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April 24, 2015

**VIA ELECTRONIC AND U.S. MAIL**

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

**Re: UM ____ – In the Matter of IDAHO POWER COMPANY Application for Approval of Solar Integration Charge**

Attention Filing Center:

Attached for filing is an electronic copy of Idaho Power Company's Application for Approval of Solar Integration Charge. Concurrent with this filing, we are making the following related filings:

1. Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term;
2. Application for Change in Resource Sufficiency Determination; and
3. Motion for Temporary Stay of its Obligation to Enter into New Power Purchase Agreements with Qualifying Facilities.

A copy of this filing has been served on all parties to Docket UM 1610 via electronic mail as indicated on the attached certificate of service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: UM 1610 Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document on the service list in Docket UM 1610 the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: April 24 2015

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**BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON**

**UM______**

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>Application for Approval of Solar Integration Charge. | **APPLICATION FOR APPROVAL OF SOLAR INTEGRATION CHARGE** |

## I. INTRODUCTION

Pursuant to OAR 860-001-0400(2) and ORS 758.535(2) Idaho Power Company ("Idaho Power") respectfully requests that the Public Utility Commission of Oregon ("Commission") issue an order modifying the terms and conditions under which Idaho Power enters into power purchase agreements with Qualifying Facilities ("QFs") pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Idaho Power requests that the Commission authorize Idaho Power to account for the costs of solar integration in both standard and negotiated QF contracts in accordance with Idaho Power's completed 2014 Solar Integration Study ("2014 Study") and pending 2015 Solar Integration Study ("2015 Study"). The Commission has already ordered utilities to account for the costs to integrate wind generation in their QF contracts. Idaho Power is asking for the same treatment for QF solar generation.

Over the past year, Idaho Power has experienced significant interest in solar QF development in both Idaho and Oregon, and the Company expects its QF solar penetration to soon exceed its wind QF penetration. The Company has signed contracts for 461 megawatts ("MW") of new QF solar generation[1], 60 MW of which are in Oregon;

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[1] On April 6, 2015, 4 of these QF solar contracts (141 MW total) were terminated for the projects' failure to post required Delay Security, which is a material breach of the agreements. This leaves

projects totaling another 1,326 MW have requested contracts, 245 MW of which are in Oregon.[2] For all solar projects located in Idaho, the Company was able to negotiate the inclusion of appropriate solar integration charges consistent with the costs identified in its 2014 Study. The 60 MW of signed contracts for QF solar generation in Oregon contain no integration charges. Given the rapid and substantial growth in solar development, the integration costs resulting from solar QF development are significant and must be accounted for if customers are to be held indifferent to solar QF generation.

The Company's 2014 Study was developed consistent with well-established principles for the integration of variable generation resources and with the advice and involvement of a Technical Review Committee ("TRC"), which, like the TRC for the Company's wind studies, provided input, review, and guidance for the Study. The Idaho Public Utilities Commission ("IPUC") recently approved an all-party stipulation agreeing to implement solar integration costs based upon the 2014 Study.[3] In that Stipulation, whose signatories included the Idaho Conservation League, Sierra Club, and Snake River Alliance, the parties agreed to implement the solar integration charges "as proposed and filed by Idaho Power."[4]

Given the sheer volume of solar development that the Company expects both in Oregon and Idaho, it is critical that the prices solar QFs pay reflect the true costs avoided by the utility. For this reason the Commission should take all steps to ensure appropriate prices, including the adoption of solar integration charges. Moreover, without a comparable solar integration charge in Oregon, and given the current disparity in the

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Idaho Power with 320 MW of QF solar projects currently under contract to come online in 2016, 60 of which is in Oregon.

[2] Idaho Power/106, Allphin/1-2 In the Matter of Idaho Power Company Application to Lower Standard contract Eligibility Cap and to Reduce the Standard Contract Term.

[3] *Idaho Power Co.*, Case No. IPC-E-14-18, Order No. 33227 (Feb. 11, 2015).

[4] *Id.* at 3.



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avoided cost prices, the Company is concerned that the rapid QF development that has occurred recently in Idaho will move to Oregon to take advantage of the higher prices. In fact, 60 MW of QF solar projects in Oregon have all ready executed fixed price, standard contracts without accounting for the costs of integrating intermittent solar generation onto the system. Adopting a consistent solar integration charge across Idaho Power's integrated system will result in more comparable prices between the states and reduce the incentive for QFs to game the system to take advantage of more advantageous contracting and pricing in Oregon.

Contemporaneously with this filing, the Company is requesting an order placing a temporary stay on Idaho Power's obligation under PURPA to enter into fixed-price, standard PURPA contracts with QFs. The Company's motion seeks a temporary stay until the Commission has fully addressed the Company's substantive filings requesting modifications to QF pricing and contracting. In the alternative, the Company's motion requests interim relief, in the form of lowering the eligibility cap, shortening the contract term, implementing a solar integration charge, and changing the Company's sufficiency/deficiency demarcation, pending the outcome of the Commission's investigation of these issues.

The Company notified Staff and the parties to docket UM 1610 of its intention to make this PURPA filing. As reflected in the *Stipulation re: Issues List* filed on February 20, 2015, in docket UM 1610, Staff and the parties supports the Company's decision to raise this issue in an Idaho Power-specific proceeding, rather than in Phase II of the generic PURPA investigation.

In support of this Application requesting the Commission to implement solar integration charges, Idaho Power presents its 2014 Solar Integration Study Report as Idaho Power/101, DeVol/1-36, filed contemporaneously with this Application. Also filed with this Application is the Direct Testimony of Michael J. Youngblood which sets forth the

Company's request and proposal to implement solar integration rates and charges based upon the costs identified in the 2014 Study. Idaho Power/201, Youngblood/1-16 sets forth the Company's requested solar integration charges in Schedule 86, which is consistent with the approve Idaho PUC Schedule 87 setting forth intermittent generation integration charges for the Company's Idaho jurisdiction.

Communications regarding this Application should be addressed to:

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|---|---|
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## II. BACKGROUND

### A. Status of Solar QF Development on Idaho Power's System.

Until recently, Idaho Power's tremendous amount of QF activity was due primarily to wind development. Between approximately 2006 and 2012, the Company added more than more 575 MW of QF wind to its portfolio, and today has 678 MW of wind operating on its system,[5] with an additional 50 MW of wind under contract in its Oregon jurisdiction. The tide has changed. Over the last year the Company has signed contracts with 461 MW of solar QF generation, and additional QF solar projects totaling 1,326 MW are actively seeking contracts and/or interconnection. If all of this solar generation is built, the

[5] This is comprised of approximately 577 MW of QF wind, and 101 MW of non-PURPA wind.

Company will have over 1,600 MW of QF solar projects on its system, and a grand total of over 2,400 MW of PURPA generation from all sources.[6]

## III. ARGUMENT

### A. Idaho Power's Solar Penetration is Sufficient to Approve an Integration Charge.

In Phase I of docket UM 1610 no party requested that the Commission approve an integration cost for solar resources, in light of the limited solar development at the time and the lack of any completed solar integration studies in the record.[7] Idaho Power had not yet completed its 2014 Solar Integration Study, and sought implementation only of wind integration charges at the time testimony was submitted for Phase 1. Additionally, Idaho Power had no QF solar projects under contract at that time. The Commission noted, however, that "we will revisit this issue in the future after more solar development occurs."[8] Given the rapid growth in solar QF capacity on Idaho Power's system, it is now necessary for the Commission to revisit this issue for Idaho Power and implement a solar integration charge.

Today Idaho Power has significant levels of solar penetration, a completed 2014 Solar Integration Study, and has initiated its second solar integration study in January of 2015. Idaho Power's solar QF development now exceeds the level of wind development that the Commission concluded was sufficient to account for integration costs.[9] When the Commission approved the wind integration costs in Order No. 14-058, Idaho Power had a total of 678 MW of wind on its system (577 MW of PURPA wind and an additional 101 MW

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[6] Idaho Power/101, Allphin/1, Idaho Power/105, Allphin/1-9, Idaho Power/106, Allphin/1-2, In the Matter of Idaho Power Company Application to Lower Standard contract Eligibility Cap and to Reduce the Standard Contract Term.

[7] Order No. 14-058 at 15.

[8] Order No. 14-058 at 15.

[9] Order No. 14-058 at 13.

from the Elkhorn Valley Wind Farm). The Company's solar penetration, based on projects that are either under contract or proposed, is expected to exceed 1,300 MW in 2016, or nearly double the level of wind penetration.

The rapid and unforeseen increase in solar QF development on Idaho Power's system makes timely approval of the integration charge essential. If Idaho Power is required to enter into long-term contracts with Oregon solar QFs that do not account for integration costs, customers will bear those costs for the life of the contract. For the currently proposed 245 MW of Oregon QF solar projects this could represent an overpayment of approximately $49 to $188 million over the life of all of the proposed QF solar contracts.[10]

### B. The Company has Completed its 2014 Solar Integration Study and Commenced its 2015 Solar Integration Study this Year.

The 2014 Study was designed to determine the economic impact on the Company's system resulting from the integration of intermittent solar generation. Due to the variable and intermittent nature of solar generation, Idaho Power must modify its system operations to successfully integrate solar power without impacting system reliability, similar to wind generation. Specifically, Idaho Power, or any electrical system operator, must provide operating reserves from resources that are capable of increasing or decreasing dispatchable generation on short notice to offset changes in non-dispatchable solar generation. As a result, these resources cannot be economically dispatched to their fullest capability, resulting in higher power supply costs. The Study quantifies these higher power supply costs and determines an appropriate integration charge on a dollar per MWh basis.

