percent in Oregon. Additionally, as referenced earlier in my testimony, there have been numerous QF requests for Oregon contracts with Idaho Power that would more than triple the total nameplate capacity of QF generation in Idaho Power's Oregon jurisdiction. Furthermore, the Company, and both the Idaho and Oregon Commissions have already seen several cases where QF projects have attempted to arbitrage the rate differential between Idaho and Oregon's avoided cost rates for Idaho Power with requests to wheel power from Idaho Power's Idaho service territory into its Oregon service territory, with the intent to gain access to a higher avoided cost calculation. Both Commissions have denied the requests of two QFs to establish such contracts. Indeed, Idaho Power has recently received 10 requests for Oregon PURPA contracts totaling 93.2 MW of new PURPA generation. Of these 10 requests, nine are wind QFs representing 90 MW, or 97 percent, of the total nameplate capacity of the proposed projects. Of these 10 requests, seven were received by Idaho Power on January 25 and 26, 2012.[5] These seven projects total 70 MW. It appears from these requests that at least some of the QFs are larger projects that have been disaggregated so as to receive the standard rates.[6]

By addressing the issues raised in this case now, rather than after Oregon is inundated with QFs, the Commission can proactively ensure that Idaho Power's customers are not unreasonably harmed by standard rate contracts that fail to ensure customer indifference to QF generation.

Q. Does FERC require that standard rates be available to QFs up to 10 MW?

[5] These seven wind projects are as follows: Pepper Ridge, Western Desert Energy, Bar MMM Family Trust, Jett Creek Windfarm LLC, Durbin Creek Windfarm, LLC, Benson Creek Windfarm LLC, and Prospecter Windfarm LLC.

[6] For example, there are four 10 MW projects (Jett Creek, Durbin Creek, Benson, Creek, and Prospecter) all being developed near Huntington, Oregon, by the same developer, Oregon Windfarms, LLC. This developer is also responsible for the development of several disaggregated projects in Idaho, although in Idaho, its corporate entity is "Idaho Windfarms, LLC."

A. No. FERC requires standard rates be made available to QFs sized at 100 kW or smaller. PURPA was intended to encourage the development of cogeneration and small power production facilities that meet the requirements to become QFs.[7] To this end, Section 210 of PURPA imposes requirements on utilities, the most far-reaching of which is the requirement that a utility purchase energy and capacity from QFs.[8] PURPA mandates that rates paid to QFs for their energy and capacity must be just and reasonable, not discriminate, *and not exceed the utility's avoided cost*.[9] In setting this standard, FERC intended that utility customers should be neither helped nor harmed by the utility's purchase of QF power and, in fact, should remain "indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[10]

Q. What rationale did FERC put forth for requiring that a standard rate be made available to QFs 100 kW and smaller?

A. FERC stated a concern for the transaction costs for small developers associated with the sale of QF energy and capacity, and adopted regulations requiring the implementation of standard rates for purchases for all QFs with a design capacity of 100 kW or less. In adopting this requirement, FERC noted that "the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rate."[11] However, FERC also noted that if it were to require individually-negotiated rates for QFs less than 100 KW, "the transaction cost

[7] FERC Order No. 69, 45 Fed. Reg. 12,215 (Feb. 25, 1980) ("Order No. 69").

[8] *See generally* 16 U.S.C. §§ 824a-3.

[9] *See* 16 U.S.C. §§ 824a-3(b), (d) (rates for purchases by utilities must be at the avoided cost).

[10] *So. Cal. Ed. Co.*, 71 F.E.R.C. ¶ 61,269, 62,079 (F.E.R.C. 1995).

[11] Order No. 69 at 12,223.

. . . would likely render the program uneconomic for this size of qualifying facility."[12] Consequently, while FERC understood that the standard rate would necessarily prove a less accurate measure of the utility's actual avoided costs, it apparently found that inaccuracy an unavoidable and acceptable consequence of encouraging small QF development. Notably, when determining standard rates, FERC's regulations nonetheless require state commissions to consider, to the extent practicable, other factors set forth in its regulations, such as the availability of QF generation during peak loads, QF dispatchability, QF reliability, and the individual and aggregate value of the QF's energy and capacity to the utility's system.[13]

Q. How has the Commission implemented FERC's requirement to make standard rates available to QFs 100 kW and smaller?

A. Although FERC's rules require standard rates for QFs smaller than 100 kW, the rules also provide that individual state commissions may adopt standard rates for larger QFs "provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases."[14] Pursuant to this authority, the Commission has steadily increased the eligibility cap for Oregon QFs from 100 kW to the current level of 10 MW. Initially, the Commission set the eligibility cap at 100 kW, the minimum level mandated by FERC.[15] Then, in Order No. 91-1383 the Commission increased the cap to 1 MW out of concerns that the transaction costs of negotiating an agreement "could be prohibitive" and therefore harm small QFs.[16]

[12] Order No. 69 at 12,223.

[13] 18 C.F.R. § 292.304(c)(3).

[14] 18 C.F.R. § 292.304(c)(2); Order No. 69 at 12,223.

[15] *See Re Competitive Bidding by Investor-Owned Electric Utility Company's*, Docket UM 316, Order No. 91-1383, 127 P.U.R.4th 306 (Oct. 18, 1991); *Re OAR 860-029-040(5)(a) Relating to Qualifying Facilities*, Docket AR 246, Order No. 91-1605, 1991 WL 537183 (Nov. 26, 1991).

[16] *Id.*

In Docket UM 1129, the Commission again revisited the issue, and after a full contested case hearing, adopted the current 10 MW eligibility cap—over the strong opposition of the utilities.[17] In reviewing the issue, the Commission sought to balance two fundamental policy objectives. In particular, the Commission stated that the eligibility cap must be set at a level that effectively mitigates customer risk caused by the inherent differential between the standard rate and the actual avoided cost rate.[18] At the same time, the Commission found that the eligibility cap must also be set at a level that will mitigate market barriers to QF development.[19] After examining the evidence and arguments, the Commission came to the following conclusions:

With respect to market barriers, the Commission found that for projects smaller than 10 MW, the costs to negotiate a QF contract would represent too great a fraction of total investment costs (which the evidence suggested was approximately $1 million per MW), while for projects above 10 MW, the costs to negotiate a QF contract represented a reasonable fraction of an overall investment.[20] Similarly, the Commission found that while "other market barriers, such as asymmetric information and an unlevel playing field obstruct the negotiation of non-standard QF contracts,"[21] for QFs larger than 10 MW, "improved negotiation parameters and guidelines [subsequently adopted in Order No. 07-360] and greater transparency in the negotiation process" will overcome these "other market

[17] Order No. 05-584 at 16-17.
[18] *Id.* at 16.
[19] *Id.* at 16.
[20] *Id.* at 17.
[21] *Id.* at 16-17.

barriers."[22] Based on these findings, the Commission adopted the recommendation of Staff and Oregon Department of Energy ("ODOE") to raise the standard contract eligibility cap to 10 MW.[23]

With respect to the risk posed to customers by the differential between standard rates and avoided costs, the Commission made no specific findings. However, it is worth noting that the testimony relied on by the Commission *anticipated minimal wind penetration.* Indeed, ODOE testified that a total of 50 MW of wind development across the service territory of both PGE and PacifiCorp "would be an aggressive goal in the next five years or so."[24]

Q. What has QF development been like for Idaho Power since the Commission raised the standard rate eligibility cap to 10MW with Order No. 05-584?

A. Since 2005, Idaho Power has been inundated with QF projects. As noted above, Idaho Power currently has over 829 MW of QF projects under contract and is aware of at least 340 MW of additional wind QF projects, plus 200 MW of other QF resources that may be requesting QF agreements. Assuming that these QFs are developed, in the near future, Idaho Power may have over 1,400 MW of QF projects under contract.[25] Of the 829 MW of QF projects under contract, 68 percent of the capacity has been developed since 2005. And with respect to QF projects, wind development has eclipsed all others. Indeed, when considering only those QFs that are either in operation or under contract, wind constitutes 70 percent of QF nameplate capacity. In contrast, as of 2005, wind represented only 44 percent of Idaho Power's QF capacity. Moreover, if the currently known QF wind projects are

[22] *Id.* at 17.

[23] Order No. 05-584 at 17.

[24] UM 1129, ODOE/Exhibit No. 2, DeWinkel/Page 5, ll. 13-14.

[25] Attached to this testimony as Exhibit 201 is a summary of all Idaho Power's QFs.

developed, the QF wind nameplate capacity of over 1,000 MW may surpass Idaho Power's minimum loads.

For Idaho Power, the financial impact of QF development is also substantial. In 2004, Idaho Power's power supply expense related to PURPA projects was $40 million annually. In 2009, this annual expense reached $60 million. By 2012 the expense will reach $117 million—nearly double the expense just three years prior. By 2014, Idaho Power expects that all PURPA projects currently operating on Idaho Power's system, all PURPA projects currently under construction, and all PURPA projects with Idaho Commission-approved contracts will be on-line and fully operational. The associated annual power supply expense attributable to only these PURPA projects will be $140 million—an amount that increases to $146 million in 2026. These numbers reflect only those PURPA projects known at this time and do not account for PURPA projects developed between now and 2026. Indeed, as of today, Idaho Power's estimated contractual commitment related to PURPA projects Idaho Power already has under contract equals more than *$4.1 billion*, which exceeds Idaho Power's total rate base utilized to serve a 24,000 square mile service territory.

Q. How is it that standard rates are a less accurate approximation of a utility's avoided cost, as you stated above?

A. Both FERC and the Commission have recognized that standard rates are an approximation of a utility's actual avoided costs because the standard rate does not take into account the QF's specific project characteristics.[26] For example, standard rates do not consider costs imposed on the utility by the need to integrate QF wind, the fact that QF energy is not dispatchable, or the fact that QF energy and capacity

[26] *See* Order No. 05-584 at 16; Order No. 69 at 12,223.

must be purchased regardless of the utility's capacity or energy needs. None of these costs are insignificant and under the current standard rate methodology, they are borne exclusively by customers.

For instance, standard QF contracts require Idaho Power to take all energy the QF project delivers at any time of the year or day, at a specified price. As a result, it is not unusual for Idaho Power to be required to back down less expensive generation resources to accommodate the QF deliveries; alternately, the QF generation must be sold into the market, which can occur at a loss if the standard rate is greater than market prices at the time of the sale. Both of these options result in additional costs that are passed on to customers.

Moreover, standard rates do not consider the dispatch capability (or lack thereof) of a QF resource. For Idaho Power, this is a particular concern because the methodology used to calculate its standard rates uses a natural gas-fired CCCT as the proxy resource avoided by the purchase of the QF's output. However, if Idaho Power owned and operated a CCCT, it would operate the plant only when economic to do so. If market prices were less than the cost to operate the CCCT, Idaho Power would look to the market for energy purchases, and the CCCT would be run only when Idaho Power's load required. These facts are not captured in the existing methodology used to calculate standard rates, which assumes that Idaho Power would operate the CCCT whenever the QF is generating, regardless of contemporaneous market prices or existing load.

Finally, the aggregate impact of QFs on the utility's system is also not accounted for in the standard rates. The cumulative impact is of particular concern for Idaho Power given the amount of QF energy it is currently facing, and the failure to account for this impact in the avoided cost rate is contrary to FERC regulations. FERC regulations direct state commissions to consider in their calculation of the avoided cost rates, to the extent practicable, the aggregate value of the energy and capacity from all QFs on the utility's system. In Order No. 69, FERC found that small, dispersed QFs may provide, in total, an amount of capacity sufficient to allow the utility to offset other purchases.[27] In other words, even if the energy and capacity from one QF does not, when considered in isolation, allow the utility to avoid a particular cost, FERC directed state commissions to consider the impact to a utility's system of all QFs when calculating the standard rates for purchases. FERC correctly concluded that the cumulative impact of all QFs may allow a utility to defer an investment that any one individual QF would not.

In this case, for Idaho Power specifically, the opposite is occurring—the aggregate impact of all QFs, especially intermittent QFs, on Idaho Power's system is not allowing Idaho Power to avoid costs; rather, it is causing Idaho Power to incur costs that are not reflected in the standard rates. This flaw can be corrected, however, by lowering the eligibility cap to require individualized avoided costs that consider the total impact of the dramatic influx of QFs on Idaho Power's system.

Idaho Power's requested relief, lowering the eligibility cap, will ensure that the avoided cost rate paid by the Company and its customers is specifically tailored to the QF's unique operational characteristics. This will result in a more accurate avoided cost rate because the rate will specifically consider the individual QF's availability, lack of dispatch capability, reliability, and the usefulness of the QF's energy and capacity during system emergencies. These factors are all specifically identified by FERC as factors that state regulatory commissions must take into account, to the extent practicable, when determining the avoided cost of a utility.[28]

[27] Order No. 69 at 12,224.

[28] *See* 18 C.F.R. § 292.304(e).

Because it is now practicable to consider these factors, the Commission should do so.

Q. You had previously mentioned the Commission's rationale when changing the standard rate eligibility to 10 MW was no longer applicable. Could you explain?

A. Yes. When adopting the 10 MW eligibility cap in Order No. 05-584, the Commission was attempting to strike a balance between reducing market barriers to QF development and the "goal of ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy."[29] The Commission recognized that standard contracts ignore costs associated with unique project characteristics, but reasoned that the relatively small size of the QFs entitled to standard rates rendered the risk to customers acceptable. However, the assumptions on which the Commission based its risk analysis have not proved valid and therefore it is appropriate for the Commission to reconsider its previous decision.

Q. How has it proven to not be valid?

A. In adopting the 10 MW cap, the Commission relied heavily on testimony provided by ODOE[30]—which analyzed the risk associated with the cost differential between the actual and standard rates for wind (based on the standard rates not including an integration component) as follows:[31] ODOE started by assuming a total of 50 MW of wind divided equally across the service territories of PGE and PacifiCorp.[32] Using this example, and assuming a wind integration charge of $3 per MWh, ODOE concluded that the rate impact caused by the differential between the standard rate

[29] Order No. 05-584 at 16.

[30] *Id.* at 17.

[31] UM 1129, ODOE/Exhibit No. 2, DeWinkel/Page 5.

[32] UM 1129, ODOE/Exhibit No. 2, DeWinkel/Page 5, ll. 13-14.

and the actual avoided cost is "de minimus." Time and experience have proved ODOE wrong.

First, wind development has dramatically exceeded ODOE's expectations. As discussed above, Idaho Power currently has nearly 577 MW of QF wind either in operation or under contract (with an additional 101 MW of non-QF wind). In just the last year alone, Idaho Power has received additional requests and inquiries for 90 MW of new Oregon QF wind standard contracts. If ODOE's analysis is updated for Idaho Power's actual wind penetration only (ignoring all other costs), the annual cost impact is $5.5 million.[33] In other words, $5.5 million in actual costs incurred by the utility will not be accounted for in the avoided cost rate. This $5.5 million cost will be paid by customers and is anything but "de minimus."

Second, ODOE's analysis examined only one source of cost differential—wind integration costs. Because ODOE assumed such minimal wind penetration, it never even contemplated the total system impacts of nearly 700 MW of wind on a utility's system, as Idaho Power will soon experience. And the wind integration charge assumed by ODOE is dramatically less than the actual cost incurred to integrate wind, as shown in Idaho Power's latest wind integration study. Idaho Power's current study indicates that wind integration expenses are over $8 per MWh for approximately 800 MW of wind. Updating ODOE's analysis for both Idaho Power's actual wind penetration and its current wind integration charge of $6.50 per MWh results in an annual increase in costs of nearly $12 million—a cost that is paid by customers, not QFs. Importantly, these figures are based only on the wind integration charge and do not take into account the timing of the wind generation or

[33] This assumes 691.92 MW of wind. Using ODOE's 0.30 capacity factor, this results in approximately 208 aMW or 1,822,080 MWh per year. At a wind integration charge of $3/MWh, this translates to a rate impact of $5.5 million per year.

any of the other negative characteristics of intermittent generators. Thus, the Commission's risk assessment relied on two flawed assumptions—minimal wind penetration and a minimal integration cost. Because neither of these assumptions proved accurate, the Commission should reevaluate the balance struck in UM 1129.

Q. Do market barriers exist today that would continue to justify a 10 MW eligibility cap?

A. No. In Order No. 05-584, the Commission supported its decision to increase the eligibility cap from 1 MW to 10 MW with two key factual findings. *First*, the Commission found that the market barrier caused by transactional costs could be mitigated with a 10 MW cap because for projects larger than 10 MW, the "costs of negotiation become a reasonable fraction of total [$10 million] investments costs."[34] *Second*, the Commission found that market barriers other than transactional costs were also an impediment to QF development that could be mitigated by increasing the standard contract eligibility cap. Neither of these rationales applies today.

Q. Can you explain?

A. Yes. As an initial matter, the great majority of QFs today are sophisticated, and in many cases large, multi-national entities that are in the profession of developing power generation. In UM 1129, ODOE's testimony in support of the 10 MW cap appears to have been significantly influenced by its experience with community and locally owned wind energy development,[35] leading ODOE to assume that the QFs for which it was crafting policies would be primarily "community wind projects and small wind farms owned by one or more farmers."[36] This assumption has proven to be

[34] Order No. 05-584 at 17.

[35] UM 1129, ODOE/Exhibit No. 2, DeWinkel/Page 6, ll. 13-14.

[36] UM 1129, ODOE/Exhibit No. 2, DeWinkel/Page 7, ll. 4-6.

incorrect. On the contrary, experience has shown that as a group, QF developers are highly sophisticated, have access to contract experts, possess sufficient financial resources to negotiate a QF contract, and are willing and able to disaggregate large projects specifically to obtain standard rates.[37] For example, Exergy Development Group ("Exergy") is responsible for the development of 19 different QF wind projects interconnected to Idaho Power's system, totaling 321.72 MW.[38] According to its website, Exergy is a large-scale developer of renewable energy projects and is responsible for commercial-scale wind energy development.[39] As is typical of Idaho Power's experience, Exergy's QF projects are in no way isolated developments. Indeed, 11 of Exergy's QF projects[40] are together described as one $500 million development called "Idaho Wind Partners," which is touted as "Idaho's largest wind power project."[41] This development was disaggregated so that each individual project was eligible for Idaho Power's standard rate in Idaho.[42] According to a press

[37] In Idaho, the Company has seen that virtually all of the wind developers seeking standard rates are developers of large projects that disaggregated in order to obtain standard rates. Although these projects are greater than the 10 MW cap currently in place in Oregon, they are frequently at or near the previous 10 aMW cap in Idaho. This fact demonstrates that these developers size their projects at the maximum capacity to allow access to standard rates, even if that means disaggregating a much larger development. Based on the current requests for standard contracts in Oregon and the Company's experience in Idaho, the Company believes that QF developers here will likewise disaggregate in order to receive standard rates in Oregon.

[38] These projects are as follows: Burley Butte, Camp Reed, Fossil Gulch, Golden Valley, Horseshoe Bend, Oregon Trail, Thousand Springs, Tuana Gulch, Milner Dam, Payne's Ferry, Pilgrim Station, Salmon Falls, Yahoo Creek, Cottonwood Park, Deep Creek, Lava Beds, Notch Butte, Rogerson Flats, and Salmon Creek.

[39] http://www.exergydevelopment.com/who-we-are/organization.

[40] Burley Butte, Camp Reed, Golden Valley, Oregon Trail, Thousand Springs, Tuana Gulch, Milner Dam, Payne's Ferry, Pilgrim Station, Salmon Falls, and Yahoo Creek.

[41] http://www.geenergyfinancialservices.com/fact_sheets/Project%20Fact%20Sheet.pdf and http://www.exergydevelopment.com/docs/press-releases/2011/04/06/2010-06-29-ge-unit-invests-in-183-mw-idaho-wind-power-portfolio-states-largest-wind-deal-to-bring-jobs-clean-energy-to-idaho.pdf.