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[10] Idaho Power current has 320 MW of QF solar that remains under contract. The associated solar integration charge for penetration levels of 400 MW through 1,500 MW starts at approximately $3.12/MWh for penetration levels of 401 MW through 500 MW, and escalates to $18.29 for penetration levels of 1,401 MW through 1500 MW. Idaho Power/200, Youngblood/1-10.

The 2014 Study was conducted in a manner comparable to the Company's wind integration study and is consistent with industry standards. The conduct of the study was guided by two key industry documents: *Principles for Technical Review (TRC) Involvement in Studies of Variable Generation Integration into Electrical Power Systems*, produced by the National Renewable Energy Laboratory ("NREL") and the Utility Variable-generation Integration Group; and *The Evolution of Wind Power Integration Studies: Past, Present, and Future*, which was authored by five NREL researchers considered to be at the forefront of the study of renewable integration and was published by the Institute of Electrical and Electronics Engineers.

In general terms, the cost of integrating solar generation increases as the amount of solar generation on the electrical system increases. The 2014 Study determined solar integration costs for four solar build-out scenarios at installed capacities of 100 MW, 300 MW, 500 MW, and 700 MW. The Company is currently conducting a second study, (the 2015 Study), which will include penetration levels beyond 700 MW. The 2014 Study utilized geographically dispersed build-out scenarios with solar generation located across the Company's service territory at Parma, Boise, Grand View, Twin Falls, Picabo, and Aberdeen. For each penetration level the Company conducted two simulations: a test case that required dispatchable generators to carry extra capacity in reserve to allow them to respond to unplanned solar variations, and a base case with no extra capacity requirement. The cost difference between these two cases forms the basis of the integration charge.

Given that the Company's expected solar penetration already exceeds these initial build-out scenarios, the Company has extrapolated the Study's results to determine solar integration costs for build-out scenarios consistent with the Company's current expected penetration. The 2015 Study will account for the level of solar penetration the Company is currently anticipating.

Consistent with the Commission's requirements for wind integration studies, the Company's solar integration studies utilize a TRC, with the purpose of providing input, review, and guidance for the studies. The TRC for the 2014 Study included Staff from both the Commission and the IPUC, as well as representatives from the University of Idaho, the Renewable Northwest, the Idaho National Laboratory, and the City of Boise.

While the study of solar integration is relatively young, especially when compared to the study of wind integration, the Company was able to verify the reasonableness of its results through comparisons to studies that have been conducted for other utility systems.

### C. The IPUC Recently Approved the Company's Proposed Solar Integration Costs.

On July 1, 2014, Idaho Power filed with the IPUC an application to implement solar integration charges for Idaho QFs. The application was based on the 2014 Study, the same Study presented here. The parties to the Idaho proceeding entered into a settlement stipulation that requested approval of the Company's proposed solar integration charges as filed. The agreement also included several terms related to the Company's 2015 Study, which was commenced in January 2015. The IPUC approved the settlement stipulation on February 11, 2015. The IPUC "commend[ed] the parties for agreeing to put a [solar integration charge] in place while a second study is conducted."[11] In the event that solar penetration exceeded the Study's 700 MW level, the IPUC directed Idaho Power "utilize the same process/methodology that it applied in its first study to extrapolate integration charges as solar penetration increases."[12] The stipulation was signed by representatives of several environmental groups, including the Sierra Club.

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[11] *Idaho Power Co.*, Case No. IPC-E-14-18, Order No. 33227 at 5 (Feb. 11, 2015).

[12] *Idaho Power Co.*, Case No. IPC-E-14-18, Order No. 33227 at 5-6 (Feb. 11, 2015).

Here, the Company requests approval of the same solar integration costs agreed to by the parties and approved by the IPUC. Consistency across jurisdictions will lessen the opportunity for regulatory arbitrage based on disparate avoided cost prices.

## IV. CONCLUSION

For all of the reasons stated above, Idaho Power requests that the Commission approve the Company's proposed solar integration costs for QF contracts.

Respectfully submitted this 24th day of April, 2015.

**McDowell Rackner & Gibson PC**

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UM ______**

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|---|---|
| In the Matter of | ) |
| IDAHO POWER COMPANY | ) |
| Application for Approval of Solar Integration Charge. | ) |

**IDAHO POWER COMPANY**

**DIRECT TESTIMONY**

**OF**

**PHILIP B. DeVOL**

**April 24, 2015**

**Q. Please state your name and business address.**

A. My name is Philip B. DeVol 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 a Senior Planning Analyst.

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

A. In May of 1989, I received a Bachelor of Science Degree in Mathematics from Miami University in Oxford, Ohio. I then received a Master of Science Degree in Biostatistics from the University of Michigan in May of 1991.

**Q. Please describe your work history at Idaho Power.**

A. I began my employment with Idaho Power in 2001 in the Company's Water Management Department, where my responsibilities included modeling of the Idaho Power hydroelectric system for the Integrated Resource Plan ("IRP") and relicensing studies.

I transferred in 2005 to the Power Supply Planning Department at Idaho Power, where I remain employed as a Senior Planning Analyst. My responsibilities in Power Supply Planning have been varied, and have included several studies of renewable integration. My duties have included project management for the most recent (2013) Idaho Power wind integration study, and Idaho Power's first solar integration study completed in 2014.

I have been involved in regional and national proceedings related to the study of wind integration. I participated in methodology discussions for the 2007 Wind Integration Action Plan produced by the Northwest Wind Integration Forum. I have attended numerous Utility Wind Integration Group ("UWIG") workshops, and presented at UWIG workshops in Oklahoma City in 2006, Portland, Oregon, in 2007, and San Antonio, Texas in 2014. I also presented to the Idaho Wind Working Group at its September 2011 meeting. In November of 2013, I presented at a Centre for Energy Advancement through Technological Innovation workshop focused on forecasting uncertainties for renewable energy supply.

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

A. The purpose of my testimony is to describe Idaho Power's solar integration study ("Study" or "2014 Study" or "Solar Study") and to provide the results. The 2014 Solar Integration Study Report ("Study Report") is attached hereto as Idaho Power/101, DeVol/1-36. The Study Report was completed on June 16, 2014.

**Q. Can you provide a high level description or summary of the Company's 2014 Study?**

A. Yes. Electric power from solar generation resources exhibits greater variability and uncertainty than energy from conventional generation sources. The greater variability and uncertainty exhibited by solar resources requires an electric utility integrating solar to modify its operating practices by holding extra operating reserves on dispatchable generation resources. The effect of having to hold operating reserves on dispatchable resources is that the use of those resources is restricted and they cannot be economically dispatched to their fullest capability. The objective of the Study is to determine the costs of the operational modifications necessary to integrate solar generation.

The Company's Solar Study determined solar integration costs for four solar build-out scenarios at installed capacities of 100 megawatts ("MW"), 300 MW, 500 MW, and 700 MW. The Study utilized geographically dispersed build-out scenarios with solar generation located across the Company's service territory at Parma, Boise, Grand View, Twin Falls, Picabo, and Aberdeen. Pages 6 and 7 of the Study Report provide additional information regarding the build-out scenarios.

The Company initiated the Study with the formation of a Technical Review Committee ("TRC"), with the purpose of providing input, review, and guidance for the Study. In collaboration with the TRC, Idaho Power organized the Study into four primary steps: (1) data gathering and scenario development; (2) statistical-based analysis of solar characteristics; (3) production cost simulation analysis; and (4) study conclusions and results. The Study determined solar integration costs through paired simulation of Idaho Power's system at each solar build-out scenario. Each pair of simulations consists of a test case in which extra capacity in reserve is required of dispatchable generators to allow them to respond to unplanned solar variations and a base case in which no extra capacity in reserve is required. The solar integration costs indicated by the simulations are provided below. These costs are also found in Table 2, page 3 of the Study Report, as well as Table 8 and Table 9 on page 15 of the Study Report.

**Average Integration Cost Per MWh**

**(2014 cost and dollars)**

| **Build-out Scenarios** | **0-100 MW** | **0-300 MW** | **0-500 MW** | **0-700 MW** |
|---|---|---|---|---|
| **Integration Cost** | **$0.40** | **$1.20** | **$1.80** | **$2.50** |

**Incremental Integration Cost Per MWh**

**(2014 cost and dollars)**

| **Penetration Level** | **0-100 MW** | **100-300 MW** | **300-500 MW** | **500-700 MW** |
|---|---|---|---|---|
| **Integration Cost** | **$0.40** | **$1.50** | **$2.80** | **$4.40** |

**Q. What is the difference between Average Integration Cost and Incremental Integration Cost?**

A. As explained in the Study Report, the cost to integrate solar generation onto the Company's system increases with increasing penetration levels. The Average Integration Cost as shown above, reports an average cost per megawatt hour ("MWh") that applies to all of the four solar build-out scenarios modelled in the Study. Conversely, the Incremental Integration Costs indicates the cost of integrating solar generation as it would be assigned separately for the individual build-out scenarios.

**Q. When did Idaho Power initiate the 2014 solar integration study?**

A. The official Study kick-off was on August 15, 2013, with the first meeting of the TRC.

**Q. What is the TRC?**

A. The TRC was formed during the summer of 2013 with the purpose of providing input, review, and guidance for the Study. It is made up of participants from outside of Idaho Power that have an interest and/or expertise in the integration of intermittent resources onto utility systems. The TRC consisted of: Brian Johnson from the University of Idaho; Jimmy Lindsay from the Renewable Northwest Project ("RNP") (now with Portland General Electric); Kurt Myers from the Idaho National Laboratory; and Paul Woods with the City of Boise (now self-employed as a consultant). In addition, Staff from both the Idaho and Oregon commissions participated in the Study. Rick Sterling from the Idaho Public Utilities Commission Staff and Brittany Andrus and John Crider from the Public Utility Commission of Oregon Staff participated throughout the Study. Although Mr. Lindsay left RNP, he continued to participate as a TRC member. Cameron Yourkowski was designated by RNP as Mr. Lindsay's replacement for the TRC. Similarly, Mr. Woods continued to serve as a board member after he left employment with the City of Boise.

**Q. How was the 2014 Study conducted?**

A. The conduct of the Study was guided by two documents that were shared with and discussed with the TRC. *Principles for Technical Review (TRC) Involvement in*

*Studies of Variable Generation Integration into Electrical Power Systems* was produced by the National Renewable Energy Laboratory ("NREL") and Utility Variable-generation Integration Group ("UVIG"). The NREL/UVIG principles document provides guidance in defining the important role of the TRC in the Study. The second report, *The Evolution of Wind Power Integration Studies: Past, Present, and Future*, was authored by five NREL researchers considered to be at the forefront of the study of renewable integration and was published by the Institute of Electrical and Electronics Engineers ("IEEE"). This report is used as the roadmap for Idaho Power's solar integration study. Even though the report was written from the perspective of wind integration, the principles remain the same for solar integration. Solar, like wind, is variable and uncertain and, consequently, the system of dispatchable resources has to be operated differently in order to successfully integrate the generation without compromising reliability.

**Q. What process did the 2014 Study following?**

A. The Study generally followed the process outlined in the IEEE report, which includes the following steps:

Step 1: Data gathering and scenario development;

Step 2: Study analysis

Step 2(a): Statistical-based analysis of solar characteristics;

Step 2(b): Production cost simulation analysis;

Step 2(c): Reliability assessment;

Step 3: Study conclusions and results.

**Q. Did the TRC agree with and participate in this process?**

A. Yes. Idaho Power comprehensively walked through both guiding documents, as well as the steps outlined above, with the TRC. Additionally, the importance of the guiding documents was emphasized to participants at a May 1, 2014, public workshop. The

TRC was extensively involved in Step 1-- data gathering and scenario development. The TRC was integrally involved with the identification of suitable sources of solar production data, as well as discussions leading to the development of scenarios to be studied. The TRC had a leading role in advising on the use of wavelet variability modelling to transform point-source solar data to meaningful production data for a solar farm. This technique is described on page 8 of the Study Report. The TRC's counsel with respect to Idaho Power's use of the wavelet technique was important and needed.

**Q. Can you further describe how the 2014 Study progressed to completion?**

A. Yes. As noted in the IEEE report, one of the primary tasks of Step 1 is to develop the solar resource data that is needed to model future power output. This task proved particularly challenging for the Study. The solar build-out scenarios consider solar plants at six locations in southern Idaho: Parma, Boise, Grand View, Twin Falls, Picabo, and Aberdeen. The Study was able to obtain solar data from the U.S. Bureau of Reclamation AgriMet network at the desired five-minute time step for all locations except Grand View. NREL maps indicate the area surrounding Grand View and Glenns Ferry has the highest annual solar intensity in the state. For this reason, Idaho Power and the TRC have felt it is important to model a solar plant at Grand View. Obtaining five-minute solar data for Grand View has required the acquisition of data from SolarAnywhere, which is a web-based service from Clean Power Research providing satellite-derived solar irradiance data. The Study did not receive data for Grand View from SolarAnywhere until April 2014, causing delay in the Study schedule.

With the acquisition of data for the Grand View area, the Study progressed into the statistically-based analysis of solar characteristics. The intent of this analysis is to translate the variability and uncertainty present in the solar data to an incremental reserve requirement. The NREL authors of the IEEE report describe this task as an analysis to determine the increase in ancillary services required by a given solar scenario, where NREL defines ancillary services as services that help grid operators maintain balance on electric power systems. The next step in the Study was to take the increase in reserve requirement, or ancillary services, from step 2.a for any given solar scenario and to input it into the Study's production cost simulations to determine the cost of carrying increased ancillary services, step 2.b.

It was also at this point that the decision was made to modify the build-out scenarios to include higher levels of solar penetration. This decision was based primarily upon the increase in proposed solar projects for Idaho Power's system that outpaced the highest penetration level initially contemplated by the Study. Initially, the Study planned to analyze four build-out scenarios: dispersed 50 MW; dispersed 100 MW; dispersed 300 MW; and clustered 300 MW. I should note that the build-out scenarios are described as dispersed in the sense that their solar capacity consists of utility-scale power plants spread out over several (or all) of the six data locations in southern Idaho; the use of dispersed as a descriptor does not represent build-out scenarios of small-sized distributed generation. However, with the emergence of over 500 MW of solar generation seeking contracts with the Company, the need to study beyond the 300 MW level became apparent. Consequently, in a May 16, 2014, meeting, the Company communicated to the TRC the following four revised build-out scenarios: dispersed 100 MW; dispersed 300 MW; dispersed 500 MW; and dispersed 700 MW. The proposal to study these revised build-out scenarios was not controversial with the TRC, and they recognized the need to study expanded build-outs given the potential development described in the Company's May 13, 2014, filing in Case No. IPC-E-14-09 seeking a suspension of its obligation to purchase Public Utility Regulatory Policies Act of 1978 solar generation until the Study could be completed.

**Q. How was the statistically-based analysis of solar characteristics conducted?**

A. Based on Idaho Power's review of the solar data from its build-out scenarios, the Company focused its analysis of variability and uncertainty in the context of hour-ahead system scheduling. In this context, the hour-ahead system scheduler requires for a given operating hour a forecast for hourly average solar production, as well as forecasts for lower and upper bounds on instantaneous solar production. The Study assumes these forecasts for solar production need to be delivered to the system scheduler 45 minutes prior to the start of the operating hour being scheduled. With this information, the system can be scheduled according to the forecast for hourly average solar production and, importantly, also be scheduled in a manner allowing dispatchable generators to respond during the operating hour if solar production varies from the forecasted level toward either bound. Discussion of the regional electric power market and the Company's hour-ahead scheduling activities is included in pages 8 through 11 in the Study Report.

The hour-ahead hourly average solar production forecast developed for the Study is based on persistence, with an adjustment to account for the known changes in the sun's position. The lower and upper bounds on solar production are established as percentages of the hourly average solar production forecast, with adjustments made to narrow the bounds in response to periods of stable production. The logic developed to make these adjustments to the bounds was well received by the TRC, and has been described in TRC meetings as an example of a "learning" or "adaptive" model. The techniques followed to develop the hour-ahead solar production forecast and the accompanying bounds on instantaneous solar production were described to the TRC in a May 16, 2014, meeting.

**Q. What was the next step in the Study process?**

A. Step 2(b) was the production cost simulations. As described earlier in my testimony, the Study followed the conventional design of simulating two scenarios: a test scenario having incremental amounts of solar-caused reserve and a base scenario without the incremental reserve.

**Q. Could you describe the TRC involvement in the later stages of the Study?**

A. Yes. The TRC schedule, including the meeting dates and agenda items, is set forth on page 23 of the Study Report. The final formal TRC meeting was held on May 29, 2014. The intent of this meeting was to provide a relatively high-level description of the production cost simulations. In response to TRC expressions of interest in understanding how reserves influence system operations, Idaho Power also provided an overview of operating reserves. The discussion during the May 29 meeting focused on an explanation of the production cost model, a demonstration of the input of solar-caused reserve requirements to the production cost model, and an illustration of the effect of the solar-caused reserves on simulated operations. The Company acknowledged the complexity of the production cost simulations to the TRC. There were expressions from some in the TRC to explore in further detail, specifically to explore additional water year types (e.g., low and high water year types). However, the Company expressed that for this phase of the Study further exploration of additional water years was not necessary, emphasizing the need for a timely completion of the Study. Finally, the May 29 meeting ended with a presentation of the integration costs found by the production cost simulations, which at the time were considered preliminary.

A draft study report was circulated to the TRC on June 2, 2014. The Company indicated in its correspondence with the TRC on June 2 the continued objective to complete the Study by mid-June. The TRC members submitted comments on the process and the Study. Several TRC members identified items for further study, which are listed in the Study Report on page 18.

**Q. Can you describe the results of the Study?**

A. Yes. The objective of the Study was to determine the costs of the operational modifications necessary to integrate solar generation. The integration costs are driven by the need to carry extra capacity in reserve to allow bidirectional response from dispatchable generators to unplanned variations in solar production. The simulations performed for the Study indicate the following costs associated with holding the extra capacity in reserve. The provided costs are the costs to integrate solar production for the calendar year 2014, and are not costs averaged or levelized over the life of the solar power plant.