[42] http://www.geenergyfinancialservices.com/fact_sheets/Project%20Fact%20Sheet.pdf.

release issued by GE Energy Financial Services (a unit of General Electric and an investor in the project), "Exergy is one of the major independent renewable energy developers in the USA . . . . The Company has assembled a renewables projects queue of over 4,000 MW across the Western and Midwestern United States."[43]

Another developer of five separate previously-proposed PURPA projects in Idaho is Cotterel Wind Energy Center, LLC, a Houston-based company that is developing the project for Shell Oil, the project's owner.[44] A press release issued by the Idaho Commission summarizes this development as follows:

> The five projects submitted by Cotterel Wind Energy Center LLC and owned by Shell, initially responded to a 2009 Idaho Power bid request as one large project of 150 MW. After an agreement was not reached, Cotterel submitted five PURPA contracts requesting the published avoided-cost rate for five 10-aMW projects with a scheduled online date of Oct. 31, 2014.[45]

Four Idaho Power wind QFs were developed by a subsidiary of farm equipment giant John Deere.[46] Another six wind farms are now owned by Terna Energy Overseas Limited, a Cyprus company that acquired 10 wind farms in March, 2011.[47] These wind farms were developed by Idaho Wind LLC, a subsidiary of PowerWorks, which is itself an affiliate of Pacific Winds.[48] PowerWorks boasts on its

---

[43] http://www.exergydevelopment.com/docs/press-releases/2011/04/06/2010-06-29-ge-unit-invests-in-183-mw-idaho-wind-power-portfolio-states-largest-wind-deal-to-bring-jobs-clean-energy-to-idaho.pdf.

[44] The contracts for these five projects were rejected by the Idaho Commission after determining that they were not finalized before the eligibility cap for standard rates was reduced to 100 kW. The Company believes that these projects will seek to negotiate an avoided cost rate but those negotiations have yet to begin.

[45] http://www.puc.idaho.gov/internet/press/072711_Allwinddenials.htm.

[46] The projects are Bennett Creek, Cassia, Hot Springs, and Tuana Springs.

[47] http://investing.businessweek.com/research/stocks/private/snapshot.asp?privcapId=129266660. The wind farms are Cold Springs, Two Ponds, Ryegrass, Mainline, Desert Meadow, and Sawtooth.

[48] http://www.powerworks.com/aboutus.aspx; http://cleantechnica.com/2011/01/03/san-francisco-wind-developer-sells-power-to-idaho-utility.

website that it is currently developing 18 projects in 12 states, totaling over 1,500 MW. When describing itself, PowerWorks states that "Our principals and engineering staff has extensive experience during the last 14 years with numerous wind and solar projects, involving development, permitting, engineering, design, *power marketing*, finance, construction, equipment procurement, and installation, and operation and maintenance."[49]

The Rockland Wind QF project was developed by a company called Ridgeline Energy. That company's website states that Ridgeline is now a subsidiary of Atlantic Power Corporation and has "developed a portfolio of sites representing more than 1,000 MW of potential capacity."[50] The website continues by stating, "Backed by Atlantic Power, Ridgeline has the development capital and financial support to acquire existing renewable energy projects and to develop, construct and operate new projects."[51]

Examining Idaho Power's PURPA contracts demonstrates that of the 27 total wind QFs currently either on-line or under contract, only one QF, developed by Joseph Millworks, Inc., was not developed by a sophisticated renewable energy development company with years of experience developing renewable projects. And that one QF has a total capacity of 3 MW, or approximately 0.4 percent of Idaho Power's total QF wind capacity.

It does not follow that these developers, who collectively are responsible for 26 of Idaho Power's current 27 contracts for QF wind,[52] lack either the sophistication

[49] http://www.powerworks.com/aboutus.aspx (emphasis added).

[50] http://www.atlanticpower.com/affiliates/ridgeline-energy.aspx.

[51] http://www.atlanticpower.com/affiliates/ridgeline-energy.aspx.

[52] If one includes in this calculation the wind QFs that were disallowed by the Idaho Commission, the total number of contracts increases to 40.

or financial resources to negotiate with Idaho Power. The Commission's rationale for adopting a 10 MW eligibility cap was to "eliminate negotiations for QF projects for which they would be *economically prohibitive*."[53] For these developers, who are overwhelmingly the developers of wind QFs in Idaho Power's service territory, negotiating an individualized PURPA contract is well within their means.

Moreover, the Commission's conclusion in Order No. 05-584 assumes that one developer is constructing one QF as an individual, isolated development. The transactional costs, therefore, must be viewed in isolation and compared to the development costs of that single QF. Idaho Power's experience does not support this assumption. Indeed, the vast majority—all but three—of Idaho Power's wind QFs were constructed by a developer that was also more or less simultaneously developing several other QFs.[54] As an example, Exergy has developed 11 wind QFs as part of one $500 million development. To examine each of these 11 QFs individually to determine if the transactional costs are economically prohibitive is therefore the wrong analysis. Rather, the Commission must examine whether the transactional costs associated with negotiating a QF contract are economically prohibitive for a $500 million project. It is difficult to persuasively argue that if Exergy was required to negotiate a QF contract for each of its 11 projects, the costs of doing so would be economically prohibitive when the total investment is $500 million.

[53] Order No. 05-584 at 40 (emphasis added).

[54] Idaho does not have a dissaggregation rule similar to Oregon's. Therefore, it is arguably easier for QF developers in Idaho to chop up a 100 MW project into smaller sizes to take advantage of standard avoided cost rates. However, a not insignificant advantage of Idaho Power's request here is that if the eligibility cap is lowered, disaggregation will cease to be a problem.

In light of the actual QF development that has occurred since the Commission issued Order No. 05-584, and the scale of these developments, the Commission's assumptions regarding transactional costs simply no longer apply.

Q. Do the Commission's Negotiation Guidelines work to mitigate the "other" market barriers that the Commission referred to in its rationale to raise the eligibility cap to 10 MW?

A. Yes. With respect to other market barriers, the Commission recognized that QFs of all sizes face asymmetrical access to information and an unlevel playing field. The Commission concluded, however, that for QFs greater than 10 MW, these barriers could be sufficiently mitigated through the adoption of the large QF guidelines in Order No. 07-360.[55] It follows that if those guidelines are applied to all QFs larger than 100 kW, the market barriers for those smaller QFs could be mitigated as well. For instance, for Idaho Power the negotiation guidelines require the use of the IRP methodology to determine the avoided cost rate to begin negotiations. This transparency ensures that QFs know exactly how the avoided cost rate is calculated when negotiations begin. And because these developers are so large and sophisticated, these market barriers, like transaction costs, are not as significant an impediment as the Commission assumed in Order No. 05-584.

Idaho Power's experience negotiating contracts in Idaho also suggests that such negotiation is not necessarily a market barrier. Historically, Idaho Power has negotiated six PURPA contracts totaling 200.9 MW of capacity.[56] Two of these contracts were negotiated since the eligibility cap was lowered in Idaho. Idaho

[55] *See* Order No. 05-584 at 17. The Commission concluded that market barriers for QFs greater than 10 MW "will be best overcome for those QFs by improved negotiation parameters and guidelines and greater transparency in the negotiation process."

[56] By way of comparison, the Company has executed a total of 61 contracts; approximately 1 in 10 PURPA contracts were negotiated.

Power negotiated and submitted to the Idaho Commission for approval a negotiated contract for the 40 MW High Mesa wind project.[57] Idaho Power also negotiated a contract for a 20 MW solar QF called Murphy Flats, which was approved by the Idaho Commission on October 20, 2011.[58] These negotiations occurred after Idaho had lowered the standard rate eligibility cap to 100 kW for wind and solar QFs, and without comparable guidelines to those that govern the Oregon negotiation process.

Q. Has the concern regarding the proportional transaction costs to the costs of development materialized?

A. No. Transactional costs have decreased as a fraction of overall investment costs. With respect to transactional costs, the Commission relied in particular on evidence presented by ODOE demonstrating that "10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs."[59] This conclusion assumed that a 10 MW project costs approximately $10 million to develop.[60] In essence, the Commission found that the eligibility cap should be set at the level commensurate with a $10 million investment because at that level the transaction costs are a "reasonable fraction of total investment costs."

Today, experience has demonstrated that wind developments cost substantially more than the Commission found in Order No. 05-584 and therefore transactional costs are an even smaller fraction of the total investment. In Order No. 05-584, the record demonstrated that it cost approximately $1 million per MW to

[57] The case number for the Idaho Commission docket is IPC-E-11-26.

[58] The case number for the Idaho Commission docket is IPC-E-11-10 and the Idaho Commission order is Order No. 32384.

[59] Order No. 05-584 at 17.

[60] Order No. 05-584 at 14 ("at 10 MW, negotiation costs become a relatively small fraction of total $10 million investment costs.").

develop a QF.[61] While development costs are not readily available, according to a newspaper article, the 3 MW Lime Wind QF in Oregon cost $7 million to develop, or approximately $2.33 million per MW.[62] While larger projects benefit from economies of scale, publicly available evidence suggests that even for these larger wind projects, the cost per MW is comparable. As discussed in more detail above, the "Idaho Wind Partners" development, a recent 183 MW wind project in Idaho, cost approximately $500 million, or $2.73 million per MW.[63] Based on these numbers, it is unlikely that a 10 MW wind project could be developed today for $10 million. Rather, such a project would likely cost closer to two to three times that amount. Thus, negotiation costs are now an even smaller fraction of the total $20 to $30 million investment costs—meaning transaction costs are an even smaller market barrier. In other words, as development costs increase (as they have done), the Commission's reasoning supports a reduction in the eligibility cap because negotiation costs become an even smaller percentage of the overall investment.

Q. Is there a concern with regulatory, or jurisdictional, arbitrage regarding the standard rate eligibility cap?

A. Yes, for Idaho Power, lowering the eligibility cap for wind and solar QFs will prevent regulatory arbitrage across its Idaho and Oregon jurisdictions. The Commission should lower the eligibility cap for Idaho Power to allow for consistency between the Company's Oregon and Idaho service territory, and to thus discourage regulatory

[61] Order No. 05-584 at 13 ("PacifiCorp also observes that a 3 MW QF project requires approximately $3 million in capital costs to construct . . .). Order No. 05-584 at 14 ("ODOE represents that at 10 MW, the negotiation costs become a relatively small fraction of total $10 million investment costs.").

[62] http://www.bakercityherald.com/Local-News/Baker-County-s-first-wind-farm-scheduled-to-open-in-November.

[63] http://www.geenergyfinancialservices.com/fact_sheets/Project%20Fact%20Sheet.pdf.

arbitrage. Indeed, two QFs—Western Desert Energy, LLC, and Tumbleweed Energy II, LLC—have already sought to take advantage of the current difference between the Idaho and Oregon standard rates and eligibility cap by attempting to force Idaho Power to accept delivery of the QF's power in Idaho and then wheel the power to an undisclosed place in Oregon where Idaho Power would then "purchase" the power at the Oregon standard rates.[64] Additionally, another non-wind QF—Kootenai Electric Cooperative, Inc.—has also filed a complaint with the Commission seeking Oregon rates rather than Idaho rates for a generation project physically located in the state of Idaho.[65] These attempts to game the system are clear, unapologetic, and emblematic of what is likely to continue to occur as QF developers retain counsel and file complaints seeking Commission approval of their proposed transactions (transactions Idaho Power maintains are blatant violations of PURPA).

For all of the reasons stated above, Idaho Power requests that the Commission reduce the standard contract eligibility cap to 100 kW for all wind and solar QFs. Granting this relief will ensure that Oregon customers are not subsidizing QF development in violation of PURPA and Oregon law.

V. UPDATES OF AVOIDED COST RATES

Q. How frequently are avoided cost rates currently updated?

A. Updates to avoided cost rates are currently aligned with the acknowledgement of the IRP, for both the Oregon Method and the IRP methodology. Within 30 days of an IRP being acknowledged, Idaho Power must file an update to standard rates. The IRP methodology is also updated at the same time as Idaho Power begins using the

[64] *See* Dockets UM 1552 and 1553.

[65] *See* Docket UM 1572.

IRP AURORA model setup and inputs to calculate avoided cost rates for negotiated contracts.

Q. How frequently do you believe the Oregon Method standard avoided cost rates should be updated?

A. As I stated previously in my testimony, Idaho Power would like to maintain consistency in avoided cost rates between the Company's Idaho and Oregon service areas. As implemented in Idaho, I am proposing that Idaho Power's standard avoided cost rates be updated annually in conjunction with the release of the EIA natural gas price forecast. The natural gas price forecast has a substantial influence on the avoided cost rates calculated under the Oregon Method, and the historical volatility in natural gas prices dictate that more frequent updates are necessary to properly align avoided cost rates.

Q. How frequently do you believe the inputs used for the IRP methodology should be updated?

A. Like the Oregon Method, natural gas prices have a substantial impact on avoided cost rates calculated with the IRP methodology. In addition, the utility's load forecast influences the results of the AURORA simulation. Because of this, I believe the gas price forecast and the load forecast used in the AURORA model should be updated annually.

VI. WIND INTEGRATION COSTS

Q. Can you explain why there is a cost associated with integrating wind generation on an electrical system?

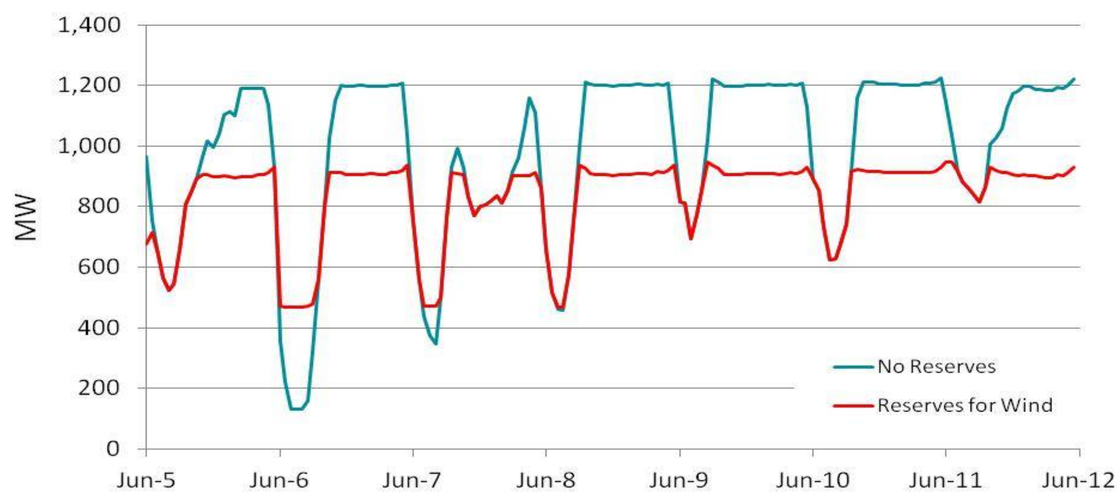
A. Yes, I can. Due to the variable and intermittent nature of wind generation, an electrical system operator has to provide additional operating reserves from other dispatchable resources that are capable of increasing or decreasing generation on short notice to offset changes in wind generation. The effect of having to hold additional operating reserves on other dispatchable resources is that the operation of those resources is restricted and they cannot be economically dispatched to their fullest capability. This results in higher power supply costs that are subsequently passed on to customers.

Q. Are hydroelectric generators good resources to use to integrate wind?

A. Yes. Operationally, the quick response capabilities of a hydro unit make them ideal for responding to changes in wind generation. However, many people believe that because operationally hydro resources are good resources for integrating wind, the cost of using them for this purpose should be low, and this is not the case. The flexibility and quick response characteristics hydro units provide, especially when coupled with a storage reservoir that can be used for shaping generation over longer time periods, provides considerable operational value as well as economic value when water can be stored or shaped so that it is used to produce electricity at times when it is the most valuable.

Figure 1 below from Idaho Power's latest wind integration study shows this impact on hydro generation at Idaho Power's Hells Canyon Complex during a typical week in June. The teal line represents how the generators would be operated if additional operating reserves were not necessary due to wind generation on the system. In comparison, the red line shows how the range of generation is limited both upwards and downwards in order to provide reserves for intermittent wind resources. The result is less water can be run, and electricity generated, during heavy load hours when it is more valuable.

Figure 1 – Impact of Wind Generation on Hydroelectric Generators



Q. Are natural gas and coal units used to integrate wind?

A. Yes, they are. However, they are not able to respond as quickly as hydro units. Natural gas units can respond to changes in wind generation, but they have to be operating to do so. Because natural gas CCCT units are typically on the margin relative to market prices, there are times when they do not operate. SCCT units are typically operated as "peaker" plants due to their lower efficiency/higher heat rate, and operate much less frequently than CCCTs. The cost of using natural gas resources to integrate wind increases substantially when the electrical system operator has to operate natural gas units for the sole purpose of providing operating reserves, at times when the gas unit would otherwise not be dispatched due to economics.

Coal units can also be used to integrate wind; however, operationally they are not able to rapidly change generation output. Therefore, generation from coal units will typically be used last and only if a sizeable adjustment in total generation is needed to account for changes in wind generation.

Q. Is there a specific method that can be used to calculate the cost of wind integration?

A. No, I do not believe it is possible to detail a "specific" method because of differences in electrical systems and the available analysis tools. However, I think in general principle the concept that has been used by various utilities is the same—comparing the cost of operating the electrical system both with and without intermittent wind generation on the system. In addition, while many utilities have done wind integration studies, not all utilities use the same computer model when modeling their electrical system. Therefore, it would be difficult to define a specific method due to potential limitations on the capabilities of each model.

Q. Is the cost of integrating wind considered in Idaho Power's IRP when comparing the costs of utility-owned generation resources?

A. Yes, it is. The cost of integrating wind is incurred regardless of whether the wind resource is utility-owned or contracted through a third party, and ultimately increases power supply costs that are passed on to customers. It would be inappropriate to ignore these costs when evaluating new resources types in the IRP.

Q. Should the cost of integrating wind be accounted for when calculating avoided cost rates under PURPA?

A. Yes, I believe they should. Wind integration costs are real, and Idaho Power accounts for them in the IRP process when comparing the cost of wind generation against other resource types. Ignoring wind integration costs when calculating avoided cost rates simply pushes the additional cost on to customers.

Q. Is the cost of integrating wind generation the same for anyone operating an electrical system?

A. No, it is not. As I explained previously, the costs associated with wind integration are specific and unique for each individual electrical system based on the amount of wind being integrated and the other types of resources that are used to provide the necessary operating reserves. In general terms, the cost of integrating wind increases as the amount of nameplate wind generation on the electrical system increases.

Q. What were the results of Idaho Power's first wind integration study?

A. Idaho Power completed its initial wind integration study and published the study report and a subsequent addendum in 2007. The results of the study indicated that at approximately 500 MW of nameplate wind, there was an associated integration cost of $7.92/MWh. The other Idaho investor-owned utilities, Avista Corporation and Rocky Mountain Power, completed wind integration studies at approximately the same time and each utility filed a petition with the Idaho Commission asking to reduce avoided cost rates for wind projects based on the results. Although the Idaho Commission did not combine the three utility petitions into a single case, all three were processed simultaneously (Idaho Commission Case Nos. IPC-E-07-03, AVU-E-07-02, and PAC-E-07-07).

Q. What was the final outcome of these cases?

A. A joint settlement stipulation was ultimately approved by the Idaho Commission in 2008 (Idaho Commission Order No. 30488 for Idaho Power). The settlement stipulation established a tiered integration cost structure that increased as nameplate wind generation increased. The stipulation also established a cap of $6.50/MWh with the understanding that each of the utilities would update their integration studies in the future as more wind generation was added.

Q. Has Idaho Power updated its initial wind integration study?

A. Yes. Idaho Power has conducted a new wind integration study based upon current information. That study is attached hereto as Exhibit 205. Idaho Power will also file this wind integration study later this month with its IRP update filing.

Q. Based on the results of Idaho Power's latest wind integration study, what is the cost of integrating wind generation on Idaho Power's electrical system?

A. Idaho Power's latest wind integration study analyzed three different levels of wind penetration: 800 MW; 1,000 MW; and 1,200 MW. The results of the analysis showed integration costs of $8.06/MWh, $13.06/MWh, and $19.01/MWh, respectively.