**Average Integration Cost Per MWh**

**(2014 cost and dollars)**

| Build-out Scenarios | 0-100 MW | 0-300 MW | 0-500 MW | 0-700 MW |
|---|---|---|---|---|
| Integration Cost | $0.40 | $1.20 | $1.80 | $2.50 |

**Incremental Integration Cost Per MWh**

**(2014 cost and dollars)**

| Penetration Level | 0-100 MW | 100-300 MW | 300-500 MW | 500-700 MW |
|---|---|---|---|---|
| Integration Cost | $0.40 | $1.50 | $2.80 | $4.40 |

**Q. Are the results of Idaho Power's Solar Study consistent with those conducted for other utility systems?**

A. Yes. Idaho Power's Study results fall within the range reported by other utilities for the cost of integrating solar generation. While the study of solar integration is relatively young, especially when compared to the study of wind integration, I am aware of solar integration studies that have been conducted for other utility systems. Notable among these studies are a 2011 solar integration study for the NV Energy system, a 2012 solar integration study for Arizona Public Service ("APS"), and a 2014 solar integration study for Tucson Electric Power ("TEP"). The NV Energy study reports integration costs ranging from \$3.00 to \$8.00 per megawatt-hour ("MWh") of integrated solar generation. The APS study reports integration costs ranging from about \$1.50 to \$3.00 per MWh of integrated solar generation. The TEP study reports an integration cost of \$5.20 per MWh.

**Q. Has Idaho Power initiated a second solar integration study?**

A. Yes, and in fact the Company is currently in the process of developing a new solar integration study. Idaho Power, as referenced and anticipated in the stipulation approved by the Idaho PUC in Case No. IPC-E-14-18, the Company initiated a second solar integration study in January 2015. That study is being led by Ron Schellberg, Engineering Leader, Customer Operations and Planning, for Idaho Power. The 2015 solar integration study will utilize a Technical Review Committee ("TRC") which includes members with expertise in solar generation, variable energy integration and electrical grid operations. In addition, the TRC includes participation from both the Idaho and Oregon Commission Staff. My understanding is that a TRC was formed and this second solar integration study is proceeding with the intent of having final results within one year of its initiation. The second study will include penetration levels beyond 700 MW, which was the highest penetration level included in the 2014 Study.

**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 Philip B. DeVol

2014 Solar Integration Study Report

April 24, 2015

An IDACORP Company

# Solar Integration Study Report

June 2014

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# EXECUTIVE SUMMARY

Electric power from solar photovoltaic resources exhibits greater variability and uncertainty than energy from conventional generators. The greater variability and uncertainty exhibited by solar photovoltaic resources require an electric utility integrating solar to modify the operation of dispatchable generating resources. The modified operation involves the sub-optimal dispatch of generators to carry extra capacity in reserve for responding to unplanned solar excursions.

The objective of the Idaho Power solar integration study is to determine the costs of the operational modifications necessary to integrate solar photovoltaic plant generation. This study determines these costs for four solar build-out scenarios provided in Table 1.

**Table 1**
Solar build-out scenarios studied

| | Installed Capacity of Solar Build-Out Scenarios | | | |
|---|---|---|---|---|
| **Site** | **100 megawatts (MW)** | **300 MW** | **500 MW** | **700 MW** |
| Parma, ID | 10 | 30 | 50 | 100 |
| Boise, ID | 20 | 60 | 100 | 100 |
| Grand View, ID | 20 | 60 | 100 | 150 |
| Twin Falls, ID | 20 | 60 | 100 | 100 |
| Picabo, ID | 10 | 30 | 50 | 100 |
| Aberdeen, ID | 20 | 60 | 100 | 150 |
| **Total MW** | **100** | **300** | **500** | **700** |

The study determines solar integration costs through paired simulations of the Idaho Power system for each solar build-out scenario. Each pair of simulations consists of a test case in which extra capacity in reserve is required of dispatchable generators to allow them to respond to unplanned solar excursions and a base case in which no extra capacity in reserve is required. The solar integration costs indicated by the simulations are provided in Table 2.

**Table 2**
Average integration cost per MWh for solar build-out scenarios

| | **0-100 MW** | **0-300 MW** | **0-500 MW** | **0-700 MW** |
|---|---|---|---|---|
| **Integration cost** | $0.40/MWh | $1.20/MWh | $1.80/MWh | $2.50/MWh |

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest $0.10.

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# ACKNOWLEDGMENTS

Idaho Power acknowledges the important contribution of the Technical Review Committee (TRC) in this solar integration study. The TRC has been involved from the study outset in August 2013 and has provided substantial guidance. Idaho Power especially thanks the TRC for the collegial discussions of solar integration during TRC meetings. These discussions helped shape the study methods followed and are consistent with the TRC guidelines as provided by the Utility Variable-Generation Integration Group (UVIG) and the National Renewable Energy Laboratory (NREL) (UVIG and NREL n.d.). The following are members of the Idaho Power solar integration study TRC:

- Brian Johnson, University of Idaho
- Jimmy Lindsay, Portland General Electric (formerly of Renewable Northwest Project)
- Kurt Myers, Idaho National Laboratory
- Paul Woods, (formerly of City of Boise)
- Cameron Yourkowski, Renewable Northwest Project (replacing Jimmy Lindsay)

Staff from the Idaho and Oregon regulatory commissions have participated as observers throughout the process. The following staff have been observers of the process:

- Brittany Andrus, Public Utility Commission of Oregon (OPUC) staff
- John Crider, OPUC staff
- Rick Sterling, Idaho Public Utilities Commission (IPUC) staff

TRC members and regulatory observers serve either voluntarily or are paid by their own employers and receive no compensation from Idaho Power. The company is grateful for the TRC's time spent supporting the study and recognizes this support has led to a better study.

# INTRODUCTION

Electric power from solar photovoltaic resources exhibits greater variability and uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when their other generators are called on to integrate photovoltaic solar plant generation. These costs occur because power systems are operated less optimally in order to successfully integrate solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the modifications it must make to power system operations to integrate solar photovoltaic power plant generation connecting to its system. The objective of this solar integration study is to determine the costs of the operational modifications necessary to integrate solar plant generation. This report is intended to describe the operational modifications and the resulting costs.

In collaboration with the TRC, Idaho Power organized the study into four primary steps:

1. Data gathering and scenario development
2. Statistical-based analysis of solar characteristics
3. Production cost simulation analysis
4. Study conclusions and results

These steps were formulated based on an article published by the Institute of Electrical and Electronics Engineers (IEEE) describing methods for studying wind integration (Ela et al. 2009). While the IEEE article, which was authored by leading researchers at the NREL, was written from the perspective of studying grid integration of wind generation, the principles underlying the study of wind integration are readily transferrable to the study of solar integration. Both wind and solar bring increased variability and uncertainty to power system operation, and a key objective of an integration study for each is to understand how variability and uncertainty lead to impacts and costs.

# Data Gathering and Scenario Development

A critical element of the solar integration study is the solar generation data developed for the studied solar build-out scenarios. For Idaho Power's solar integration study, the solar build-out scenarios in Table 3 were studied.

**Table 3**
Solar build-out scenarios studied

| | Installed Capacity of Solar Build-Out Scenarios | | | |
|---|---|---|---|---|
| **Site** | **100 megawatts (MW)** | **300 MW** | **500 MW** | **700 MW** |
| Parma, ID | 10 | 30 | 50 | 100 |
| Boise, ID | 20 | 60 | 100 | 100 |
| Grand View, ID | 20 | 60 | 100 | 150 |
| Twin Falls, ID | 20 | 60 | 100 | 100 |
| Picabo, ID | 10 | 30 | 50 | 100 |
| Aberdeen, ID | 20 | 60 | 100 | 150 |
| **Total MW** | **100** | **300** | **500** | **700** |

The above build-out scenarios were developed in consultation with the TRC to represent geographically dispersed build-outs of solar power plant capacity. The importance of geographic dispersion in reducing integration impacts and costs is discussed in greater detail later in this report. The sites from the solar build-out scenarios are part of the established United States (U.S.) Bureau of Reclamation (USBR) AgriMet Network (AgriMet). AgriMet is a satellite-based network of automated agricultural weather stations operated and maintained by the USBR. The stations are located in irrigated agricultural areas throughout the Pacific Northwest and are dedicated to regional crop water-use modeling, agricultural research, frost monitoring, and integrated pest and fertility management. The six sites are spread across southern Idaho and cover over 220 miles from east to west (Figure 1). Sites represent elevations ranging from 2,300 feet to 4,900 feet (Table 4).


**Figure 1**
AgriMet sites used in IPC's solar integration study

**Table 4**
AgriMet site latitude, longitude, and elevation used in IPC's solar integration study

| Station | Latitude (N) | Longitude (west) | Elevation (feet) | Elevation (meter) |
|---|---|---|---|---|
| Parma | 43.18 | 116.93 | 2,305 | 702 |
| Boise | 43.60 | 116.18 | 2,720 | 829 |
| Grand View | 42.91 | 116.06 | 2,580 | 786 |
| Twin Falls | 42.55 | 114.35 | 3,920 | 1,195 |
| Picabo | 43.31 | 114.17 | 4,900 | 1,494 |
| Aberdeen | 42.95 | 112.83 | 4,400 | 1,341 |

All data used in the integration study are 5-minute interval global horizontal irradiance data from each site. Idaho Power worked directly with the USBR Pacific Northwest Region AgriMet manager to obtain data for the sites. AgriMet data was augmented with data from the University of Oregon Solar Radiation Monitoring Laboratory when AgriMet data was incomplete. The use of high-resolution (5-minute interval) data is critical to characterizing the variability of solar.

An alternative data-gathering approach was necessary for the Grand View site, for which only 15-minute data was available. To acquire 5-minute data for Grand View, Idaho Power contracted with SolarAnywhere to provide high-resolution modeled solar data. SolarAnywhere uses hourly satellite images processed using the most current algorithms developed and maintained by Dr. Richard Perez at the University at Albany (SUNY). The algorithm extracts cloud indices from the satellite's visible channel using a self-calibrating feedback process capable of adjusting for arbitrary ground surfaces. The cloud indices are used to modulate physically-based radiative transfer models describing localized clear-sky climatology.

## Wavelet-Based Variability Model

AgriMet solar data represents conditions at a single point. To better reflect conditions at a solar plant size, the TRC recommended the use of the wavelet-based variability model (WVM) developed by Dr. Matt Lave of Sandia National Labs (Lave et al. 2013a,b). WVM is designed for simulating solar photovoltaic power plant output given a single irradiance point-sensor time series. The application of the WVM to the point-sensor time series produces a variability reduction reflecting an upscaling of the point-source data to a solar plant-sized area. Research and use into the WVM showed it is not useable at time steps (intervals) greater than 10 minutes and that times steps greater than 5 minutes may under-represent variability in dispersed systems.

## Solar Plant Characteristics

This study assumes solar plants comprising the build-out scenarios occupy 7 acres per MW of installed capacity. Solar plant sizes in the build-out scenarios, as well as figures presented for solar generation, are in terms of AC (alternating current) MW. Photovoltaic panels are assumed to be of standard crystalline silicon manufacture. Panels are assumed to be fixed south facing and tilted at latitude. While panel orientation and tracking capability are key factors in the determination of avoided costs, these attributes are of lesser importance with respect to the variability and uncertainty driving integration costs. Illustrations and data summarizing the solar production of the studied build-outs are provided in Appendix 1.

# STATISTICAL-BASED ANALYSIS OF SOLAR CHARACTERISTICS

The intent of the statistical-based analysis of solar characteristics is to translate solar's variability and uncertainty into an increased requirement for ancillary services, where ancillary services in this context relate to the electrical system's capacity to maintain a balance between customer demand and generation. For the study, the variability and uncertainty associated with solar generation were viewed from the perspective of hour-ahead scheduling of the Idaho Power system. There are three critical elements from this perspective:

1. Forecast hourly average solar production for the operating hour being scheduled
2. Lower bound for instantaneous solar production during the operating hour
3. Upper bound for instantaneous solar production during the operating hour

From the perspective of real-time generation scheduling in practice, the lower and upper bounds would be considered an interval or band on solar production, and the occurrence of solar production outside the interval at any moment during the hour is highly unlikely. Moreover, while under prudent operating practices the occurrence of solar production outside the lower and upper bounds should be infrequent, occasional solar excursions outside these bounds do not necessarily bring about events for which system reliability is jeopardized. Conversely, the occurrence of solar production within the interval between the lower and upper bounds would be considered likely enough to warrant the scheduling of dispatchable generators to have capacity to respond if solar production varies during the hour from the forecasted level of production toward either bound.

An understanding of Idaho Power's participation in the regional electric power market is critical to this approach. Idaho Power primarily participates in the Pacific Northwest's Mid-Columbia (Mid-C) electric power market. The company participates in the Mid-C market at multiple time frames ranging from years or months in advance for long-term operations planning to hour-ahead generation scheduling in real time.

The focus for this study is the real-time market activities occurring as part of hour-ahead system scheduling. The study assumes hour-ahead schedulers require the delivery of forecast hourly average solar production and the above-described lower and upper bounds 45 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is assumed binding, and unexpected conditions occurring during the operating hour being scheduled must be managed by changing production for Idaho Power-owned dispatchable resources.

Idaho Power recognizes efforts to establish intra-hour trading in U.S. electric power markets. However, company experience has shown the intra-hour market to be currently highly illiquid. Therefore, the last opportunity to participate in the electric power market is at the hour-ahead time frame; unexpected conditions occurring during the operating hour (e.g., unexpected levels of solar production) cannot be managed through market activity at this time.

## Hour-Ahead Solar Production Forecast

The hour-ahead solar production forecast was developed to predict hourly average solar production for the operating hour being scheduled and lower and upper bounds for instantaneous solar production during the operating hour. This forecast was developed using a persistence-based technique that relies on observations from the previous hours to inform the model about subsequent forecast hours. The results of the forecast are a unique set of values (average production, upper bound, and lower bound) for every hour in the year.

The average production forecast is derived based on two components. The first component accounts for the amount of generation the system observed from the last 20 minutes of the preceding forecast hour. This component is referred to as the persistence component. The persistence component serves as a mechanism to increase the average forecast during times of high solar production and decrease the average forecast during times of low solar production. These increases and decreases are made to the forecast hourly and account for changes in solar production. In general, the shape of the production from a solar photovoltaic system increases before solar noon and decreases after solar noon. Every day of the year has a unique clear-day shape. Generally, summer days are long and have a high potential for solar production while winter days are shorter and have less potential. The forecast accounts for the uniqueness of each day by applying an hourly shaping factor. This shaping component, or shaping factor, is a unique value for every hour in the year. The shaping component is a ratio of the maximum solar potential of the forecast hour divided by the maximum potential of the previous hour. By utilizing a shaping component and a persistence component, the average production forecast captures hourly changes due to atmospheric conditions and seasonal effects. Table 5 provides the forecast error for the hour-ahead solar production forecast.

**Table 5**
Forecast error for the hour-ahead solar production forecast

| | 100 MW | 300 MW | 500 MW | 700 MW |
|---|---|---|---|---|
| **Absolute Mean Hourly Error (MW)** | 1.9 | 5.8 | 9.6 | 12.2 |

Table 5 reports the absolute mean error calculated on an hourly basis for water year 2012. The absolute hourly error is calculated as the absolute difference between the average hourly forecast and the average of 5-minute observed production data for a given hour. It is noted that the 5-minute observed production data is the output of the WVM. The absolute mean hour errors range from 1.9 MW to 12.2 MW for the 100 MW and 700 MW build-out scenarios, respectively.

The lower bound for instantaneous solar production during the operating hour is forecasted as a percentage of the forecast average. In addition to the application of a percentage of average, the forecasting tool adjusts the lower bound forecast upward if the previous lower bound forecast was substantially too low. As a result of this secondary adjustment to the lower bound, the amount of incremental capacity held in reserve for the coming hour is reduced.

Similar to the lower bound, the upper bound for instantaneous solar production during the operating hour is forecasted as a percentage of the forecast average. In addition to the application of a percentage of average, the forecasting tool adjusts the upper bound forecast downward if the previous upper bound forecast was substantially too high. As a result of this secondary adjustment to the upper bound, the amount of decremental capacity held in reserve for the coming hour is reduced.

The upper and lower bounds are expected to capture the overwhelming majority of the variability observed in solar production. The upper bound is forecasted in such a way that only 2.5 percent of all observations exceed the upper bound for the entire year. Similarly, the lower bound is defined in such a way that only 2.5 percent of all observations are below the lower bound for the entire year.

The hour-ahead forecast for the average production, lower bound for instantaneous solar, and upper bound for instantaneous solar are calculated for every hour of the year. The amount of incremental capacity held in reserve for a given hour is calculated as the difference between the average production forecast and the lower bound. The amount of decremental capacity held in reserve for a given hour is calculated as the difference between the average production forecast and the upper bound. The total amount of capacity held in reserve for a given hour is used by the production cost model to calculate an integration cost. These reserve amounts, as well as the hour-ahead forecast for solar production, are input to the production cost model on an hour-by-hour basis, simulating the practice of real-time generation scheduling. Table 6 reports the forecasted amount of capacity held in reserve for water year 2012. Further explanation of the derivation of the hour-ahead solar production forecast and the lower and upper bounds is provided in Appendix 1.

**Table 6**
Forecasted incremental and decremental capacity held in reserve, water year 2012

| | Solar Build-Out Scenarios | | | |
|---|---|---|---|---|
| | **100 MW** | **300 MW** | **500 MW** | **700 MW** |
| Average hourly production (MW) | 17.0 | 52.5 | 89.0 | 118.2 |
| Average hourly capacity held in reserve—incremental (MW) | 4.9 | 13.2 | 21.2 | 27.6 |
| Average hourly capacity held in reserve—decremental (MW) | 4.9 | 15.2 | 26.9 | 34.8 |

# PRODUCTION COST SIMULATION ANALYSIS

The production cost simulations are designed to isolate the effects on the system associated with integrating solar. Under this design, production cost simulations are paired into a base case and test case, with all inputs to the paired simulations equivalent except an amount of capacity held in reserve in the test case simulation for integrating solar. The capacity held in reserve for the test case varies hourly depending on the hour-ahead forecast of solar production for a given operating hour and the lower and upper bounds on instantaneous solar production for the operating hour. The derivation of the hour-ahead solar production forecast and the lower and upper bounds is described in the previous section of this report.

## Design of Simulations

The production cost simulations are set up on a water-year calendar, where by convention a water year is from October 1 to September 30 and is designated by the calendar year in which the 12-month period ends. For example, water year 2013 is the 12-month period from October 1, 2012, through September 30, 2013.