Q. How much wind generation does Idaho Power currently have on its system?

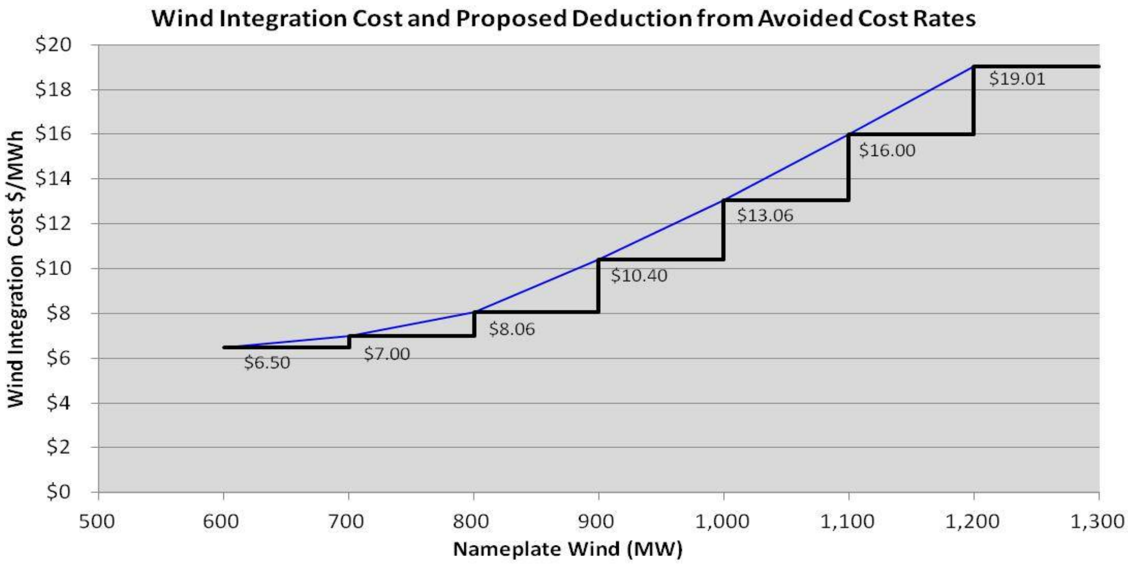
A. Idaho Power currently has 577 MW of PURPA wind and an additional 101 MW from the Elkhorn Valley Wind Farm, for a total of 678 MW.

Q. If the cost of integrating wind is different for each electrical system operator, how do you propose to account for these costs in avoided cost rates?

A. I believe the most efficient way to account for wind integration costs would be for each utility to have a schedule that identified an amount to be deducted from avoided cost rates based on the nameplate capacity of installed wind generation. Being schedule-based would recognize there is a difference in cost between each utility and it would allow wind integration costs to be updated for each utility as additional wind generation is added.

For Idaho Power, Figure 2 below represents the methodology the Company is proposing which incorporates the latest study results. Under Idaho Power's proposal, the current deduction of $6.50/MWh would be used until total nameplate wind generation reached 700 MW. Once 700 MW is reached, the wind integration charge would be increased to $7.00/MWh. As shown in Figure 2, subsequent increases would occur as each incremental 100 MW of wind generation is added.

Figure 2 – Integration Cost and Proposed Deduction from Avoided Cost Rates



Idaho Power asks that the Commission authorize a wind integration charge as shown above in Figure 2 and that a separate Schedule be established and maintained for this charge.

VII. CONTRACT TERM, FIXED PRICE PORTION, LEVELIZED RATES, ETC.

Q. Does Idaho Power have a proposal regarding the appropriate maximum contract term for a QF power sales agreement?

A. Yes. Idaho Power proposes that the Commission continue to authorize contracts up to a 20-year term. Idaho Power is required to contract up to a 20-year term in its Idaho jurisdiction, and proposes that the Commission keep the term for Oregon contracts the same. However, Idaho Power maintains that a 20-year QF contract containing fixed avoided cost prices unfairly shifts the market energy price risk from the QF to Idaho Power's customers. Requiring Idaho Power to enter into 20-year QF contracts containing fixed avoided cost prices provides the QF developer a guaranteed avoided cost rate for energy delivered to Idaho Power regardless of what the actual market prices of energy are during those 20 years. And the difference between the QF fixed avoided cost rates and the market rates are passed on to Idaho Power's customers. Historically, this difference has proven to be one-sided, to the detriment of Idaho Power's customers.

Q. Has the Commission previously addressed the issue of contract term?

A. Yes, Commission Order 05-584, on page 17 discusses this issue and follows with a resolution that the standard contract term is established to be up to 20 contract years, but that only the first 15 years are eligible for fixed avoided cost prices and avoided cost prices beyond 15 contract years will be one of the market pricing options, at the election of the QF.

Q. What does Idaho Power propose with regard to the fixed price portion of the 20-year contract term?

A. The Commission in its ruling in Order 05-584 established a 20-year contract term and fixed avoided cost prices for only the first 15 contract years. This ruling effectively provided the QF industry the certainty of a 20-year contract and provided partial protection to the Idaho Power customers of not paying excessive avoided costs by allowing only 15 years to be at fixed avoided cost prices. Idaho Power proposes that the fixed price portion of a QF contract be reduced to 10 years, to more evenly distribute and allocate the market risk and hedge that the QF receives with a long-term fixed rate against market prices or other alternatives. This would help to better allocate, and possibly mitigate the market risk that is almost entirely borne by customers.

Q. Does Idaho Power agree that a levelized rate option should be provided for in QF contracts?

A. No, for similar reasons as stated above. A key element of the levelized rate concept is that a QF project is paid a flat avoided cost (levelized rate) for the full term of the contract. This levelized rate is a calculation based upon the various annual predicted avoided cost rates that would be paid for energy for each year during the term of the contract. This levelized calculation results in the QF project receiving energy rates in the early years of the QF contract that are higher than the actual avoided costs of energy and then in the later years of the QF contract, the levelized rates are lower than the actual avoided costs in those years. By allowing the QF project to use this leveled pricing concept, Idaho Power's customers are essentially loaning the QF money in the early years of the contract with the expectation that the QF project will pay back the customer loan in the back half of the contract by continuing to generate and be paid a value (levelized rate) that is lower than the avoided cost in those years.

Q. Does Idaho Power have any QF agreements that contain levelized rates?

A. Yes, the Company has approximately 60 contracts that contain levelized rates.

Q. What has Idaho Power's experience been with levelized rate QF agreements?

A. Recently a 10 MW QF project that contained levelized rates defaulted on their long-term QF agreement prior to the full term of the agreement. Due to the fact that the project failed to perform for the full term of the agreement, customers were not able to recoup the early year overpayments. The QF agreement did contain a Liquidated Damages provision that specified the amount of damages owed to Idaho Power customers from the QF project in order to repay this overpayment, or loan, in the event the project did not perform the full term of the agreement. These damages amounted to over $10 million. The project refused to pay the damages, and after years of costly negotiation and litigation, Idaho Power will likely only recover a minimal portion, if any, of the damages owed. Indeed, this particular QF, like nearly all QF projects, is developed following a business model whereby a special purpose entity with essentially no assets except the power purchase agreement are owned by the contracting entity; thus, there are very minimal, if any, assets available for Idaho

Power to collect upon, which results in only a small fraction of the judgment amount being collected, and only a small fraction of Idaho Power's customers' overpayment being recouped.

Q. Are there any other levelized rate QF contract experiences you would care to explain?

A. Yes, Idaho Power had a very similar experience with two small QF projects in 1999. In that case, again the projects defaulted and the contracts were terminated early, liquidated damages of approximately $100,000 were calculated due to the early termination of the QF contracts that contained levelized rates. The projects refused to pay and the final outcome of the proceedings was that Idaho Power was able to collect less than $20 in scrap value from the project.

Q. Does Idaho Power have any problems with the QF projects that contain levelized rates that are still in operations?

A. Yes, projects are paid based on the kWh of energy they deliver to Idaho Power. Idaho Power has observed that in the early years of a QF agreement, quite often the project delivers more energy than in the later years of the life of project. The Company has assumed this is due to lack of maintenance or normal degradation of the generation equipment. Thus, the financial loan, or overpayment (result of levelized rate structure) provided to the QF project in the early years of the contract is never fully repaid as the project generation decreases in the latter half of the contract term.

Q. Do QF projects need the levelized rates to qualify for project financing?

A. In the early years of PURPA, a common argument presented by QF developers was that they needed the levelized rates (loan from the Idaho Power customers) to enable them to cover initial construction costs and attract financial investors. Idaho Power has executed 51 QF contracts over the last 13 years, and of those contracts, only 5 elected to have levelized rates within their agreements. In fact, very few QF projects today choose to have levelized rates. It appears the need for levelized rate QF agreements is no longer as critical as initially presented by QF developers. Idaho Power recommends that the Commission not require Idaho Power to enter into levelized rate long-term contracts, as they are very harmful to customers.

VIII. ENVIRONMENTAL ATTRIBUTES/RECS

Q. Does Idaho Power have a recommendation in this case regarding the ownership of environmental attributes generated with the energy purchased from a QF?

A. Yes. Idaho Power recommends that the Commission determine that environmental attributes generated by a QF project should be owned by Idaho Power whenever that QF sells energy to the Company and receives compensation for that energy at avoided cost rates.

Q. Did Idaho Power also present this request in the general PURPA docket in Idaho?

A. Yes. In my response testimony for the Idaho Commission's GNR-E-11-03 PURPA docket, Idaho Power adopted the direct testimony and positions advocated by Rocky Mountain Power by its witness Paul Clements. The Company puts forth the same position to the Commission here.

Q. Is the Company's recommendation regarding ownership of environmental attributes supported by PURPA?

A. Yes. Section 210 of PURPA requires utilities to buy power from generation fueled by specific resources, such as biomass, solar, wind, waste, and geothermal, or in specific configurations, such as cogeneration. If those generators were not powered by those specific resources, utilities would not be required to purchase that energy under PURPA.

Q. Should the utility pay the QF separately for the ownership of environmental attributes?

A. No. In that situation, the utility would then be paying above its avoided cost. If the utility were to pay a QF separately for the environmental attributes, the utility and its customers would in effect be paying twice for that attribute and thus be paying in excess of avoided cost.

Q. Can you explain?

A. Yes. PURPA contains no requirement that a purchasing utility pay twice for what it has already bought. PURPA requires that utilities purchase from QFs, and QFs are afforded that designation because of fuel use or efficiency criteria. A utility must purchase from a QF because of the generation's environmental attributes. Without these characteristics, the generator would not be able to require the utility to purchase its energy at all. In other words, it is only by virtue of the existence of the environmental attributes that facilities are deemed QFs and utilities become obligated to purchase their power. In the case of eligible renewable energy resource QFs, these environmental attributes are the essence of the requirements to purchase the output, and is therefore part of what the utility is buying with the payment of avoided costs. If Idaho Power does not get the QF environmental attributes, it is not receiving the very characteristic that enabled the facility to achieve its QF status, and which thereby triggered the utility's obligation to purchase the output from the facility. The utility would not be receiving the full output of the QF that it was required to purchase.

Simply because one attribute of what has always been sold pursuant to PURPA contracts subsequently acquires a separate market value does not mean that particular attribute now warrants separate compensation, just as it does not mean that the attribute has been, or is being, transferred without consideration. A purchasing utility under a QF contract is not buying undifferentiated energy from the grid, it is buying energy that is very particularly differentiated to such an extent that the utility is required by law to buy it at the special price known as "avoided cost." Under PURPA, the utility has the obligation of purchasing energy from a differentiated resource at the utility's avoided cost. Absent utility ownership of all the differentiated resource's attributes, the utility is paying higher than its true avoided cost.

Any PURPA power purchase agreement securing power from an eligible renewable energy resource should therefore credit the associated environmental attributes to the purchasing utility.

IX. LEGALLY ENFORCEABLE OBLIGATION

Q. Does the Commission have any rules related to the issue of a Legally Enforceable Obligation ("LEO")?

A. Yes. Under ORS 758.525(2), a QF may choose an avoided cost price based on either the avoided costs calculated at the time of delivery or the "projected avoided costs calculated at the time the legal obligation to purchase the energy or energy and capacity is incurred." While the statute does not define the time at which the legal obligation is incurred, the Commission's rules do. OAR 860-029-0010(29) defines the "time the obligation to purchase the energy capacity or energy and capacity is incurred" as the earlier of:

> (a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity; or
>
> (b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

Q. Does the Commission have any past precedent of applying this rule?

A. Yes. In Order No. 09-439 in Docket UM 1449, a QF larger than 10 MW was in the process of negotiating a Power Purchase Agreement ("PPA") with PacifiCorp when PacifiCorp filed to update its avoided cost prices. After the Commission approved PacifiCorp's new prices, the QF filed a complaint requesting that the Commission require PacifiCorp to execute a PPA with the QF that included the previous avoided cost prices in effect during negotiations. In granting PacifiCorp's motion to dismiss the QF's complaint, the Commission found that under OAR 860-029-0010(29)(b) a legally enforceable obligation was not created simply by PacifiCorp's provision of a draft PPA to the QF. The Commission noted that conventional contract law does not apply to QF transactions because they are creatures of statutes and the Commission's rules. Therefore, acceptance of the terms of the draft contract does not constitute an agreement and because the draft contract was not a binding written agreement between the parties, PacifiCorp had not incurred a legally binding obligation.

Q. What is Idaho Power's position regarding a LEO?

A. Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PURPA contract itself, regardless of whether the utility signs. Further, that there must be some evidence of the utility's refusal to contract, or purposeful delay in the contracting process on the part of the utility, before a QF could avail itself of the remedy of creating a legally enforceable obligation to a particular rate or particular terms and conditions. If the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established.

Q. What is FERC's rationale for the existence of its rule regarding a LEO?

A. FERC's rationale is that the concept of a legally enforceable obligation exists in order to protect a QF against a situation where a utility refuses to contract with the QF. FERC's rules state that a QF may choose to sell its output to a utility pursuant to a contract or a legally enforceable obligation. FERC has further stated:

> Thus under our regulation, a QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA.

137 FERC 61006 p. 8.

Q. Does this mean that a QF could simply sign a contract and send it to the utility, and by doing so create a "Legally Enforceable Obligation" and bind the utility to a certain rate or certain terms and conditions that may be in effect?

A. No. It is clear that there must be some refusal of the utility to contract, or some purposeful delay, or action on the part of the utility seeking to avoid its obligation to purchase under PURPA, before a QF may avail itself of the extraordinary remedy of consummating a purchase through a non-contractual, but still legally enforceable, obligation. A QF will typically seek the establishment of a LEO in an attempt to secure a higher avoided cost rate, when the state commission approves or puts into place, a new lower avoided cost rate for the utility. Consequently, the establishment, or not, of a LEO in this context holds important, meaningful, and potentially very costly consequences for the utility's customers, if they are bound to pay a previously effective "grandfathered" avoided cost rate that is no longer reflective of the utility's avoided cost.

Q. Has FERC directed that a state commission cannot limit a LEO to when there is a signed contract?

A. FERC has stated in a series of three nearly identical declaratory orders that the Idaho Commission's orders denying the approval of several PURPA power purchase agreements could not limit the application of a legally enforceable obligation to only such time as both the QF and the utility had fully executed the contract. FERC reasoned that because the concept of a LEO is to guard against the eventuality that a utility may refuse to contract to avoid its obligation under PURPA, that it would frustrate that purpose to limit a legally enforceable obligation to only such time as both the QF and the utility had signed the contract.

Q. Did FERC find the existence of a LEO in any of the above-referenced declaratory orders?

A. No. In fact, FERC acknowledged that the factual determination of whether and when a LEO is created or arises is a determination left to the state commissions, and FERC specifically declined to find that a LEO either existed or not under the facts of any of those particular cases.

Q. Is Idaho Power's recommendation to this Commission consistent with FERC's direction regarding a LEO?

A. Yes. Because such determinations are within the province of the state commissions, and because even though a LEO exists at the point in time when both the QF and utility sign the contract, the existence of a LEO cannot be limited to arise only at that time; Idaho Power's recommendations with regard to a LEO satisfies both the FERC's direction that a LEO not be limited to when both parties sign, but also leaves the decision as to whether the remedy of a LEO shall be applied in any particular case, and any particular set of factual circumstances, to the discretion of the state commission.

Idaho Power asks that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PURPA contract itself, regardless of whether the utility signs. Further, that there must be some evidence of the utility's refusal to contract, or purposeful delay in the contracting process, before a QF could avail itself of the legally enforceable obligation. If the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established. These requirements both comport with FERC's guidance regarding a LEO, and ensure that the utility's customers do not pay a rate that exceeds the utility's avoided cost.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of M. Mark Stokes
Idaho Power PURPA QF Project List as of December 31, 2012

February 4, 2013

PURPA QF Projects as of December 31, 2012

On-line	Resource Type	Project Name	State	County	MW
1	Biomass	B6 Anaerobic Digester	ID	Gooding	2.28
2	Biomass	Bettencourt Dry Creek BioFactory, LLC	ID	Twin Falls	2.25
3	Biomass	Big Sky West Dairy Digester (DF-AP #1, LLC)	ID	Gooding	1.50
4	Biomass	Double A Digester Project	ID	Lincoln	4.50
5	Biomass	Hidden Hollow Landfill Gas	ID	Ada	3.20
6	Biomass	Pocatello Waste	ID	Bannock	0.46
7	Biomass	Rock Creek Dairy	ID	Twin Falls	4.00
8	Biomass	Tamarack Cspp	ID	Adams	5.00
9	CoGen	Simplot Pocatello	ID	Power	12.00
10	Hydro	Arena Drop	ID	Canyon	0.45
11	Hydro	Barber Dam	ID	Ada	3.70
12	Hydro	Birch Creek	ID	Gooding	0.05
13	Hydro	Black Canyon #3	ID	Gooding	0.14
14	Hydro	Blind Canyon	ID	Gooding	1.50
15	Hydro	Box Canyon	ID	Twin Falls	0.36
16	Hydro	Briggs Creek	ID	Twin Falls	0.60
17	Hydro	Bypass	ID	Jerome	9.96
18	Hydro	Canyon Springs	ID	Twin Falls	0.13
19	Hydro	Cedar Draw	ID	Twin Falls	1.55
20	Hydro	Clear Springs Trout	ID	Twin Falls	0.52
21	Hydro	Crystal Springs	ID	Twin Falls	2.44
22	Hydro	Curry Cattle Company	ID	Twin Falls	0.22
23	Hydro	Dietrich Drop	ID	Jerome	4.50
24	Hydro	Elk Creek	ID	Idaho	2.00
25	Hydro	Falls River	ID	Fremont	9.10
26	Hydro	Faulkner Ranch	ID	Gooding	0.87
27	Hydro	Fisheries Dev.	ID	Gooding	0.26
28	Hydro	Geo-Bon #2	ID	Lincoln	0.93
29	Hydro	Hailey Cspp	ID	Blaine	0.06
30	Hydro	Hazelton A	ID	Jerome	8.10
31	Hydro	Hazelton B	ID	Jerome	7.60
32	Hydro	Horseshoe Bend Hydro	ID	Boise	9.50
33	Hydro	Jim Knight	ID	Gooding	0.34
34	Hydro	Kasel & Witherspoon	ID	Twin Falls	0.90
35	Hydro	Koyle Small Hydro	ID	Gooding	1.25
36	Hydro	Lateral # 10	ID	Twin Falls	2.06
37	Hydro	Lemoyne	ID	Gooding	0.08
38	Hydro	Little Wood Rvr Res	ID	Blaine	2.85
39	Hydro	Littlewood / Arkoosh	ID	Lincoln	0.87
40	Hydro	Low Line Canal	ID	Twin Falls	7.97
41	Hydro	Low Line Midway Hydro	ID	Twin Falls	2.50
42	Hydro	Lowline #2	ID	Twin Falls	2.79
43	Hydro	Magic Reservoir	ID	Blaine	9.07
44	Hydro	Malad River	ID	Gooding	0.62
45	Hydro	Marco Ranches	ID	Jerome	1.20
46	Hydro	Mile 28	ID	Jerome	1.50
47	Hydro	Mill Creek Hydroelectric	OR	Union	0.80
48	Hydro	Mitchell Butte	OR	Malheur	2.09
49	Hydro	Mora Drop Small Hydroelectric Facility	ID	Ada	1.85
50	Hydro	Mud Creek/S & S	ID	Twin Falls	0.52