The Idaho Power generating system as it exists at the time of issue of this report is assumed for the production cost simulations. Critical elements of the simulated system of generating resources include 17 hydroelectric facilities totaling 1,709 MW of nameplate capacity, 3 coal-fired facilities totaling 1,118 MW of nameplate capacity, and 3 natural gas-fired facilities totaling 762 MW of nameplate capacity. An illustration of the generating resources is provided in Appendix 1.

Idaho Power's critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the solar integration study modeling, the separate paths were combined to an aggregate path for off-system access. Purchases from the regional market are treated separately from sales to the regional market. Net firm purchases from the market are limited on a monthly basis to only the capacity and energy required to serve

Idaho Power's retail load. Sales to the market are limited to 500 MW in every hour. This profile of purchases and sales reflects the current capabilities of Idaho Power's transmission system.

Idaho Power is pursuing the development of the Boardman to Hemingway Transmission Project (B2H), which will increase Idaho Power's access to the Northwest to make additional purchases and sales. However, the transmission line's current in-service date is at least five years into the future. Previous integration studies have shown that unless there is a liquid capacity balancing market, B2H will not significantly impact the solar integration cost. Idaho Power is actively engaged in regional market discussions that could exist when B2H is completed, but the benefits of a market are highly dependent on its design, and it is premature to speculate or incorporate in this integration study.

## Simulation Inputs

Table 7 provides key inputs to the solar integration study production cost simulations.

**Table 7**
Inputs for the solar integration study production cost simulations

| Input | Assumed input level |
|---|---|
| Solar production | Water year 2012 |
| Snake River streamflows | Water year 2012 (median-type streamflows) |
| Customer demand | Water year 2012 |
| Nymex—Natural gas prices | Water year 2012 |
| Mid-C—Electric power market prices | Water year 2012 |
| Non-wind PURPA[1] | Water year 2012 |
| Wind (PURPA and PPA)[1] | Water year 2013 |
| Geothermal PPAs | Water year 2014 |

[1] PPA and PURPA represent facilities from which generation is contractually purchased as a power purchase agreement (PPA) or under the federal *Public Utility Regulatory Policies Act of 1978* (PURPA).

The selection of water year 2012 for the majority of the inputs was driven by the selection of Snake River streamflows for water year 2012 (October 1, 2011–September 30, 2012) and the objective to use time-synchronous input data to the greatest possible extent. Snake River Basin streamflow conditions as observed in water year 2012 were selected because the observed water year 2012 Brownlee reservoir inflow volume of 13.6 million acre-feet is representative of median-type streamflow conditions. A graph of Brownlee inflow volumes for water years 1990 to 2013 is provided in Appendix 1.

The solar production data used in the production cost simulations are considered to be the solar production that would have been observed during water year 2012 had the four studied solar build-out scenarios existed. As described previously, the solar production data is developed by applying a wavelet smoothing transformation technique to 5-minute interval AgriMet and SolarAnywhere data. Importantly, the use of observed customer demand from water year 2012 allows time synchronization between solar and customer demand data in the study.
While customer demand has grown since 2012, the benefit of using time-synchronous

customer demand and solar production data is considered to justify the use of 2012 customer demand data. Monthly average customer demand used in the modeling is provided in Appendix 1.

Water year 2012 Nymex natural gas prices and Mid-C electric power market prices are inputs to the simulations. These prices, expressed as a monthly average, are provided in Appendix 1.

Wind capacity under contract with Idaho Power grew by more than 60 percent during water year 2012, expanding from 395 MW of installed capacity to 638 MW. Because of the non-constant amount of on-line wind capacity during water year 2012, the simulations used observed hourly wind production data for water year 2013. The amount of on-line wind capacity during water year 2013 changed only by the addition of a single 40 MW project added during December 2013 that brought wind to the current on-line capacity of 678 MW. Monthly energy production used in the modeling is included in Appendix 1.

The remaining energy purchased from non-wind PURPA qualifying facilities is input into the simulations as observed during water year 2012. The monthly energy from the non-wind PURPA facilities in included in Appendix 1.

Baseload generation from geothermal facilities contractually selling to Idaho Power under PPAs is input as currently projected from these facilities. The amount of baseload generation delivered from these facilities varies seasonally. The amount used in the production cost simulations ranges from 22 MW to 32 MW.

## Simulation Model

Idaho Power used an internally developed system operations model for the solar integration 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
- Generator minimum/maximum output levels
- Market purchase/sale constraints
- Generator ramping rates

The model also stipulated that demand and resources were exactly in balance and importantly that hourly reserve requirements were satisfied. The extra capacity in reserve held to manage variability and uncertainty in solar production drives the production cost differences between the study's two cases. The derivation of the extra capacity in reserve held for solar is described previously in this report.

## Wind and Load Reserves

Capacity in reserve to manage variability and uncertainty in load and wind is included in the simulations in equivalent amounts for the study's two cases. By carrying equivalent amounts in reserve for load and wind, the production cost differences yielded by the study's simulations can be attributed to the extra capacity held in reserve for solar. Thus, while reserves carried for load and wind are not drivers of production cost differences in the paired simulations, it is nevertheless desirable in simulating the system as accurately as possible to incorporate reserve levels for load and wind representative of levels carried in practice.

To manage variability and uncertainty in load, capacity in reserve equal to 3 percent of load is held on dispatchable generators in the modeling for the solar integration study. The amount of simulated capacity in reserve for balancing wind is based on an analysis performed for the Idaho Power wind integration study as described in the February 2013 *Wind Integration Study Report* (Idaho Power 2013). The simulated reserves for the solar integration study are based on a scaling of the reserves at the wind study's 800 MW wind build-out scenario to the water year 2013 wind build-out of 678 MW.

## Contingency Reserve Obligation

The study of integration impacts and costs focuses on the need to carry bidirectional capacity in reserve for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity in reserve 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., the loss of a major generating unit or major transmission line). System modeling for the solar integration study imposes 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 study cases (i.e., base and test).

## Flexible Capacity Resources

As described previously, the focus of the production cost simulations for the solar integration study is the real-time market activities occurring as part of hour-ahead system scheduling. The study assumes hour-ahead schedulers require the delivery of forecast hourly average solar production and the lower and upper bounds for solar production 45 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is then assumed binding, and unexpected levels of solar production occurring during the operating hour being scheduled must be managed by Idaho Power's system.

To manage deviations in solar production from the forecast during the operating hour, Idaho Power must schedule incremental and decremental capacity in reserve on dispatchable generators. In the modeling for the study, this capacity in reserve is scheduled on Hells Canyon Complex (HCC) hydroelectric generators (Brownlee, Oxbow, and Hells Canyon), natural gas-fired generators (Langley Gulch, Danskin, and Bennett Mountain), and Jim Bridger coal-fired generators. The allocation of reserve to these generators matches Idaho Power's practice for balancing variations in wind production and load.

# RESULTS

The objective of the Idaho Power solar integration study is to determine the costs of the operational modifications necessary to integrate solar photovoltaic power plant generation. The integration costs are driven by the need to carry extra capacity in reserve to allow bidirectional response from dispatchable generators to unplanned excursions in solar production. The simulations performed for the Idaho Power solar integration study indicate the following costs associated with holding the extra capacity in reserve (Table 8). The provided costs are the costs to integrate solar production for calendar year 2014, and are not costs averaged or levelized over the life of a solar power plant.

**Table 8**
Average integration cost per MWh for solar build-out scenarios

| | 0-100 MW | 0-300 MW | 0-500 MW | 0-700 MW |
|---|---|---|---|---|
| **Integration cost** | \$0.40/MWh | \$1.20/MWh | \$1.80/MWh | \$2.50/MWh |

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest \$0.10.

The integration cost results in Table 8 are the cost per MWh to integrate the full installed solar power plant capacity at the respective scenarios studied. For example, the integration cost results indicate the total solar power plant capacity making up the 500 MW build-out scenario brings about costs of \$1.80 for each megawatt-hour (MWh) integrated.

Integration costs can be expressed alternatively in terms of incremental costs. Integration costs when expressed incrementally assume early projects are assessed lesser integration costs, and later projects need to make up the difference to allow full cost recovery for a given build-out scenario. For example, if solar plants comprising the first 100 MW build-out are assessed integration costs of \$0.40/MWh, then plants comprising the increment between 100 MW and 300 MW need assessed integration costs of \$1.50/MWh to allow full recovery of the \$1.20/MWh costs to integrate 300 MW of solar plant capacity. Incremental solar integration costs are provided in Table 9.

**Table 9**
Incremental integration cost results for solar build-out scenarios

| | 0–100 MW | 100–300 MW | 300–500 MW | 500–700 MW |
|---|---|---|---|---|
| **Incremental integration cost** | \$0.40/MWh | \$1.50/MWh | \$2.80/MWh | \$4.40/MWh |

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest \$0.10.

# Study Findings

## *Hour-Ahead Solar Production Forecasting*

Analyses suggest a persistence-based forecast with adjustment to account for known changes in the sun's position provides a reasonable production forecast for hour-ahead operations scheduling. The persistence-based hour-ahead solar production forecast used for the study is based entirely on observed production and consequently could be readily adopted in practice.

While a day-ahead solar production forecast would be necessary in practice for a balancing authority integrating solar, deviations from the day-ahead forecast can be managed through a combination of market transactions and operations modifications, and consequently the study imposes no reserve requirement to cover deviations for day-ahead solar production forecasts.