On-line	Resource Type	Project Name	State	County	MW
51	Hydro	Mud Creek/White	ID	Twin Falls	0.21
52	Hydro	Owyhee Dam Cspp	OR	Malheur	5.00
53	Hydro	Pigeon Cove	ID	Twin Falls	1.89
54	Hydro	Pristine Springs #1	ID	Jerome	0.13
55	Hydro	Pristine Springs Hydro #3	ID	Jerome	0.20
56	Hydro	Reynolds Irrigation	ID	Canyon	0.26
57	Hydro	Rim View	ID	Gooding	0.20
58	Hydro	Rock Creek #1	ID	Twin Falls	2.05
59	Hydro	Rock Creek #2	ID	Twin Falls	1.90
60	Hydro	Sagebrush	ID	Lincoln	0.43
61	Hydro	Sahko Hydro	ID	Twin Falls	0.50
62	Hydro	Schaffner	ID	Lemhi	0.53
63	Hydro	Shingle Creek	ID	Adams	0.22
64	Hydro	Shoshone #2	ID	Lincoln	0.58
65	Hydro	Shoshone Cspp	ID	Lincoln	0.37
66	Hydro	Snake River Pottery	ID	Gooding	0.07
67	Hydro	Snedigar	ID	Twin Falls	0.54
68	Hydro	Tiber Dam	ID	Liberty County	7.50
69	Hydro	Trout-Co	ID	Gooding	0.24
70	Hydro	Tunnel #1	OR	Malheur	7.00
71	Hydro	White Water Ranch	ID	Gooding	0.16
72	Hydro	Wilson Lake Hydro	ID	Jerome	8.40
73	Thermal	Magic Valley	ID	Minidoka	10.00
74	Thermal	Magic West	ID	Elmore	10.00
75	Thermal	Tasco - Nampa	ID	Canyon	2.00
76	Thermal	Tasco - Twin Falls	ID	Twin Falls	3.00
77	Wind	Bennett Creek Wind Farm	ID	Elmore	21.00
78	Wind	Burley Butte Wind Park	ID	Cassia	21.30
79	Wind	Camp Reed Wind Park	ID	Elmore	22.50
80	Wind	Cassia Wind Farm LLC	ID	Twin Falls	10.50
81	Wind	Cold Springs Windfarm	ID	Elmore	23.00
82	Wind	Desert Meadow Windfarm	ID	Elmore	23.00
83	Wind	Fossil Gulch Wind	ID	Twin Falls	10.50
84	Wind	Golden Valley Wind	ID	Cassia	12.00
85	Wind	Hammett Hill Windfarm	ID	Elmore	23.00
86	Wind	High Mesa Wind Project	ID	Twin Falls and Elmore	40.00
87	Wind	Horseshoe Bend Wind	MT	Cascade	9.00
88	Wind	Hot Springs Wind Farm	ID	Elmore	21.00
89	Wind	Lime Wind Energy	OR	Baker	3.00
90	Wind	Mainline Windfarm	ID	Elmore	23.00
91	Wind	Milner Dam Wind	ID	Cassia	19.92
92	Wind	Oregon Trail Wind	ID	Twin Falls	13.50
93	Wind	Payne's Ferry Wind Park	ID	Twin Falls	21.00
94	Wind	Pilgrim Stage Station Wind	ID	Twin Falls	10.50
95	Wind	Rockland Wind Farm	ID	Power	80.00
96	Wind	Ryegrass Windfarm	ID	Elmore	23.00
97	Wind	Salmon Falls Wind	ID	Twin Falls	22.00
98	Wind	Sawtooth Wind Project	ID	Elmore	22.00
99	Wind	Thousand Springs Wind	ID	Twin Falls	12.00
100	Wind	Tuana Gulch Wind	ID	Twin Falls	10.50
101	Wind	Tuana Springs Expansion	ID	Twin Falls	35.70
102	Wind	Two Ponds Windfarm	ID	Elmore	23.00
103	Wind	Yahoo Creek Wind Park	ID	Twin Falls	21.00
				Subtotal	**779.26**

Not On-line	Resource Type	Project Name	State	County	MW
1	Biomass	Double B Dairy	ID	Cassia	2.00
2	Biomass	Dynamis Ada County Landfill Project	ID	Ada	22.00
3	Hydro	Clark Canyon Hydroelectric	MT	Beaverhead	4.70
4	Hydro	Fargo Drop Hydroelectric	ID	Canyon	1.27
5	Solar	Grandview Solar PV One	ID	Owyee	20.00
				Subtotal	**49.97**
108	**Total Projects Under Contract**				**829.23**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of M. Mark Stokes
Idaho Power PURPA Expense—Historical and Forecast

February 4, 2013

Idaho Power Company PURPA Expense

Historical

Year	aMW	Expense
1982	0	$ 241,681
1983	3	$ 1,947,675
1984	10	$ 8,419,576
1985	27	$ 16,201,679
1986	45	$ 23,089,962
1987	45	$ 22,938,180
1988	46	$ 23,378,405
1989	55	$ 29,049,008
1990	56	$ 29,409,440
1991	51	$ 27,969,279
1992	43	$ 22,148,359
1993	65	$ 33,596,827
1994	62	$ 30,884,222
1995	75	$ 37,999,969
1996	89	$ 43,716,927
1997	107	$ 55,971,675
1998	104	$ 54,957,741
1999	106	$ 56,152,052
2000	98	$ 53,685,443
2001	83	$ 44,976,174
2002	79	$ 43,931,661
2003	75	$ 38,186,005
2004	77	$ 39,840,544
2005	82	$ 43,327,053
2006	104	$ 53,666,055
2007	89	$ 45,494,057
2008	86	$ 45,885,564
2009	111	$ 59,011,557
2010	104	$ 54,972,118
2011	171	$ 89,674,856
2012	224	$ 116,747,304
	Total	$ 1,247,471,050

Forecast

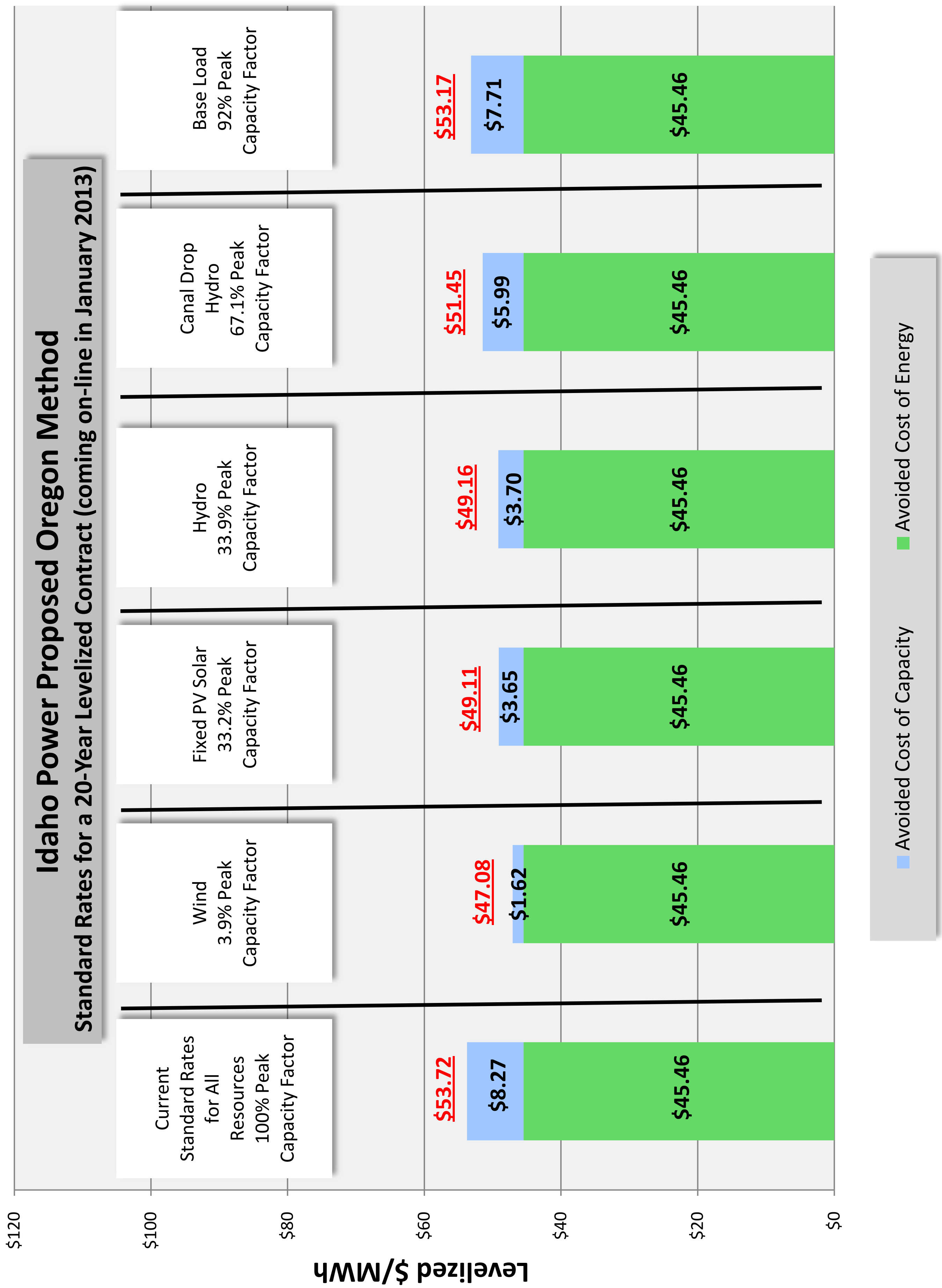
Year	aMW	Expense
2013	235	$ 130,592,980
2014	244	$ 140,463,417
2015	244	$ 144,117,176
2016	244	$ 145,734,803
2017	235	$ 143,445,571
2018	232	$ 144,401,078
2019	228	$ 144,435,649
2020	221	$ 142,123,468
2021	217	$ 143,015,999
2022	216	$ 143,983,695
2023	212	$ 145,535,516
2024	203	$ 144,818,968
2025	201	$ 146,867,925
2026	197	$ 145,883,595
2027	193	$ 146,711,817
2028	185	$ 143,981,420
2029	167	$ 133,475,212
2030	163	$ 132,091,402
2031	105	$ 91,917,839
2032	82	$ 71,309,214
2033	48	$ 40,977,178
2034	33	$ 26,076,641
2035	32	$ 25,458,754
2036	24	$ 21,097,615
2037	2	$ 1,934,223
2038	2	$ 1,934,223
2039	2	$ 1,934,223
2040	2	$ 1,934,223
	Total	$ 2,846,253,826

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of M. Mark Stokes
Idaho Power's Proposed Oregon Method

February 4, 2013

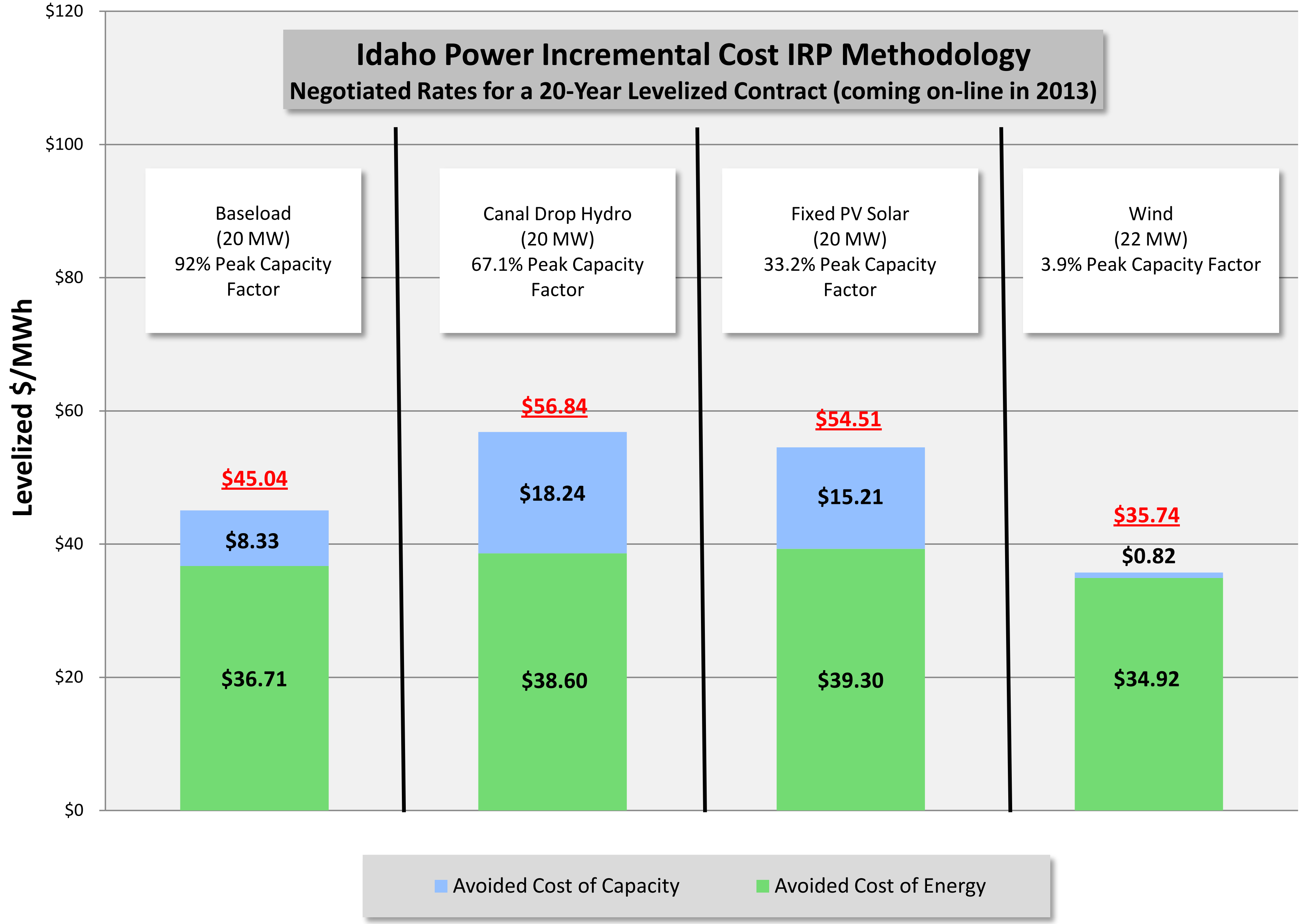

Idaho Power Proposed Oregon Method
Standard Rates for a 20-Year Levelized Contract (coming on-line in January 2013)
Levelized $/MWh
$0
$20
$40
$60
$80
$100
$120
Current Standard Rates for All Resources 100% Peak Capacity Factor
$53.72
$8.27
$45.46
Wind 3.9% Peak Capacity Factor
$47.08
$1.62
$45.46
Fixed PV Solar 33.2% Peak Capacity Factor
$49.11
$3.65
$45.46
Hydro 33.9% Peak Capacity Factor
$49.16
$3.70
$45.46
Canal Drop Hydro 67.1% Peak Capacity Factor
$51.45
$5.99
$45.46
Base Load 92% Peak Capacity Factor
$53.17
$7.71
$45.46
Avoided Cost of Capacity
Avoided Cost of Energy

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of M. Mark Stokes
Idaho Power's Incremental Cost IRP Methodology

February 4, 2013


Idaho Power Incremental Cost IRP Methodology
Negotiated Rates for a 20-Year Levelized Contract (coming on-line in 2013)
Levelized $/MWh
$120
$100
$80
$60
$40
$20
$0
Baseload
(20 MW)
92% Peak Capacity
Factor
Canal Drop Hydro
(20 MW)
67.1% Peak Capacity
Factor
Fixed PV Solar
(20 MW)
33.2% Peak Capacity
Factor
Wind
(22 MW)
3.9% Peak Capacity Factor
$45.04
$8.33
$36.71
$56.84
$18.24
$38.60
$54.51
$15.21
$39.30
$35.74
$0.82
$34.92
Avoided Cost of Capacity
Avoided Cost of Energy

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of M. Mark Stokes
Wind Integration Study

February 4, 2013

Wind Integration Study Report

Idaho Power, 1221 W Idaho Street, Boise, Idaho 83702

February 2013

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

This page left blank intentionally.

EXECUTIVE SUMMARY

As a variable and uncertain generating resource, wind generators require Idaho Power to modify power system operations to successfully integrate such projects without impacting system reliability. The company must build into its generation scheduling extra operating reserves designed to allow dispatchable generators to respond to wind's variability and uncertainty.

Idaho Power, similar to much of the Pacific Northwest, has experienced rapid growth in wind generation over recent years. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 megawatts (MW) of nameplate capacity. The rapid growth in wind generation is illustrated in Figure 1.

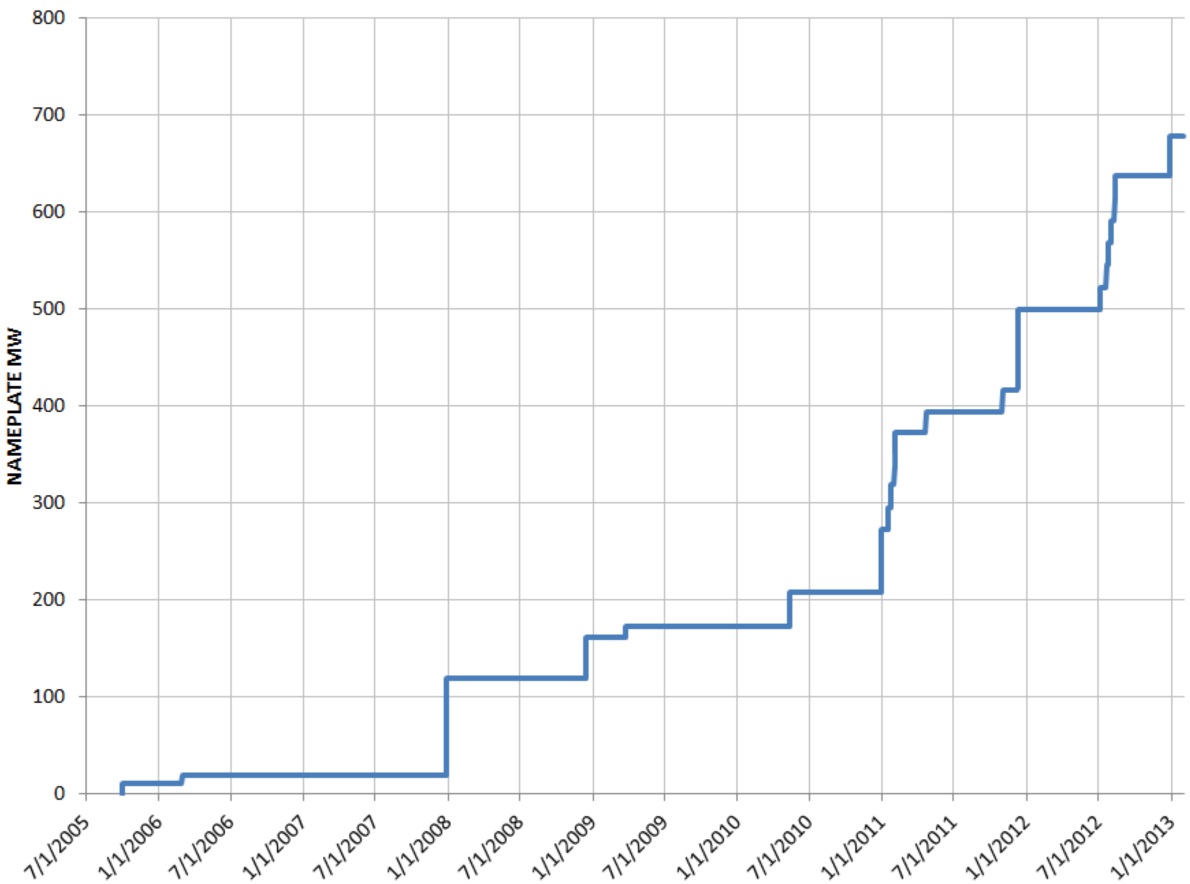


Figure 1 Installed wind capacity connected to the Idaho Power system

This rapid growth has led to the recognition that Idaho Power's finite capability for integrating wind is nearing depletion. Even at the current level of wind penetration, dispatchable thermal and hydro generators are not always capable of providing the balancing reserves necessary to integrate wind. This situation is expected to worsen as wind penetration levels increase.

Balancing Reserves

This investigation quantified wind integration costs for wind installed capacities of 800 MW, 1,000 MW, and 1,200 MW. Synthetic wind generation data and corresponding day-ahead wind generation forecasts at these build-outs were provided by Energy Exemplar (formerly PLEXOS

Solutions) and 3TIER. Based on analysis of these data, the following monthly balancing reserves requirements were imposed in system modeling.

Table 1 Balancing reserves requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for on-line generating capacity that can be turned down in response to a wind up-ramp. The balancing reserves requirements assume a 90 percent confidence level and thus are designed to cover deviations in wind relative to forecast except for extreme events comprising 5 percent at each end.

Study Design

The study employed the following two-scenario design:

- Base scenario for which the system was not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system was burdened with the incremental balancing reserves necessary for integrating wind

System simulations for the two scenarios were identical, except that generation scheduling for the test scenario included the condition that dispatchable thermal and hydro generators must provide the appropriate amount of incremental balancing reserves. Having the prescribed balancing reserves positions these generators such that they can respond to changing wind.

System simulations were conducted for a 2017 test year. Customer demand for 2017, as projected for the *2011 Integrated Resource Plan* (IRP), was used in system modeling. To investigate the effect of water conditions on wind integration, the study also considered Snake River Basin stream flows for three separate historic years representing low (2004), average (2009), and high (2006) water years.

Wind Integration Costs

The integration costs in Table 2 were calculated from the system simulations.

Table 2 Wind integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Simulations with the proposed Boardman to Hemingway transmission line were also performed, yielding the results in Table 3.

Table 3 Wind integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Curtailment

The study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Under these circumstances, curtailment of wind generation is often necessary to maintain balance. Modeling demonstrates that the frequency of curtailment is expected to accelerate greatly beyond the 800 MW installed capacity level. While the maximum penetration level cannot be precisely identified, study results indicate wind development beyond 800 MW is subject to considerable curtailment risk. Importantly, curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were assumed to not be made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 2.

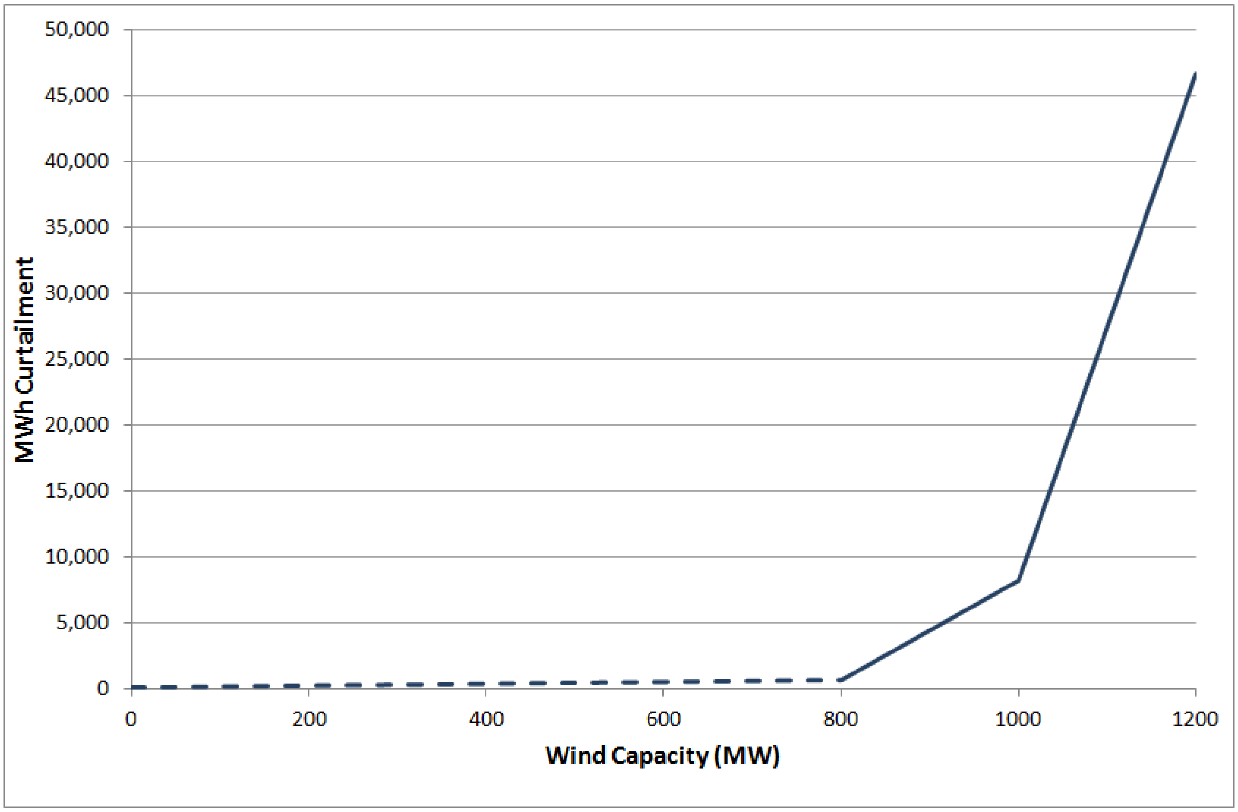


Figure 2 Curtailment of wind generation (average annual MWh)

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 2 and 3 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 2 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[1].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 3 below. The incremental integration costs are summarized in Table 4.

[1] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

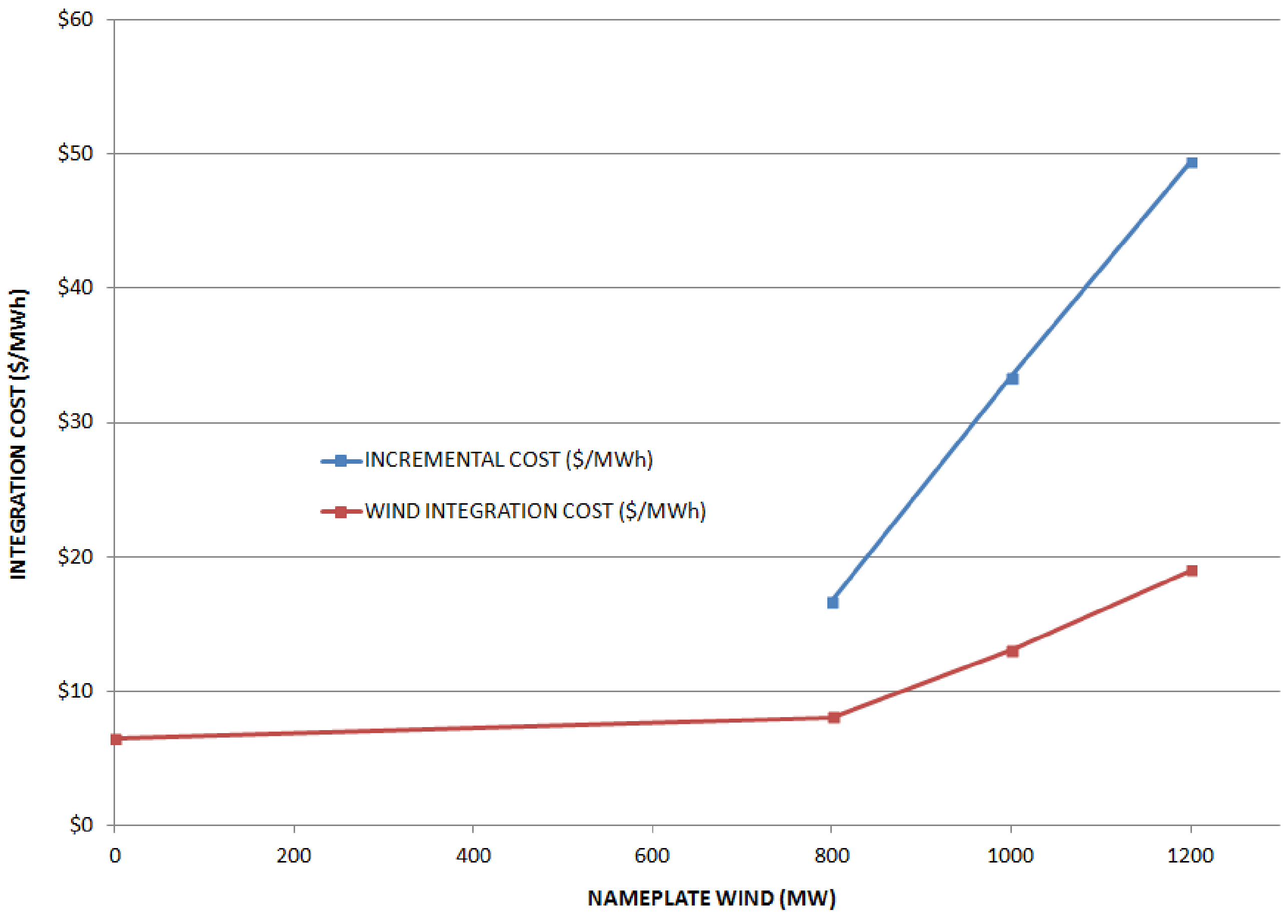


Figure 3 Integration costs with incremental integration costs ($/MWh)

Table 4 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

This page left blank intentionally.

INTRODUCTION

Electrical power generated from wind turbines is commonly known to exhibit greater variability and uncertainty than that from conventional generators. Because of the incremental variability and uncertainty, it is widely recognized that electric utilities incur increased costs when their systems are called on to integrate wind power. These costs occur because power systems are operated less optimally to successfully integrate wind generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the unique modifications it must make to power system operations to integrate the rapidly expanding amount of wind generation connecting to its system. The purpose of this report is to describe the operational modifications taken to integrate wind and the associated costs. The study of these costs is viewed by Idaho Power as an important part of efforts to ensure prices paid for wind power are fair and equitable to customers and generators alike.

Idaho Power first reported on wind integration in 2007. While there was a sizable amount of wind generation under contract in 2007, the amount of wind actually connected to the Idaho Power system at the time of the first study report was just under 20 MW nameplate. Over recent years, the amount of wind generation connected to the Idaho Power system has sharply risen. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 MW nameplate. The rapid growth in wind generation is illustrated in Figure 4.

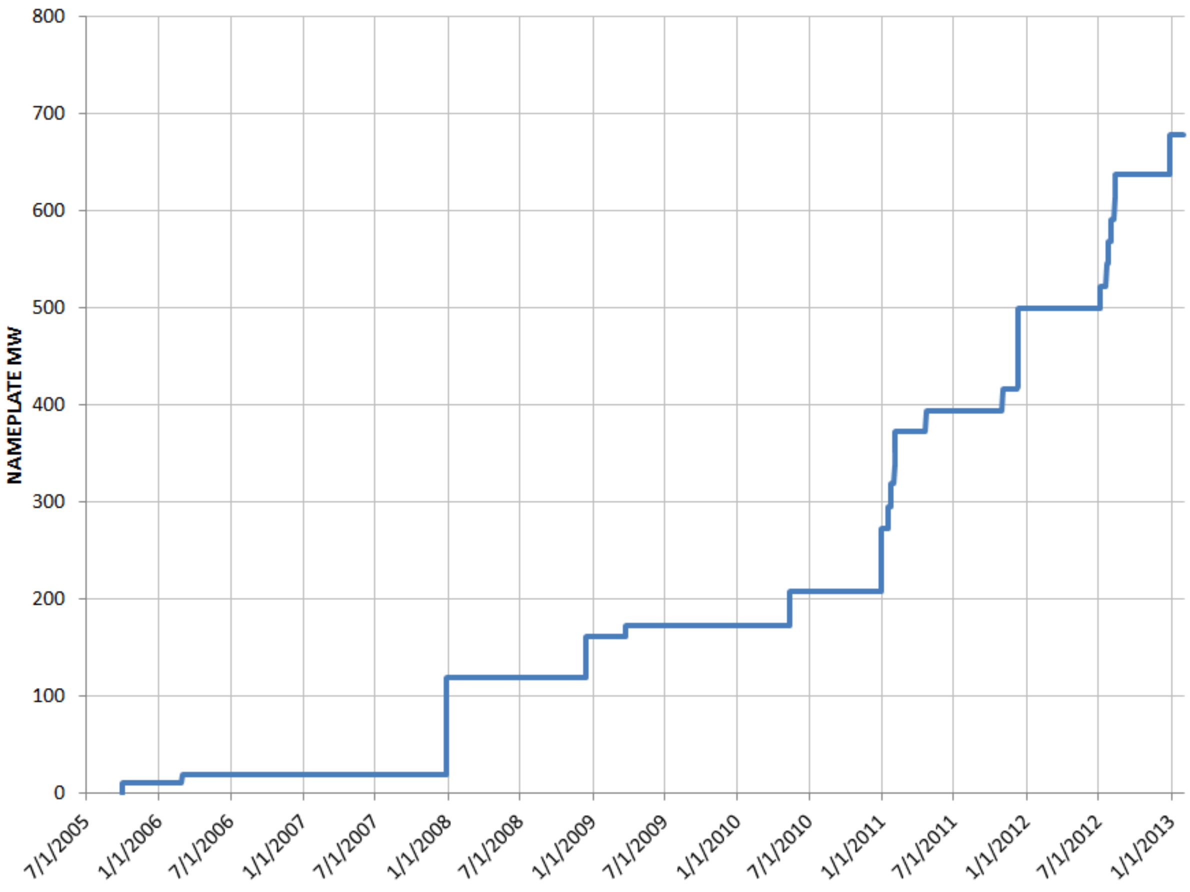


Figure 4 Installed wind capacity connected to the Idaho Power system (MW)

The steep upturn in wind generation has driven Idaho Power to expand its area of concern beyond the operational costs associated with wind integration to the consideration of the maximum wind penetration level its system can reliably integrate. Thus, the objective of the Idaho Power wind integration study is to answer the following two questions:

- What are the costs of integrating wind generation on the Idaho Power system?
- How much wind generation can the Idaho Power system accommodate without impacting reliability?

A critical principle in the operation of a bulk power system is that a balance between generation and demand must generally be maintained. Power system operators have long studied the variability and uncertainty present on the demand side of this balance, and as a matter of standard practice carry operating reserves on dispatchable generators designed to accommodate potential changes in demand. The introduction of significant wind power causes the variability and uncertainty on the generation side of the balance to markedly increase, requiring power system operators to plan for carrying incremental amounts of operating reserves, in this case necessary to accommodate potential changes in wind generation.

For the purposes of this study report, the term *balancing reserves* is used to denote the operating reserves necessary for integrating wind. A document review on wind integration indicates a variety of terms for this quantity. Regardless of term, the property being described is generally the flexibility a balancing authority must carry to reliably respond to variability and uncertainty in wind generation and demand.

A key component in the study of wind integration, as well as the successful in-practice operation of a power system integrating wind, involves the estimation of the additional balancing reserves dispatchable generators must carry to allow the balance between generation and demand to be maintained. Thus, three essential objectives of this report are to describe the analysis performed by Idaho Power to estimate the incremental balancing reserves requirements attributable to wind generation, describe the power system simulations conducted to model the scheduling of the reserves, and estimate associated costs. The study also evaluates situations where the incremental wind-caused balancing reserves exceed the capabilities of Idaho Power's dispatchable generators, putting the system in a position where it cannot accept additional output from wind generators without compromising reliability.

Technical Review Committee

Idaho Power held a public workshop on April 6, 2012, to discuss its work on wind integration. This workshop included a discussion of methodology and preliminary results, as well as a question and answer session. Following the workshop, the company began working with a technical review committee comprised of individuals selected by Idaho Power based on their knowledge of regional issues surrounding wind generation and the operation of electric power systems.

The following members agreed to serve on the committee:

- Ken Dragoon (Ecofys/Northwest Power and Conservation Council)
- Kurt Myers (Idaho National Laboratory [INL])
- Frank Puyleart (Bonneville Power Administration [BPA])
- Rick Sterling (Idaho Public Utilities Commission [IPUC])

The purpose of the work with the technical review committee was to describe in greater detail the study methodology, including an in-depth review of the model used for system simulations for the study. Given this information, the company asked the members of the committee for their specific comments upon release of this wind integration study report. These comments will be specially noted as having been provided by the technical review committee on the basis of its in-depth review of study methods.

Energy Exemplar Contribution

Idaho Power contracted with Energy Exemplar (formerly PLEXOS Solutions) for assistance with the wind integration study. Energy Exemplar's involvement was critical in the development of the wind generation data used for the study, particularly in the development of representative wind generation forecasts used in the analysis to estimate appropriate balancing reserves requirements. Energy Exemplar was also instrumental in the design of the study methodology, providing key counsel in the formulation of the two-scenario study design detailed later in this report.

With respect to system simulations for the wind study, Idaho Power has developed considerable expertise modeling the power system over recent years. In parallel with the Energy Exemplar efforts, Idaho Power developed a model that optimizes the wind, hydro, and thermal generation production. This internally-developed model was used for system simulations included in the wind study.

This page left blank intentionally.

IDAHO POWER SYSTEM OVERVIEW

Idaho Power serves approximately 500,000 customers in southern Idaho and eastern Oregon through the operation of a diversified power system composed of supply- and demand-side resources, as well as significant transmission and distribution infrastructure. From the supply-side perspective, Idaho Power relies heavily on generation from 17 hydroelectric plants on the Snake River and its tributaries. These resources provide the system with electrical power that is low-cost, dependable, and renewable. Idaho Power also shares joint ownership of three coal-fired generating plants and is the sole owner of three natural gas-fired generating plants, including the recently commissioned Langley Gulch Power Plant. With respect to demand-side resources, Idaho Power has received recognition for its demand response programs, particularly the part these dispatchable programs have played in meeting critical summertime capacity needs. Finally, Idaho Power maintains an extensive system of transmission and distribution resources, allowing it to connect to regional power markets, as well as distribute power reliably at the customer level.

Hydroelectric Generating Projects

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 970 average megawatts (aMW), or 8.5 million megawatt hours (MWh), under median water conditions. The backbone of Idaho Power's hydroelectric system is the Hells Canyon Complex (HCC) in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability. The capability to respond to varying load is increasingly being called on to regulate the variable and uncertain delivery of wind generation.

Hydro is Idaho Power's wind integration resource of choice because of its quick response capability as well as large response capacity. However, the capacity of the hydro system to respond to wind variability is recognized as finite; power-system operation, in practice and as simulated for this study, indicates the hydro system is not always able to sufficiently provide the balancing reserves needed for responding to wind. Using the hydro system for wind integration also limits its availability for other opportunities. The costs of these lost opportunities are a significant part of wind integration costs.

For the wind integration study, the hydroelectric generators at the Brownlee and Oxbow dams were designated in the modeling as available for providing wind-caused balancing reserves. This is consistent with system operation in practice, where the generators at these projects are dispatched to provide the overwhelming majority of operating reserves. Under standard operating practice, the remaining hydroelectric generators of the Idaho Power system are not called on for providing operating reserves. Generators at the Lower Salmon, Bliss, and C. J. Strike plants are capable of some ramping for responding to intra-day variation in load. However, under certain flow conditions, the flexibility of the smaller reservoirs to follow even load trends is greatly diminished, and the facilities are operated strictly as run-of-river (ROR) projects.

Coal-Fired Generating Projects

Idaho Power co-owns three coal-fired power plants having a total nameplate capacity of 1,118 MW. With relatively low operating costs, these plants have historically been a reliable source of stable baseload energy for the system. The output from these plants over recent years is somewhat diminished because of a variety of conditions, including relatively high Snake River and Columbia River stream flows, lagging regional demand for electricity associated with slow economic growth, and an oversupply of energy in the region. Idaho Power is currently studying the economics of operating its coal-fired plants, specifically the cost effectiveness of plant upgrades needed for environmental compliance at the Jim Bridger and North Valmy coal plants. The Boardman coal plant in northeastern Oregon will not operate beyond 2020 and Idaho Power's 64 MW share of the plant will no longer be available to serve customer load.

Coal is one of the thermal resources Idaho Power uses to integrate wind generation. Unlike hydro, the fuel for the coal plants comes at a cost. These fuel costs, as well as the lost opportunities created by using the coal capacity to integrate wind, make up another part of the wind integration costs. The coal generators do not have the large range and rapid response provided by the hydro units.

Natural Gas-Fired Generating Projects

Idaho Power owns and operates four simple-cycle combustion turbines totaling 416 MW of nameplate capacity, and recently commissioned a 300 MW combined-cycle combustion turbine. The simple-cycle combustion turbines (located at Danskin and Bennett Mountain project sites) have relatively low capital costs and high variable operating costs. As a consequence of the high operating costs, the simple-cycle turbines have been historically operated primarily in response to peak demand events and have seldom been dispatched to provide operating reserves. Expansion of their operation to provide balancing reserves for integrating wind is projected to lead to a substantial increase in power supply costs.