Compared to wind, system operators managing a balancing authority integrating solar would have the benefit of at least six hours at the start of day with no or little solar production. During this period of no or little solar production, system operators could evaluate the day-ahead solar production forecast using information from updated weather forecast products and begin to plan for necessary actions to manage deviations from the day-ahead solar production forecast.

In contrast, deviations from the hour-ahead solar production forecast can only be covered by Idaho Power's dispatchable generators. The analysis for the solar integration study by design determines the amounts of bidirectional capacity in reserve that system operators would need to schedule to position dispatchable generators to cover possible deviations from the hour-ahead solar production forecast. Integration costs are a result of the sub-optimal scheduling of the dispatchable generators associated with holding the solar-caused capacity in reserve.

## *Comparison to Wind Integration*

This study indicates solar plant integration costs are lower than wind plant integration costs. The lower integration costs associated with solar are fundamentally the result of less variability and uncertainty. As described in the preceding section, the study assumes deviations in solar plant production from day-ahead forecast levels can be managed through a combination of market transactions and operations modifications, allowing day-ahead generation scheduling to avoid extra reserve burden. Therefore, reserves carried for solar generation can be focused on readying dispatchable generators to respond to unplanned solar excursions from hour-ahead production forecasts. Moreover, logic incorporated in the derivation of lower and upper bounds on the hour-ahead production forecast, which can be readily adopted in practice, allows the adjustment of the bounds in response to observed solar production patterns. In effect, the hour-ahead forecast is based on a persistence of level of production (adjusted for the known change in the sun's position), as well as a persistence of variability in production. The consequence of these methods is that bidirectional capacity held in reserve on dispatchable generators to respond to solar variability and uncertainty is less than that required for responding to wind.

Qualitatively, solar is more predictable than wind. Sunrise and sunset times, as well as the time of solar noon, are a certainty. The theoretical maximum level of production can be readily derived, reflecting patterns on daily, monthly, and seasonal time scales. Finally, land requirements for a solar power plant are likely to promote a relatively high level of dispersion, which is critical to the mitigation of impacts from severe and abrupt ramps in production exhibited by individual panels in response to passing clouds. The effects of geographic dispersion are discussed further in the following section.

## Geographic Dispersion

Production for a single solar photovoltaic panel exhibits severe and abrupt intermittency during variably cloudy conditions; a TRC member expressed during a meeting that for a single panel, the drop in production from a cloud is effectively instantaneous. The effect of severe and abrupt intermittency is commonly attributed to the absence of inertia in the photovoltaic process. While the intermittency effect is severe for a single panel, dampening occurs when considering the production from a solar plant-sized aggregation of panels, and even further dampening occurs when considering the production from several solar plants spread over a region such as southern Idaho. Therefore, geographic dispersion has significant influence on solar integration impacts and is perhaps of greater importance for solar than wind.

The four studied solar build-out scenarios each have capacity installed at six southern Idaho locations spread over more than 220 miles from east to west. Because of the substantial geographic dispersion, severe instantaneous ramps in solar production for the study data are relatively infrequent. If solar plant development in southern Idaho occurs in a more clustered fashion than assumed for this study, actual integration impacts and costs will be higher than the results of this study.

## Transmission and Distribution

The focus of Idaho Power's solar integration study is a macro-level investigation of the operations modifications necessary to maintain balance between power supply and customer demand for a balancing authority integrating photovoltaic solar plant generation. The objective is to understand the impacts and costs of the sub-optimal operation of dispatchable generating capacity. The study is not an investigation of integration issues related to the delivery of energy from proposed solar photovoltaic power plants to the retail customer; these issues are addressed in individual interconnection studies performed on a plant-by-plant basis.

## Spring-Season Integration

The production cost simulations suggest reserve requirements are particularly problematic when hydroelectric resources are highly constrained, such as frequently occurs during spring-season periods characterized by high water, low customer demand, and high generation from variable generating resources, such as wind and solar. Experience has shown wind integration to be particularly challenging during these periods, and the simulations suggest similar challenges integrating solar. This study finding is corroborated by NREL in the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013), which reports the need for flexibility is notably high during the spring and that during these periods the curtailment of variable generation is one source of flexibility enabling the balancing of generation and customer demand.

# CONCLUSIONS

The cost to integrate the variable and uncertain delivery of energy from solar photovoltaic power plants is driven by the need to carry extra capacity in reserve. This extra capacity in reserve is necessary to allow bidirectional response from dispatchable generators to unplanned excursions in solar production. The simulations performed for Idaho Power's solar integration study indicate the costs associated with holding the extra capacity in reserve (Table 8).

## Further Study

The integration of variable generation, including the study of methods for determining integration impacts and costs, continues to be the subject of considerable research. The breadth of this research highlights the interest in variable-generation integration, as well as the evolution of study methods. Idaho Power appreciates the level of interest in its study of integration of variable generation and recognizes the likelihood of a second-phase study with expanded scope.

During the course of the solar integration study, in discussions with the TRC and participants of the public workshop, Idaho Power has received suggestions for a second-phase study of solar integration. Suggestions for a second phase include the study of the following:

- Alternative water-year types (e.g., low-type and high-type)
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Smaller solar build-out scenarios (e.g., 50 MW of installed capacity)
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Distributed solar systems (i.e., rooftop systems)
- Correlation between solar, wind, and load variability and uncertainty
- Improved forecasting methods
- Energy imbalance markets
- Voltage/frequency regulation

Idaho Power will consider these suggestions during the development of scope for a second-phase study.

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[UVIG and NREL]. Utility Variable-Generation Integration Group and National Renewable Energy Laboratory. No date. Principles for Technical Review Committee (TRC) involvement in studies of variable generation integration into electric power systems. http://variablegen.org/wp-content/uploads/2009/05/TRCPrinciplesJune2012.pdf. Accessed June 2014.

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**Appendix 1**
Solar integration study appendix

# Table of Contents

# INTRODUCTION

This appendix contains supporting data and explanatory materials used to develop Idaho Power's *2014 Solar Integration Study*.

The main document, the *2014 Solar Integration Study*, contains a full narrative of Idaho Power's process for studying solar integration costs. For information or questions concerning the study, contact Idaho Power:

Idaho Power—Resource Planning
1221 W. Idaho St.
Boise, Idaho 83702
208-388-2623

# TECHNICAL REVIEW COMMITTEE

The Technical Review Committee (TRC) was formed during summer 2013 to provide input, review, and guidance for the study. It is comprised of participants from outside of Idaho Power that have an interest and/or expertise with the integration of intermittent resources onto utility systems.

As part of preparing the *2014 Solar Integration Study*, Idaho Power held one public meeting and four TRC meetings. Idaho Power values these opportunities to convene, and the TRC members have made significant contributions to this plan.

## List of TRC Members

Brian Johnson...................University of Idaho

Jimmy Lindsay.................Portland General Electric (formerly of Renewable Northwest Project)

Kurt Myers........................Idaho National Laboratory

Paul Woods......................(formerly of City of Boise)

Cameron Yourkowski......Renewable Northwest Project (replacing Jimmy Lindsay)

### *Regulatory Commission Staff Observers*

Brittany Andrus................Public Utility Commission of Oregon (OPUC) staff

John Crider.......................OPUC Staff

Rick Sterling ....................Idaho Public Utilities Commission (IPUC) staff

## TRC Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2013 | Thursday, August 15 | Introductions and role of TRC<br>Idaho Power system overview<br>Formulation of basic study design<br>Establish solar futures<br>Techniques for building solar generation data<br>Closing thoughts and comments |
| 2013 | Thursday, September 19 | Study design<br>Key study components<br>Hydro—WY 2011 vs. WY 2012 vs. WY 2013<br>Solar—WY 2011 vs. WY 2012 vs. WY 2013<br>Market power prices<br>Natural gas prices<br>Solar penetration levels |
| 2014 | Monday, January 6 | Review of Study Design<br>Solar Data Availability<br>Wavelet-based Variability Model<br>Analysis Conclusions |
| 2014 | Friday, May 16 | Review of Integration Study Design<br>Review of IPUC Filing<br>Development of Reserve Requirement for solar scenarios |
| 2014 | Thursday, May 29 | Review of Operating Reserves<br>Review of Production Cost Model |

## Public Workshop Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2014 | Thursday, May 1 | Introduction of Technical Review Committee<br>Idaho Power system overview<br>Study objective<br>Study design<br>System modeling<br>Next steps |

# DATA INPUTS AND ASSUMPTIONS

## Natural Gas Price Assumptions

**Table 1**
Actual monthly average Nymex price for water year 2012

| Year | Month | Average Monthly Price |
|---|---|---|
| 2011 | October | $3.76 |
| | November | $3.52 |
| | December | $3.36 |
| 2012 | January | $3.08 |
| | February | $2.68 |
| | March | $2.45 |
| | April | $2.19 |
| | May | $2.04 |
| | June | $2.43 |
| | July | $2.77 |
| | August | $3.01 |
| | September | $2.63 |

## Market Power Price Assumptions

**Table 2**
Actual average Mid-Columbia dollars/megawatt-hour (MWh) for water year 2012

| Year | Month | Average Monthly Price |
|---|---|---|
| 2011 | October | $26.02 |
| | November | $30.81 |
| | December | $30.13 |
| 2012 | January | $24.53 |
| | February | $23.50 |
| | March | $16.30 |
| | April | $8.99 |
| | May | $5.81 |
| | June | $4.50 |
| | July | $12.05 |
| | August | $24.75 |
| | September | $24.47 |