Idaho Power commissioned in July 2012 the 300 MW Langley Gulch Power Plant. As a combined-cycle combustion turbine, this generating facility has markedly lower operating costs than the simple-cycle units and is consequently expected to be a critical part of the fleet of generators dispatched to provide balancing reserves for responding to variable wind generation.

Transmission and Wholesale Market

Idaho Power has significant transmission connections to regional electric utilities and regional energy markets. The company uses these connections considerably as part of standard operating practice to import and export electrical power. Utilization of these paths on a day-to-day basis is typically driven by economic opportunities; energy is generally imported when prices are low and exported when prices are high. Transmission capacity across the connections does not reduce system balancing reserves requirements. Thus, balancing reserves necessary for reliable power system operation in practice are provided by dispatchable generators. The wholesale power market, as accessed through regional transmission connections, is not able to provide balancing reserves.

Idaho Power's existing transmission system spans southern Idaho from eastern Oregon to western Wyoming and is composed of transmission facilities having voltages ranging from 115 kilovolts (kV) to 500 kV. The sets of lines transmitting power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between southern Idaho load centers such as Boise, Twin Falls, and Pocatello. Idaho Power's transmission system and paths are shown in Figure 5.

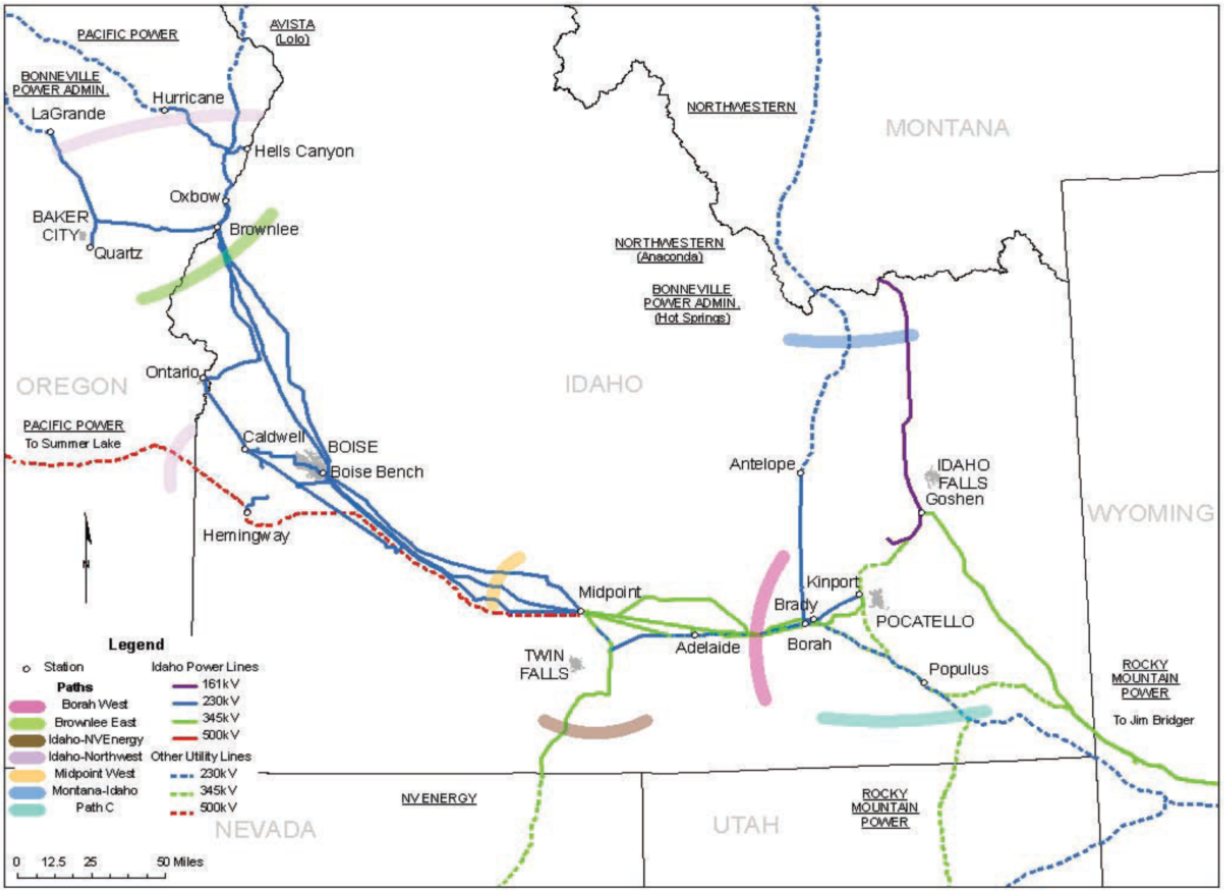


Figure 5 Idaho Power transmission paths

The critical paths from the perspective of providing access to the regional wholesale electricity market are the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. The Boardman to Hemingway transmission line identified by Idaho Power in the preferred portfolio of its 2011 IRP will be an upgrade to the Idaho-Northwest path. The combination of these paths provides Idaho Power effective access to the regional market for the economic exchange of energy.

While Idaho Power does not consider the regional market part of its day-to-day solution for integrating wind generation, it may be necessary during extreme events to use the regional transmission connections and rely on the regional energy market to accommodate wind. The company expects that at times even the regional market will be insufficient to integrate wind. During these times when Idaho Power and the regional market have insufficient balancing reserves to successfully integrate wind generation, it may be necessary to curtail wind, or even curtail customer load, to maintain electrical system stability and integrity.

Power Purchase Agreements

In addition to power purchases in the wholesale market, Idaho Power purchases power pursuant to long-term power purchase agreements (PPA). The company has the following notable firm wholesale PPAs and energy exchange agreements:

- Raft River Energy I, LLC—For up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033.
- Telocaset Wind Power Partners, LLC—For 101 MW (nameplate generation) from the Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.
- USG Oregon LLC—For 22 MW (estimated average annual output) from the Neal Hot Springs geothermal power plant located near Vale, Oregon. The contract term is through 2037 with an option to extend.
- Clatskanie People's Utility District—For the exchange of up to 18 MW of energy from the Arrowrock project in southern Idaho for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is January 1, 2010 through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

System Demand

Idaho Power's all-time system peak demand is 3,245 MW, set on July 12, 2012, and the all-time winter peak demand is 2,527 MW, set on December 10, 2009. An important characteristic of the Idaho Power system is the intra-day range from minimum to maximum customer demand, which during the summer commonly reaches 1,000 MW and occasionally exceeds 1,200 MW. Thus, generating resources that can follow this demand as it systematically grows during the day are critical to maintaining reliable system operation. Hydro generators, particularly those of the HCC, provide much of the demand following capability. Recent natural gas-fired resource additions are also instrumental in allowing the system to reliably meet system demand. An additional resource available to the system is the targeted dispatch of demand response programs. These demand-side programs have proven to dependably reduce system demand during extreme summer load events. From the perspective of system reliability, the nature of Idaho Power's customer demand places a premium on the value associated with capacity-providing resources; energy resources, such as wind, contribute markedly less towards promoting system reliability.

It is recognized that production from wind projects does not dependably occur in concert with peak customer demand. In fact, there is a tendency to experience periods during which production from wind and hydro facilities is high and customer demand is low. The coincidence of these circumstances leads to an excess generation condition, where the capability of system generators to reduce their output in response to wind is severely diminished. Such excess generation events have been observed in recent years by Idaho Power and other balancing authorities in the Pacific Northwest. System stability for the balancing authority is maintained during these events through the curtailment of generation, including that from wind-powered facilities.

System Scheduling

Idaho Power schedules its system with the primary objective of ensuring the reliable delivery of electricity to customers at the lowest possible cost. System planning is conducted for multiple time frames ranging from years/months in advance for long-term planning to hour-ahead for real-time operations planning. A fundamental principle in system planning is that each time frame should be driven by the objective of readying the system for more granular time frames. Long-term resource planning (i.e., the IRP) should ensure the system has adequate resources for managing customer demand over the 18-month long-term operations planning window. Long-term operations planning should position the system such that customer demand can be managed over the balance-of-month perspective. Balance-of-month planning should result in a system that can manage demand when scheduling generation day-ahead. Day-ahead scheduling should enable operators to meet demand from a real-time perspective. Finally, real-time energy schedulers should ensure the system is positioned hour-ahead such that reliable service is maintained within the hour.

With the possible exception of the IRP, the scheduling horizons considered by Idaho Power involve transacting with the regional wholesale market. Where the economic scheduling of system generation is insufficient to meet demand, Idaho Power enters into contracts to purchase power off-system through its transmission connections. Conversely, where economically scheduled generation exceeds customer demand, surplus power is sold into the market. Importantly, Federal Energy Regulatory Commission (FERC) rules (FERC order nos. 888/890) stipulate that surplus power sales are sourced by generating resources that have been undesignated from network load service. Undesignation of a variable generating resource, such as wind, for sourcing a third-party sales transaction results in the transacted energy being given a dynamic tag, where tag is the North American Electricity Reliability Corporation (NERC) term representing an energy transaction in the wholesale electricity market.
Balancing authorities experience considerable difficulty attracting a purchaser of dynamically tagged energy. Therefore, as a standard operating practice, Idaho Power sources off-system power sale contracts from its fleet of hydro and thermal generators. With their recognized level of dependability, hydro and thermal generators can be undesignated for sourcing surplus power sales while allowing conventional tagging procedures to be followed.

This page left blank intentionally.

STUDY DESIGN

Idaho Power designed its wind integration study with the objective of isolating in its operations modeling the effects directly related to integrating wind generation. A common study design used towards meeting this objective, and employed by Idaho Power for this study, is to simulate system operations of a future year with projected wind build-outs under the following two scenarios:

- Base scenario for which the system is not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system is burdened with the incremental balancing reserves necessary for integrating wind

A critical feature of this design is to hold equivalent model parameters and inputs between these two scenarios except for balancing reserves. The incremental balancing reserves built into the test scenario simulation necessarily result in higher production costs for the system, a cost difference that can be attributed to wind integration.

The test year selected by Idaho Power for its study is 2017. While in-service for the 500-kV Boardman to Hemingway transmission line is not anticipated before 2018, the study still considered scenarios to investigate the effects of the expanded transmission on wind integration costs. The study assumed customer demand and Mid-Columbia trading hub wholesale prices as projected for 2017 in the 2011 IRP.

As noted previously, as of January 2013 Idaho Power has 678 MW of nameplate wind capacity. Future wind penetrations considered in the study are 800 MW, 1,000 MW, and 1,200 MW of nameplate capacity. The synthetic wind data at these penetration levels, as well as representative day-ahead forecasts, were provided by 3TIER and Energy Exemplar. The synthetic wind data were provided for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for future projects. Further discussion of the study wind data and associated day-ahead forecasts is provided in a May 9, 2012 explanation released by the company (Appendix A).

To investigate the effect of water conditions on wind integration, the study considered Snake River Basin stream flows for three separate historic scenarios representing low (2004), average (2009), and high (2006) water years. Because of their importance in providing balancing reserves to integrate wind, the HCC projects were simulated using the study model to determine their hydroelectric generation under the selected water years. Generation for the remaining hydroelectric projects, which are not in practice called on to provide balancing reserves for integrating wind, was entered for the study as recorded in actual operations for the water years selected.

This page left blank intentionally.

BALANCING RESERVES CALCULATIONS AND OPERATING RESERVES

Critical to the two-case study design is the calculation of the incremental balancing reserves necessary for successfully integrating the future wind penetration build-outs considered. The premise behind these calculations is that Idaho Power's dispatchable generators must have capacity in reserve, allowing them to respond at an acceptable confidence level to the variable and uncertain delivery of wind. Estimates of the appropriate amount of balancing reserves were based on an analysis of errors in day-ahead forecasts of system wind for the wind build-outs considered in the study. In addition to the synthetic time series of hourly wind-generation data, 3TIER provided a representative day-ahead forecast of hourly wind generation. To provide a larger sampling, Energy Exemplar created 100 additional day-ahead forecasts having similar accuracy as the 3TIER forecast. Summaries of the synthetic wind data and day-ahead forecasts are included in Appendix B. An illustration of this design is given in Figure 6.

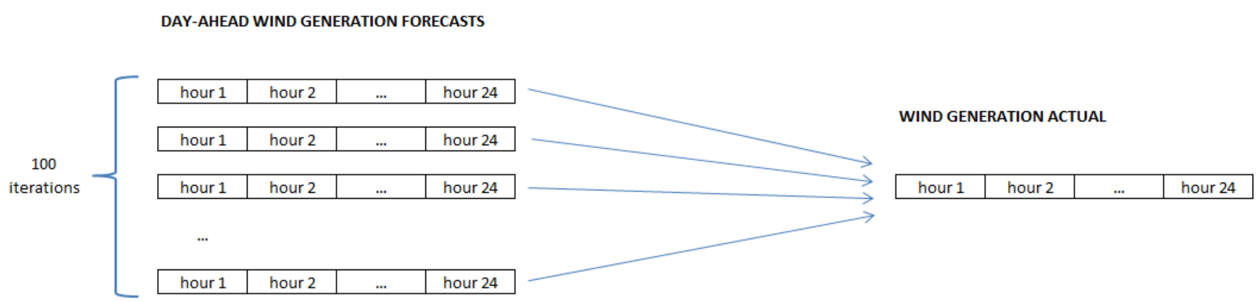


Figure 6 Wind-forecasting and generation data

In recognition of the seasonality of wind, the data were grouped by month, yielding balancing reserves estimates specific to each month. The sample size for each month was extremely large. As an example, for July there were 74,400 deviations between the day-ahead forecast and actual wind generation (100 forecasts × 31 days × 24 hours). The balancing reserves requirements were calculated as the bi-directional capacity covering 90 percent of the deviations. The use of the 90 percent confidence level for the wind integration analysis is consistent with the criterion used for hydro conditions in assessing peak-hour resource adequacy in integrated resource planning.

Figure 7 is an illustration of a full year of deviations for a single forecast iteration at the 1,200 MW penetration level. In this figure, the deviations on the positive side correspond to deviations where actual wind was lower than day-ahead forecast wind, while deviations on the negative side reflect instances where actual wind exceeded the forecast. Importantly, the balancing reserves requirements did not cover the full extent of the deviations, leaving extreme tail events in both directions uncovered.

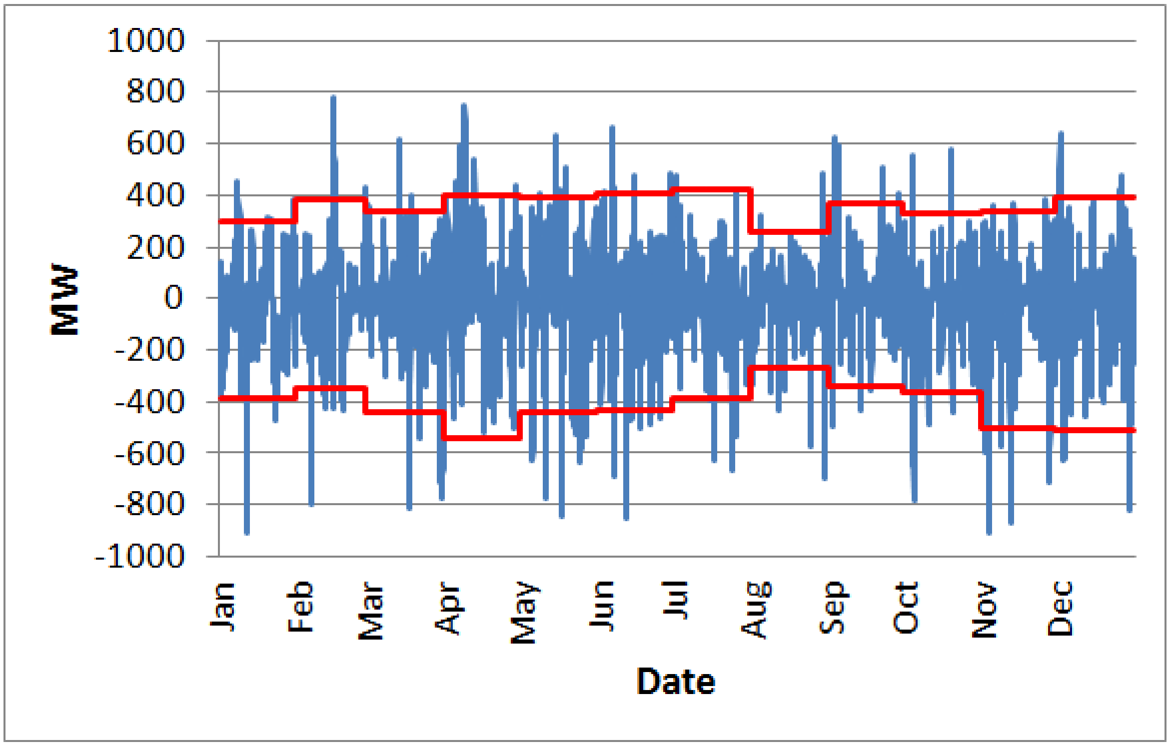


Figure 7 Deviations between forecast and actual wind generation with monthly balancing reserves requirements (MW)

The requirements are dynamic in that the forecast wind was taken into account in imposing the amount of balancing reserves. For example, the requirements suggest that for the 1,200 MW wind penetration level, 295 MW of unloaded generating capacity should be held as balancing reserves in January to guard against a drop in wind relative to the forecast. However, if the forecast wind generation is only 250 MW, then the most wind can drop relative to forecast is 250 MW, which is then the amount of balancing reserves built into the generation schedule. As a second example, if the forecast wind generation is 350 MW, the analysis of wind data indicates that balancing reserves should be held to guard against wind dropping to 55 MW. The likelihood of wind dropping below 55 MW is small (5 percent), and balancing reserves are not scheduled on dispatchable generators for covering a drop in wind to less than 55 MW.

The monthly requirements for balancing reserves are given in Table 5 for the wind penetration levels studied. The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for online generating capacity that can be turned down in response to a wind up-ramp.

Table 5 Balancing reserve requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

Balancing Reserves for Variability and Uncertainty in System Demand

As described previously, power system operation has long needed to hold bidirectional capacity for responding to variability and uncertainty in system demand. For the wind study modeling, Idaho Power imposed a balancing reserves requirement equal to 3 percent of the system demand as capacity reserved to allow for variability and uncertainty in load. This capacity was carried in equal amounts in the two scenarios modeled: the base scenario where the system was not burdened with wind-caused balancing reserves, and the test scenario where a wind-caused balancing reserves requirement was assumed necessary. For the test scenario modeling, the separate load- and wind-caused reserves components were added to yield the total bidirectional balancing reserves requirement. This approach for combining the reserves components is consistent with Idaho Power operations in practice for which system operators receive separate forecasts for wind and demand and combine the estimated uncertainty about these projections through straight addition.

Contingency Reserve Obligation

The variability and uncertainty in demand and wind are routine factors in power system operation and require a system to carry the bidirectional balancing reserves described in this section for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity for responding to system contingency events, which have traditionally been viewed as large and relatively infrequent system disturbances affecting the production or transmission of power (e.g., loss of a major generating unit or major transmission line).
System modeling for the wind study imposed a contingency reserve intended to reflect this obligation equal to 3 percent of load and 3 percent of generation, setting aside this capacity for both scenarios (i.e., base and test). The requirement to carry at least half of the contingency reserve obligation on generators that are spinning and grid-synchronized was also captured in the modeling.

This page left blank intentionally.

System Modeling

Idaho Power used an internally developed system operations model for this study. The model determines optimal hourly scheduling of dispatchable hydro and thermal generators with the objective of minimizing production costs while honoring constraints imposed on the system. System constraints used in the model capture numerous restrictions governing the operation of the power system, including the following:

- Reservoir headwater constraints
- Minimum reservoir outflow constraints
- Reservoir outflow ramping rate constraints
- Wholesale market activity constraints
- Generator minimum/maximum output levels
- Transfer capacity constraints over transmission paths
- Generator ramping rates

The model also stipulated that demand and resources were exactly in balance, and importantly that hourly balancing reserves requirements for variability and uncertainty in load and wind were satisfied. The incremental balancing reserves required for wind variability and uncertainty drove the production cost differences between the study's two cases.

Day-Ahead Scheduling

The hourly scheduling determined by the model was intended to represent the optimal day-ahead system dispatch. This dispatch schedule included generation scheduling for thermal and hydro generators, as well as market transactions. Key inputs to the generation scheduling were the forecasts for wind production and customer demand. These two elements of the generation/load balance commonly carry the greatest uncertainty for power system operation in practice. A fundamental premise of reliable operations for a balancing authority is the need to carry reasonable and prudent flexibility in the day-ahead generation schedule, allowing the system to respond to errors in demand and wind generation forecasts. This principle was built into the wind study modeling in the form of balancing reserves constraints the model must honor. In the two-case study design, the system modeling for the base case included constraints only for demand uncertainty, whereas constraints for the test case included the need to carry additional balancing reserves for wind uncertainty. The derivation of the balancing reserves constraints is described previously in this report.

The critical decision day-ahead generation schedulers must make involves how to schedule dispatchable generation units taking into account the following factors:

- Forecasts for demand and wind production
- Production from other non-dispatchable resources (e.g., PPAs)
- Production from ROR hydro resources
- Operating costs of thermal resources
- Water supply for dispatchable hydro resources

- Operating reserves for contingency events
- Flexibility in the schedule for dispatchable generation units allowing them to respond if necessary to deviations between forecast and actual conditions in load and wind

The essence of wind integration and the associated costs is that the amount of balancing reserves that must be carried is greater because of the uncertainty and variability of wind generation.

Demand and Wind Forecasts

The demand forecast used for the modeling was based on the projected hourly load used in the 2011 IRP for the calendar year 2017. The wind production forecast used for the modeling was based on the average of the 100 forecasts provided by 3TIER and Energy Exemplar.

The forecasts for both elements were identical between the study scenarios; the test scenario simply imposed greater balancing reserves constraints to allow for variability and uncertainty in the wind production forecast.

Transmission System Modeling

As noted in the Idaho Power System Overview section, the critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the wind-study modeling, the separate paths were combined to an aggregate path for off-system access. Every October, Idaho Power submits a request to secure firm transmission across its network based on its expected monthly import needs for the next 18 months. The maximum levels used in the modeling for firm import capacity were based on the October 2010 request. The modeling assumed additional import capacity using non-firm transmission. Non-firm imports were assessed a $50/MWh penalty designed to represent the less favorable economics associated with non-firm transmission and typical hourly pricing. The export limits were based on typical levels of outbound capacity observed in practice. The transmission constraints in Table 6 were used in the wind study modeling.

Table 6 Modeled transmission constraints (MW)

Month	Maximum Firm Import (MW)	Maximum Non-Firm Import (MW)	Maximum Export (MW)
January	179	300	500
February	35	300	500
March	0	300	500
April	0	300	500
May	320	300	500
June	262	300	500
July	149	300	500
August	230	300	500
September	217	300	500
October	0	300	500
November	113	300	500
December	325	300	500

Idaho Power's transmission network is a fundamental part of the vertically integrated power system, and allows the company to participate in the regional wholesale market to serve load or for economic benefit. However, Idaho Power does not view its transmission network with associated regional interconnections as a resource for providing balancing reserves allowing it to respond to variability and uncertainty in wind generation and customer demand. In the region, each balancing authority provides its own balancing reserves. Idaho Power provides its balancing reserves from company-owned dispatchable generation units (thermal and hydro).

Idaho Power also investigated scenarios with the 500-kV Boardman to Hemingway transmission line. For these scenarios, the maximum firm import constraint was increased by 500 MW during April through September and by 200 MW for the remainder of the year. The maximum export constraint was increased by 150 MW throughout the year. The following transmission constraints were used in the wind study modeling for the system with the proposed Boardman to Hemingway transmission line.

Table 7 Modeled transmission constraints—simulations with 500-kV Boardman to Hemingway transmission line (MW)

Month	Maximum Firm Import (MW)	Maximum Non-firm Import (MW)	Maximum Export (MW)
January	379	300	650
February	235	300	650
March	200	300	650
April	500	300	650
May	820	300	650
June	762	300	650
July	649	300	650
August	730	300	650
September	717	300	650
October	200	300	650
November	313	300	650
December	525	300	650

Overgeneration in System Modeling

At a fundamental level, the reliable scheduling of the power system is based on the following simple equation:

Forecast load=Forecast generation

An expanded form of this equation is as follows:

Forecast retail sales + Forecast wholesale sales

=

Forecast dispatchable generation + Forecast wind generation + Forecast other generation

In the expanded equation, dispatchable generation includes scheduled production from resources the balancing authority (i.e., Idaho Power) can vary at its discretion to achieve reliable and economic system operation. Built into this term of the equation is the bidirectional balancing reserves intended for use in case the forecasts for demand or wind generation are incorrect. The other generation in the expanded equation is the amount of energy that cannot be varied. This term includes minimum generation levels at baseload thermal plants, ROR hydro generation, and non-wind power purchased under contract.

At times, the left side of the equation can become very low; Idaho Power customer use is low and wholesale exports are capped by transmission capacity. During these times, providing the balancing reserves necessary for responding to wind, specifically for responding to wind up-ramps, is not possible without upsetting the balance between the two sides of this equation. In effect, the terms of the right side of the equation cannot be reduced enough to match the left. For these times, the wind study modeling assumed the wind, or potential wind, was excessive and could not be accepted; curtailment of wind energy was necessary to maintain balance. Further discussion of overgeneration and curtailment is provided in the following section.

RESULTS

As noted previously, the objective of this study is to answer two fundamental questions:

1. What are the costs of integrating wind generation for the Idaho Power system?

2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

Thus, the results produced by the study's system modeling were designed to address these two questions.

Wind Integration Costs

From a cost perspective, a comparison of annual production costs between two scenarios having different balancing reserves requirements—where the difference in balancing reserves is related to wind's variability and uncertainty—was used to estimate the costs of integrating wind. The production cost difference between scenarios was divided by the annual MWh of wind generation to yield an estimated integration cost expressed on a per MWh basis. The integration cost calculation is summarized as follows:

- Base scenario for which the system was not burdened with incremental balancing reserves necessary for integrating wind (wind integration is "not our problem", a theoretical case used as a benchmark for comparing costs)
- Test scenario for which the system was burdened with incremental balancing reserves necessary for integrating wind

The wind integration cost is the net-cost difference of the two scenarios divided by the MWh of wind generation (the amount of wind generation was the same in both scenarios):

$$\textit{Wind integration cost} = \frac{\textit{Test scenario net cost - Base scenario net cost}}{\textit{Wind generation in MWh}}$$

As noted earlier, the study included three water years and three wind penetration levels. These conditions are shown in Table 8.

Table 8 Wind penetration levels and water conditions

Wind Penetration Level (MW Capacity)	Water Year
800	Low (2004)
1,000	Average (2009)
1,200	High (2006)

A matrix of the wind integration costs on a per MWh basis is given in Table 9. These costs are based on a system without the proposed Boardman to Hemingway transmission line.

Table 9 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

The addition of the Boardman to Hemingway transmission line reduced integration costs slightly. Table 10 provides the wind integration costs for a system having the proposed Boardman to Hemingway transmission line.

Table 10 Integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 9 and 10 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 9 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[2].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 8 below. The incremental integration costs are summarized in Table 11.

[2] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

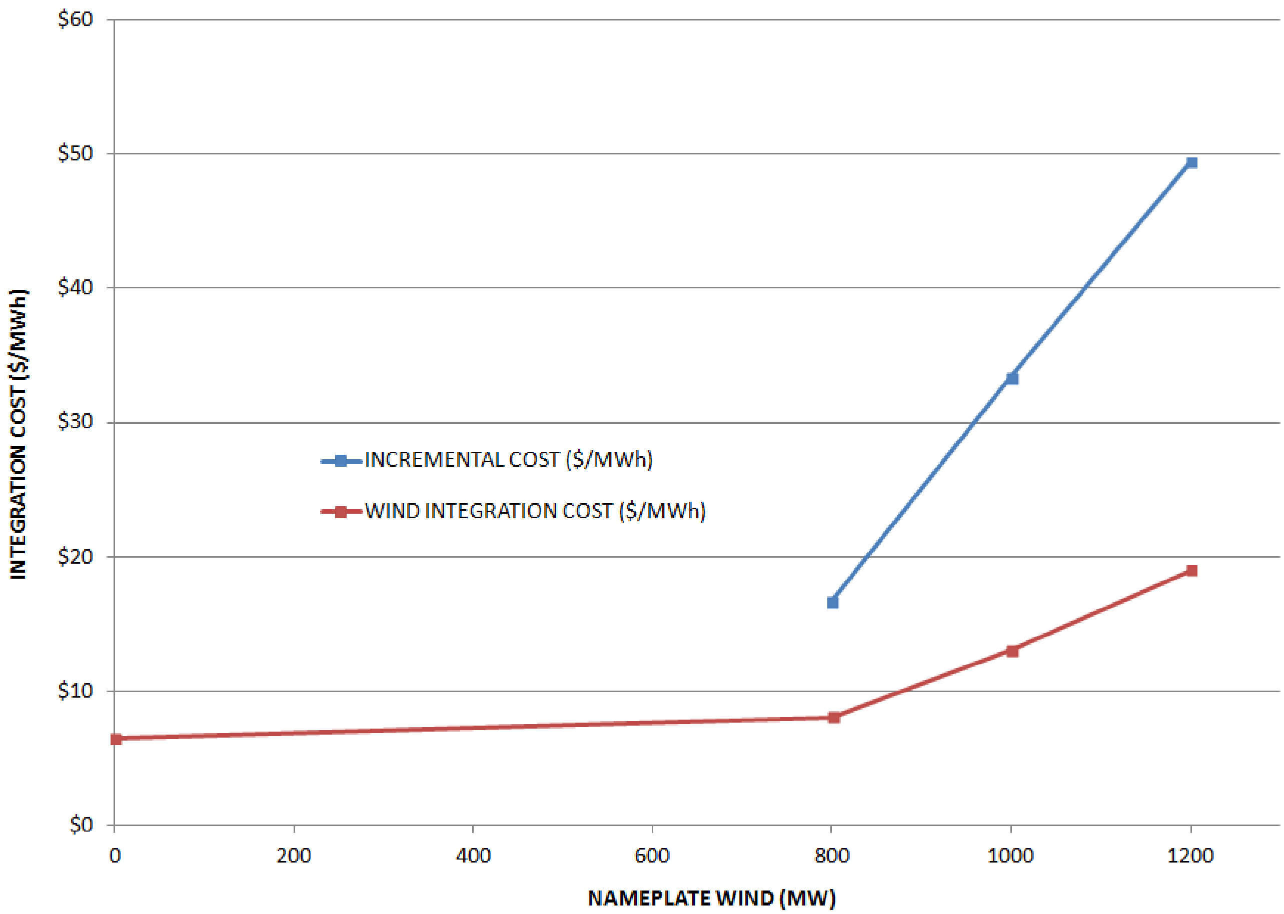


Figure 8 Integration costs with incremental integration costs ($/MWh)

Table 11 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

Spilling Water

The modeling suggests that providing balancing reserves to integrate wind leads to increased spill at the HCC hydroelectric projects. Spill is observed in actual operations during periods of high Brownlee Reservoir inflow coupled with minimal capacity to store water in the reservoir. Minimal storage capacity at Brownlee occurs when the reservoir is nearly full or when the reservoir level is dictated by some other constraint, such as a flood control restriction. Flow through the HCC cannot be significantly reduced during these periods; the three-dam complex is essentially operated as a ROR project during these high-flow periods. As a consequence, holding generating capacity in reserve for balancing purposes is frequently achieved only through increasing project spill, rather than reducing turbine flow. Table 12 provides the total incremental HCC spill in thousands of acre-feet (kaf) associated with integrating wind.

Table 12 Incremental Hells Canyon Complex spill (thousands of acre-feet)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	534 kaf	949 kaf	1,446 kaf
Low (2004)	33 kaf	93 kaf	255 kaf
High (2006)	2,101 kaf	2,698 kaf	2,916 kaf

Simulations for the high water condition (2006) with 800 MW of wind capacity provide a good illustration of the effect of wind integration on spill. Under the base scenario, the theoretical "not our problem" case, wind study system simulation shows spill totaling 3,590 kaf at Brownlee alone. For reference, this simulated spill is within 5 percent of the actual total Brownlee spill in 2006, which was about 3,800 kaf. By comparison, the total Brownlee spill under the test scenario, where integrating wind is Idaho Power's problem, is 4,475 kaf. The excess spill under the test scenario translates to about 185 gigawatt hours (GWh) of lost power production at Brownlee—energy that is no longer available for serving load or off-system sales.

Maximum Idaho Power System Wind Penetration

The capability of the Idaho Power system to integrate wind is finite. The rapid growth in wind capacity connecting to the system over recent years has heightened concern that the limits of this integration capability are being neared, and that development beyond these limits will severely jeopardize system reliability. The quantity of wind generation Idaho Power can integrate varies throughout the year as a function of customer load. During times of high load, Idaho Power can integrate more wind than during times of low load.

Modeling performed for the wind study has demonstrated the occurrence during low load periods where the balancing reserves necessary for responding to a wind up-ramp (i.e., generation that can be dispatched down in response to an increase in wind) cannot be provided without pushing the system to an overgeneration condition. Customer load for these periods, where load consists of sales to retail customers and to wholesale customers by way of regional transmission connections, is too low to allow for the integration of a significant quantity of wind. This situation requires curtailment of wind generation to maintain system balance. For the wind study modeling, the curtailed wind generation was removed from the production cost analysis and consequently did not affect the calculated integration cost. Curtailed wind was not integrated in the modeling and had no influence on the calculated integration costs. Not surprisingly, curtailment was found in the wind study modeling to have a strong correlation with customer load, water condition, and wind penetration levels. A summary of the amount of curtailment in the study is provided in Table 13.

Table 13 Curtailment of wind generation (annual MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	738 MWh	8,755 MWh	48,942 MWh
Low (2004)	204 MWh	3,494 MWh	29,574 MWh
High (2006)	890 MWh	12,519 MWh	61,557 MWh
Average	**611 MWh**	**8,256 MWh**	**46,691 MWh**

Figure 9 illustrates the projected exponential increase in curtailment as a function of the wind penetration level.

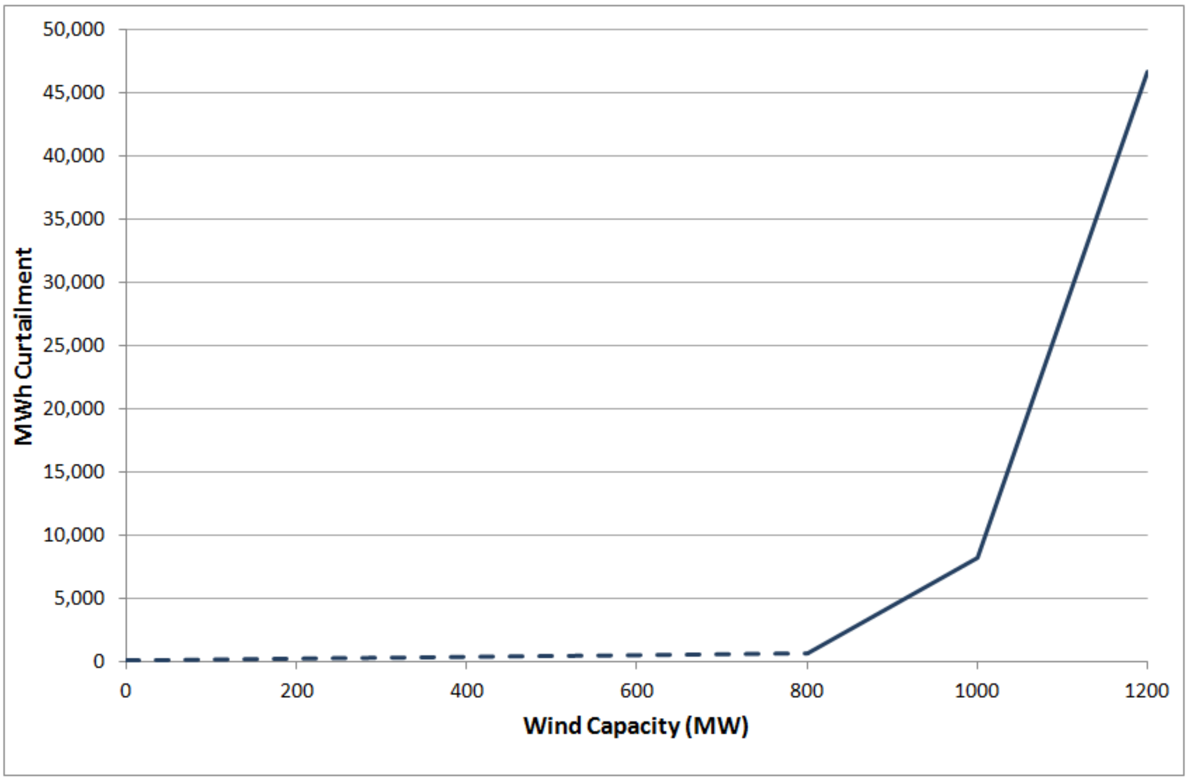


Figure 9 Curtailment of wind generation (average annual MWh)

A key feature of Figure 9 is the rapid acceleration of projected curtailment as installed wind capacity increases beyond the 800 MW level. The addition of 200 MW of installed wind capacity from 800 MW to 1,000 MW is projected to result in about 7,600 MWh of additional curtailment. Increasing the installed wind capacity 200 MW further to 1,200 MW is projected to result in another 38,000 MWh of curtailment. It is important to note the effect of a procedure for curtailment. Spreading the curtailed MWh over the full installed wind capacity of 1,200 MW results in a projected curtailment of about 1.5 percent of produced wind energy. However, if wind generators comprising the expansion from 1,000 MW to 1,200 MW are required under an established policy to shoulder the curtailment burden arising from their addition to the system, curtailment of their energy production is projected to reach nearly 8.5 percent.

The study results suggest that the occurrence of low load periods for which curtailment is necessary is likely to remain relatively infrequent for wind penetration levels of 800 MW or less. However, the results indicate that operational challenges are likely to grow markedly more severe with expanding wind penetration beyond 800 MW of installed nameplate capacity. The occurrence of low load periods for which balancing reserves cannot be provided without causing overgeneration is expected to become more frequent and require deeper curtailment of wind production. This is particularly true in that it is often necessary to maintain the operation of thermal (i.e., gas- and coal-fired) generators during periods of low load and high wind, in order to have the dispatchable generation from these resources available should customer loads increase or winds decrease.

Effect of Wind Integration on Thermal Generation

Idaho Power operates its coal resources to provide low-cost, dependable baseload energy. However, the study results suggest that the operation of the company's coal resources is likely to decrease on an annual basis with expanding wind penetration. The reduction in coal output is principally the result of displacement of coal generation by wind generation, as well as the displacement by flexible gas-fired plants required to help balance the variable and uncertain delivery of wind.

The operation of coal-fired generators has been affected by energy oversupply conditions over recent years in the Pacific Northwest. Coal plants have historically been operated less during periods of high hydro production, and maintenance is typically scheduled to coincide with spring runoff when customer demand is relatively low. However, the expansion of wind capacity over recent years in the region has caused overgeneration conditions to become more severe and longer lasting, leading to extended periods during which prices in the wholesale market have been very low or negative. The effect on coal plants has been a decline in annual energy production. However, during periods when customer load is high, such as during summer 2012, Idaho Power's coal fleet is consistently relied upon for energy to meet the high customer demand.

While the operation of baseload coal-fired power plants is expected to decline as a consequence of adding wind to a power system, this decline is offset by a marked increase in generation from gas-fired plants. The rapidly dispatched capacity from the gas-fired plants is widely recognized as critical to the successful integration of variable generation. Wind study modeling suggests that the need to dispatch gas-fired generators for balancing reserves is likely to displace the economic operation of coal-fired generators, particularly during times of acute transmission congestion.

This situation where relatively low-cost baseload resources are displaced by flexible cycling plants (i.e., gas-fired) is described in a 2010 NREL report (Denholm et al. 2010). Table 14 lists the annual generation from the wind study modeling for thermal resources for the case when Idaho Power is responsible for providing the balancing reserves and integrating the wind energy.

Table 14 Annual generation for thermal generating resources for the test case (GWh)

	Nameplate Wind		
Thermal Resource	**800 MW**	**1,000 MW**	**1,200 MW**
Coal-fired	7,568 GWh	7,291 GWh	6,851 GWh
Gas-fired	963 GWh	1,238 GWh	1,918 GWh

RECOMMENDATIONS AND CONCLUSIONS

Idaho Power has 678 MW of nameplate wind generation on its system. This is a growth in wind capacity of about 290 MW over the last two years, and 490 MW over the last three. The explosive growth in wind generation has heightened concerns that the finite capability of Idaho Power's system to integrate wind is being rapidly depleted. Because of these concerns, the objective of this investigation is to address not only the costs to modify operations to integrate wind, but also the wind penetration level at which system reliability becomes jeopardized. The questions that drove the investigation are the following:

1. What are the costs of integrating wind generation for the Idaho Power system?

2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

The study utilized a two-scenario design, with a base scenario simulation of operations for a system that was not burdened with incremental balancing reserves for integrating wind and a test scenario simulation for a system burdened with incremental wind-caused balancing reserves. Averaged over the three water conditions considered, the estimated integration costs are $8.06/MWh at 800 MW of installed wind, $13.06/MWh at 1,000 MW of installed wind, and $19.01/MWh at 1,200 MW of installed wind. A summary of the estimated costs is given in Table 15.

Table 15 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Importantly, the system modeling conducted for the study indicates a major determinant of ability to integrate is customer demand. This finding is not to be confused with the pricing of wind contracts and the wide recognition that wind occurring during low load periods is of little value. Instead, the study indicates that during periods of low load, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Modeling demonstrates that the frequency of these conditions is expected to accelerate greatly beyond the 800 MW installed capacity level, likely requiring a sharp increase in wind curtailment events. Even at current wind penetration levels, these conditions have been observed in actual system operations during periods of high stream flow and low customer demand. While the maximum penetration level cannot be precisely identified, study results indicate that wind development beyond 800 MW is subject to considerable curtailment risk. It is important to remember that curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were not made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 10.

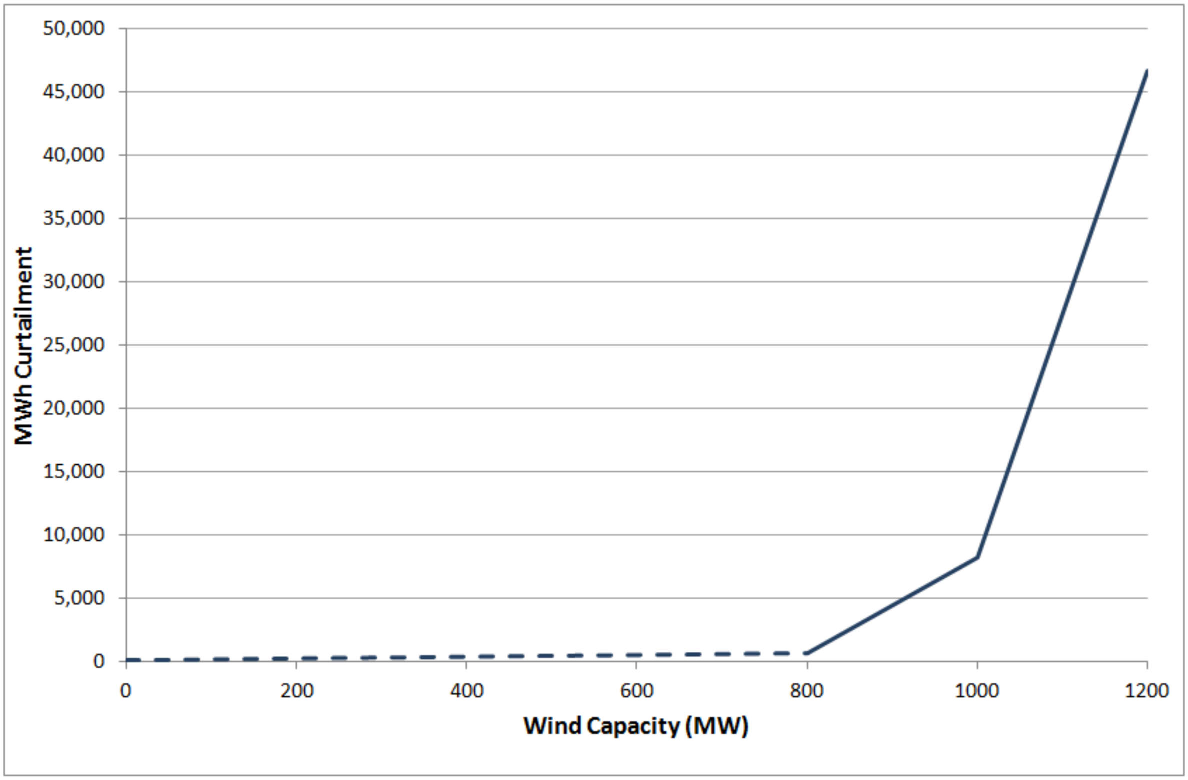


Figure 10 Curtailment of wind generation (average annual MWh)

Conversely, during periods of high customer demand, the dispatchable resources providing the balancing reserves for integrating wind are needed and thus are positioned at levels where they are ready to respond to changes in wind. While the costs to integrate wind still exist during these higher customer demand periods, the system can much more easily accommodate high levels of wind without impacting system reliability.

Issues Not Addressed by the Study

The focus of this study was the variability and uncertainty of wind generation. The study then established that these attributes of wind bring about the need to have balancing reserves at the ready on system dispatchable resources, and finally that having balancing reserves for integrating wind brings about greater costs of production for the system. A consideration not addressed by the study is the increased maintenance costs expected to occur for thermal generating units called on to frequently adjust their output level in response to changes in wind production or that are switched on and off on a more frequent basis. The effect of wind integration on these costs is likely to become evident and better understood with the expanded cycling of these thermal generators accompanying the growth in wind generation over recent years.

The control of system voltage and frequency is receiving considerable attention in the wind integration community. It is widely recognized that the addition of wind generation to a power system has an impact on grid stability. On some transmission systems, controlling system voltage and frequency during large ramps in generation within acceptable limits can be challenging. Idaho Power's system has not yet exhibited this problem at current wind penetration levels. However, growth in wind penetration beyond the current level will lead to greater challenges in maintaining system voltage and frequency within control specifications of the electric system, and likely increase the incidence of excursions where system frequency deviates from normal bands. The effects of frequency excursions may extend to customer equipment and operations.

Measures Facilitating Wind Integration

Idaho Power recognizes the importance of staying current as operating practices evolve and innovations enabling wind integration are introduced. Some changes in operating parameters include mechanisms such as Dynamic Scheduling System (DSS), ACE Diversity Interchange (ADI), and intra-hour markets. Further development of these measures will, to varying degrees, make it easier for balancing authorities to integrate the variable and uncertain delivery of wind generation. At this time, it is Idaho Power's judgment that the effect of these measures is not substantial enough to warrant their inclusion in the modeling performed for this study.

An additional measure that has been studied over recent years as a Western Electricity Coordinating Council (WECC) field trial is reliability-based control (RBC). The essential effect of RBC on operations is that a balancing authority is permitted to carry an imbalance between generation and demand if the imbalance helps achieve wider system stability across the aggregated balancing area of the participating entities. In effect, the balancing authority area is expanded, and the diversity of the expanded area allows an aggregate balance to be more readily maintained. Idaho Power has participated in the RBC field trial since the program's inception, and has recognized a resulting decrease in the amount of cycling required of generating units for balancing purposes. However, the effect of RBC was not included in the modeling for this study. This omission is in part related to the status of the program as a field trial, and related uncertainty regarding the structure of RBC in the future, or whether RBC will exist at all. Moreover, while RBC may allow balancing reserves-carrying generators to not respond to changes in load or wind in real-time operations, the scheduling of these generators must still include appropriate amounts of balancing reserves because it is not known at the time of scheduling to what extent an imbalance between generation and load will be permitted.

Future Study of Wind Integration

Idaho Power continues to grapple with new challenges associated with wind integration. The expansion in installed wind capacity over recent years has made the establishment of a best management plan for integrating wind problematic; the amount of installed wind simply keeps growing. It is commonly understood that wind does not always blow, leading to the legitimate concern about having backup capacity in place for when wind generators are not producing. Somewhat ironically, integration experience over recent years throughout the Pacific Northwest has led to heightened concerns about what to do when wind generators are producing and that production is not needed and unable to be stored in regional reservoirs because of minimal storage capacity, and the balancing reserves carried on dispatchable generators only add to the amount of unneeded generation. While it has been recognized that balancing reserves need to be carried for responding to wind up-ramps (i.e., balancing reserves need to be bidirectional), it has only recently become apparent that the Idaho Power system, and even the larger regional system, at times cannot provide these balancing reserves. This experience has shown that it is difficult to predict the integration challenges of tomorrow, but it is safe to say that there will be a need for continued analysis as additional tools, methods, and practices for integrating wind become available.

Idaho Power has experienced success in wind-production forecasting. The company has developed an internal forecast model which system operators are using with increasing confidence. It is likely that the future study of wind integration will make use of this forecast model, specifically in that its relative accuracy will ultimately lead to a reduction in the balancing reserves requirement for wind integration.

However, even accurate wind forecasting cannot eliminate the need for curtailment when wind generation creates a significant imbalance between load and generation.

Finally, the wider region beyond Idaho has added considerable wind capacity over recent years, much of the growth driven by requirements associated with state-legislated renewable portfolio standards. Most of the wind generation has been added outside of local or regional integrated resource planning efforts. The addition of this generating capacity has resulted in recurring energy oversupply issues for the region, a situation that has led the BPA to propose a protocol for managing oversupply (BPA 2013). Regional market prices during these oversupply periods have experienced pronounced declines to very low or even negative levels. Sometimes even the larger regional system and larger regional market cannot successfully integrate all of the wind energy that is produced. It is critical that future modeling for studying wind integration continues to capture the regional expansion of wind generation and its effect on the wholesale market.

LITERATURE CITED

Bonneville Power Administration (BPA). February 2013. Oversupply management protocol, version 2. http://transmission.bpa.gov/ts_business_practices/Content/9_Redispatch_and_Curtailment/Oversupply_mgt_protocol.htm. Accessed on: February 2, 2013.

Denholm, P., E. Ela, B. Kirby, and M. Milligan 2010. The role of energy storage with renewable electricity generation. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, National Renewable Energy Laboratory. Technical Report NREL/TP-6A2-47187, January 2010.

GE Energy 2010. Western wind and solar integration study. Prepared for: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, National Renewable Energy Laboratory. Subcontract Report NREL/SR-550-47434, May 2010.

This page left blank intentionally.

Appendix A. May 9, 2012, Explanation on wind data

WIND INTEGRATION WORKSHOP

STUDY WIND DATA EXPLANATION

MAY 9, 2012

Idaho Power received questions during the April 6 wind integration workshop related to the synthetic wind data used for its study of wind integration. The company recognizes the importance of using high-quality wind data, and consequently indicated at the workshop that it would thoughtfully review the wind data in an effort to address the questions raised. As stated at the workshop, the wind data used for the study were provided by 3TIER. 3TIER provided these data for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for purchase agreement. The 43 wind project locations are given as Attachment No. 3 to comments filed by Idaho Power with the IPUC on December 22, 2010[3]. It is important to note that 3TIER did not select from the more than 32,000 existing or hypothetical wind project sites used for the Western Wind and Solar Integration Study (WWSIS), but instead pulled new time series directly from the WWSIS gridded model data set precisely at the 43 locations requested by Idaho Power. **Thus, the geographic diversity of the synthetic wind data provided by 3TIER is representative of the geographic diversity for projects proposed to Idaho Power.**

3TIER also provided a synthetic day-ahead forecast for the wind generation time series. In providing this forecast, 3TIER notes that a bias found in the forecast during completion of the WWSIS was corrected on a site-by-site basis for the Idaho Power wind study, as opposed to the regional bias correction used for the WWSIS. The site specific correction is preferable to the regional correction because it mimics real forecasting practice, where project data at each site would be used to eliminate long-term bias from the forecast. With respect to accuracy of the synthetic day-ahead forecast, 3TIER reports that hourly wind speed forecast errors for ten operational sites in Idaho or neighboring states were compared to similarly calculated errors for the synthetic day-ahead forecast. 3TIER reports that this comparison yielded values for mean absolute error and root mean squared error for the synthetic day-ahead forecast only about 15% higher than equivalent statistics for the real errors at the ten operational sites in the Idaho vicinity. **This result suggests that the error characteristics of the synthetic forecasts are very similar to those of actual wind forecasts.**

To validate the synthetic actual wind time series, 3TIER has completed validation reports describing the results of comparisons between the synthetic wind data and public tower data. The complete set of validation reports for the WWSIS can be found through the NREL website[4]. Five of the validation towers are located in Idaho. Review of these reports indicates that the synthetic actual wind time series capture the seasonal and diurnal wind cycles fairly well; however, the synthetic time series are consistently low biased, at a 3TIER-reported average level of about -1.2 m/s at the five validation sites. There is basis in suggesting that the low bias, while reducing the total production of modeled wind projects, would have minimal impact on the overall variability of the synthetic actual wind time series, and would consequently have little effect on the estimated integration cost.

[3] Idaho Power Comments, Idaho Public Utilities Commission Case GNR-E-10-04, Attachment No. 3.

[4] http://wind.nrel.gov/public/WWIS/ValidationReports/wwis_vrpts.html#vmap

However, Idaho Power recognizes the critical nature of the synthetic wind data used for the study, and will discuss this low bias further with the technical review committee it has formed.

Finally, the synthetic actual wind time series created for the WWSIS have been found to exhibit excessive ramping as described in the WWSIS final report and as reported by NREL[5]. The excessive ramping in the WWSIS wind data occurs because the mesoscale model used to generate the synthetic wind data was run in 3-day sections. Smoothing techniques were used to reduce the ramping across the seam at the end of each third day; however, 3TIER reports that excessive variability remains in the WWSIS wind data. 3TIER also reports that review of the synthetic actual wind time series data pulled for the Idaho Power study indicates similar excessive ramping, with ramps tending to be 1.5 to 2.0 times larger from two hours before to eight hours after the start of every third day. While Idaho Power intends to discuss this condition with its technical review committee, the company believes that only a small fraction of hours are affected, and that consequently the impacts on integration cost are likely small.

Idaho Power hopes that this follow-up helps to address questions on the wind data raised at the April 6 workshop. We value the questions and feedback received from workshop participants, and welcome remaining questions related to the wind data or other features of the wind study. We are planning a meeting with our technical review committee in early May, and are looking forward to the added value this group will bring to our effort.

Idaho Power, 1221 W Idaho Street, Boise, Idaho 83702
email:*IPC_Wind_Study@IdahoPower.com*

[5] http://www.nrel.gov/wind/integrationdatasets/pdfs/western/2009/western_dataset_irregularity.pdf

Appendix B. Wind data summaries

Table B1 Monthly and annual capacity factors (percent of installed nameplate capacity)

	Nameplate Wind		
Month	**800 MW**	**1,000 MW**	**1,200 MW**
January	30%	30%	30%
February	20%	20%	19%
March	31%	32%	32%
April	38%	38%	37%
May	24%	24%	24%
June	29%	29%	29%
July	20%	19%	19%
August	17%	17%	17%
September	18%	18%	18%
October	23%	23%	23%
November	36%	35%	35%
December	38%	38%	38%
Annual	27%	27%	27%

Note: Wind generation data for study provided by 3TIER.

This page left blank intentionally.

CERTIFICATE OF SERVICE
Docket No. UM 1610

I hereby certify that on February 4, 2013, I served the DIRECT TESTIMONY OF LISA A. GROW AND M. MARK STOKES ON BEHALF OF IDAHO POWER COMPANY upon all parties of record in this proceeding by electronic mail only as all parties have waived paper service.

Brittany Andrus
Public Utility Commission of Oregon
brittany.andrus@state.or.us

Stephanie S. Andrus
Department of Justice, Business Activities Section
stephanie.andrus@state.or.us
(workpaper disks served on party)

RNP Dockets
Renewable Northwest Project
dockets@rnp.org

Will K. Carey
Annala, Carey, Baker, et al., PC
wcarey@hoodriverattorneys.com

Melinda J. Davison
Davison Van Cleve PC
mjd@dvclaw.com
mail@dvclaw.com

Irion A. Sanger
Davison Van Cleve PC
ias@dvclaw.com

Oregon Dockets
PacifiCorp, d/b/a Pacific Power
oregondockets@pacificorp.com

Mary Wiencke
Pacific Power
mary.wiencke@pacificorp.com

J. Richard George
Portland General Electric Company
richard.george@pgn.com

Adam Bless
Public Utility Commission of Oregon
adam.bless@state.or.us

Bill Eddie
One Energy Renewables
bill@oneenergyrenewables.com

Megan Walseth Decker
Renewable Northwest Project
megan@rnp.org

Renee M. France
Oregon Department of Justice
Natural Resources Section
renee.m.france@doj.state.or.us

S. Bradley Van Cleve
Davison Van Cleve PC
bvc@dvclaw.com

Peter P. Blood
Columbia Energy Partners LLC
pblood@columbiaenergypartners.com

R. Bryce Dalley
Pacific Power
bryce.dalley@pacificorp.com

Randy Dahlgren
Portland General Electric Company
pge.opuc.filings@pgn.com

Thomas H. Nelson
nelson@thnelson.com

Diane Henkels
Cleantech Law Partners PC
dhenkels@cleantechlawpartners.com

John W. Stephens
Esler Stephens & Buckley
stephens@eslerstephens.com
mec@eslerstephens.com

Matt Krumenauer
Oregon Department of Energy
matt.krumenauer@state.or.us

Vijay A. Satyal
Oregon Department of Energy
vijay.a.satyal@state.or.us

Jeffery S. Lovinger
Lovinger Kaufmann LLP
lovinger@lklaw.com

Kenneth Kaufmann
Lovinger Kaufmann LLP
kaufmann@lklaw.com

OPUC Dockets
Citizens' Utility Board of Oregon
dockets@oregoncub.org

Mike McArthur
Association of Oregon Counties
mmcarthur@aocweb.org

G. Catriona McCracken
Citizens' Utility Board of Oregon
catriona@oregoncub.org

Robert Jenks
Citizens' Utility Board of Oregon
bob@oregoncub.org

Toni Roush
Roush Hydro Inc.
tmroush@wvi.com

Elaine Prause
Energy Trust of Oregon
elaine.prause@energytrust.org

John M. Volkman
Energy Trust of Oregon
john.volkman@energytrust.org

Loyd Fery
dlchain@wvi.com

Daren Anderson
Northwest Energy Systems Company LLC
da@thenescogroup.com

Donald W. Schoenbeck
Regulatory & Cogeneration Services, Inc.
dws@r-c-s-inc.com

David A. Lokting
Stoll Berne
dlokting@stollberne.com

David Tooze
City of Portland, Planning and Sustainability
david.tooze@portlandoregon.gov

Glenn Montgomery
Oregon Solar Energy Industries Association
glenn@oseia.org

James Birkelund
Small Business Utility Advocates
james@utiltiyadvocates.org

Mark Pete Pengilly
Oregonians for Renewable Energy Policy
mpengilly@gmail.com

Kathleen Newman
Oregonians for Renewable Energy Policy
kathleenoipl@frontier.com
k.a.newman@frontier.com

Peter J. Richardson
Richardson & O'Leary PLLC
peter@richardsonandoleary.com
(workpaper disks served on party)

Gregory M. Adams
Richardson & O'Leary
greg@richardsonandoleary.com
(workpaper disks served on party)

John Lowe
Renewable Energy Coalition
jravenesanmarcos@yahoo.com

Lisa Rackner
McDowell, Rackner & Gibson PC
dockets@mcd-law.com
(workpaper disks served on party)

Paul D. Ackerman
Exelon Business Services Company, LLC
paul.ackerman@constellation.com

Adam Lowney
McDowell, Rackner & Gibson PC
adam@mcd-law.com
(workpaper disks served on party)

Richard Lorenz
Cable Huston Benedict Haagensen & Lloyd LLP
rlorenz@cablehuston.com

Christa Bearry

Christa Bearry, Legal Assistant