# IPC Customer Load Data

**Table 3**
Actual average megawatt (MW) for water year 2012

| Year | Month | Average Load |
|---|---|---|
| 2011 | October | 1,403 |
| | November | 1,563 |
| | December | 1,729 |
| 2012 | January | 1,680 |
| | February | 1,597 |
| | March | 1,457 |
| | April | 1,504 |
| | May | 1,742 |
| | June | 2,108 |
| | July | 2,388 |
| | August | 2,197 |
| | September | 1,679 |

# Idaho Power Existing Generation

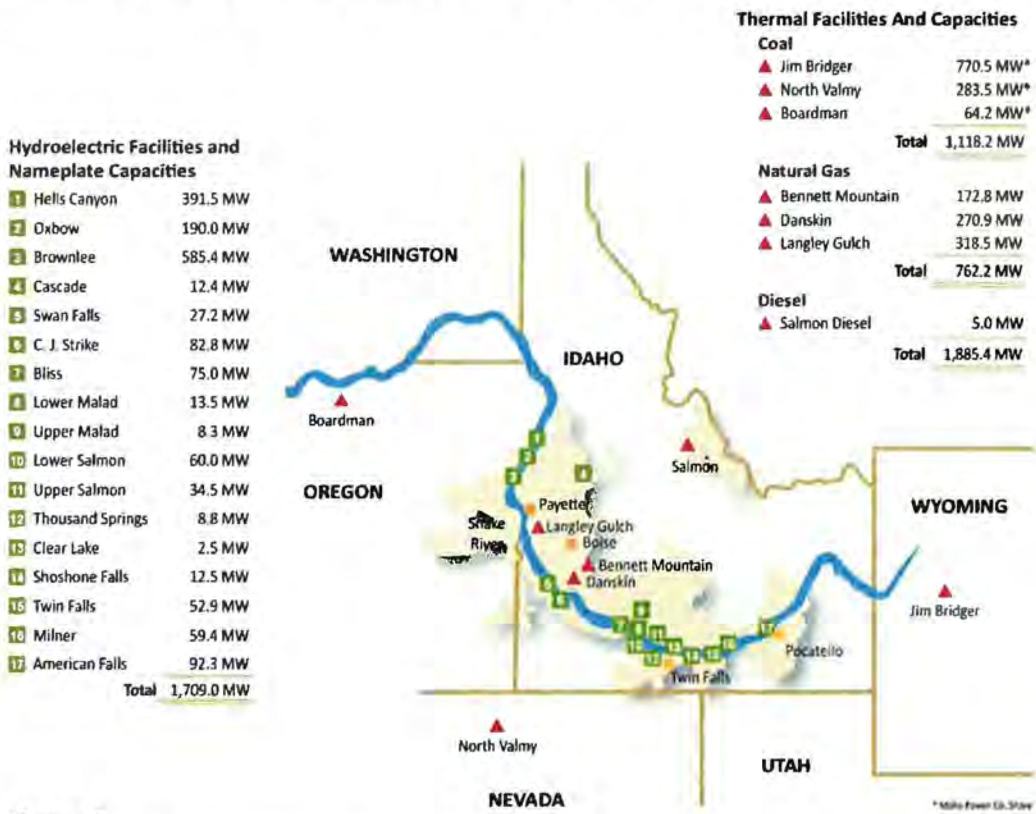



**Figure 1**
Existing Idaho Power generating resources

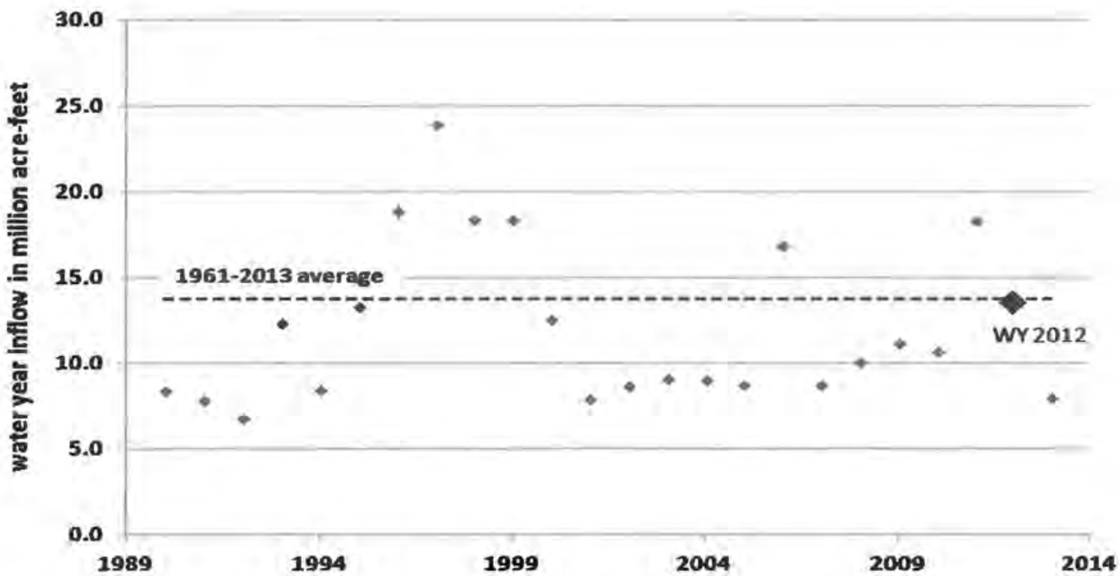



**Figure 2**
Brownlee Reservoir inflow by water year

# Hydroelectric Generation Data

## *Run-of-River Projects*

**Table 4**
Actual monthly average MW (aMW) for water year 2012

| Year | Month | aMW |
|---|---|---|
| 2011 | October | 447 |
| | November | 418 |
| | December | 415 |
| 2012 | January | 358 |
| | February | 365 |
| | March | 380 |
| | April | 388 |
| | May | 252 |
| | June | 337 |
| | July | 292 |
| | August | 251 |
| | September | 208 |

# Wind Generation Data

## *Aggregate PPA and PURPA Projects*

**Table 5**
Actual monthly aMW for water year 2013

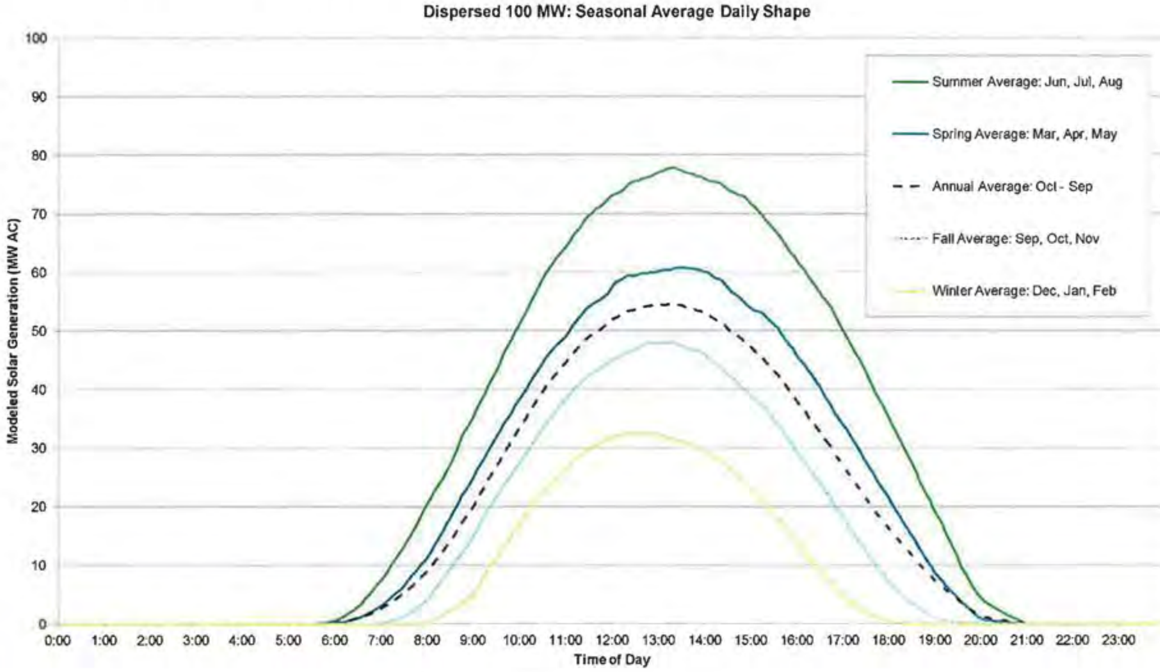
| Year | Month | aMW |
|---|---|---|
| 2011 | October | 95 |
| | November | 190 |
| | December | 120 |
| 2012 | January | 194 |
| | February | 167 |
| | March | 191 |
| | April | 172 |
| | May | 166 |
| | June | 163 |
| | July | 144 |
| | August | 131 |
| | September | 116 |

# Non-Wind PURPA Generation Data

**Table 6**
Actual monthly aMW for water year 2012

| Year | Month | aMW |
|---|---|---|
| 2011 | October | 96 |
| | November | 52 |
| | December | 45 |
| 2012 | January | 43 |
| | February | 43 |
| | March | 54 |
| | April | 104 |
| | May | 135 |
| | June | 131 |
| | July | 140 |
| | August | 130 |
| | September | 111 |

# Solar Production Data



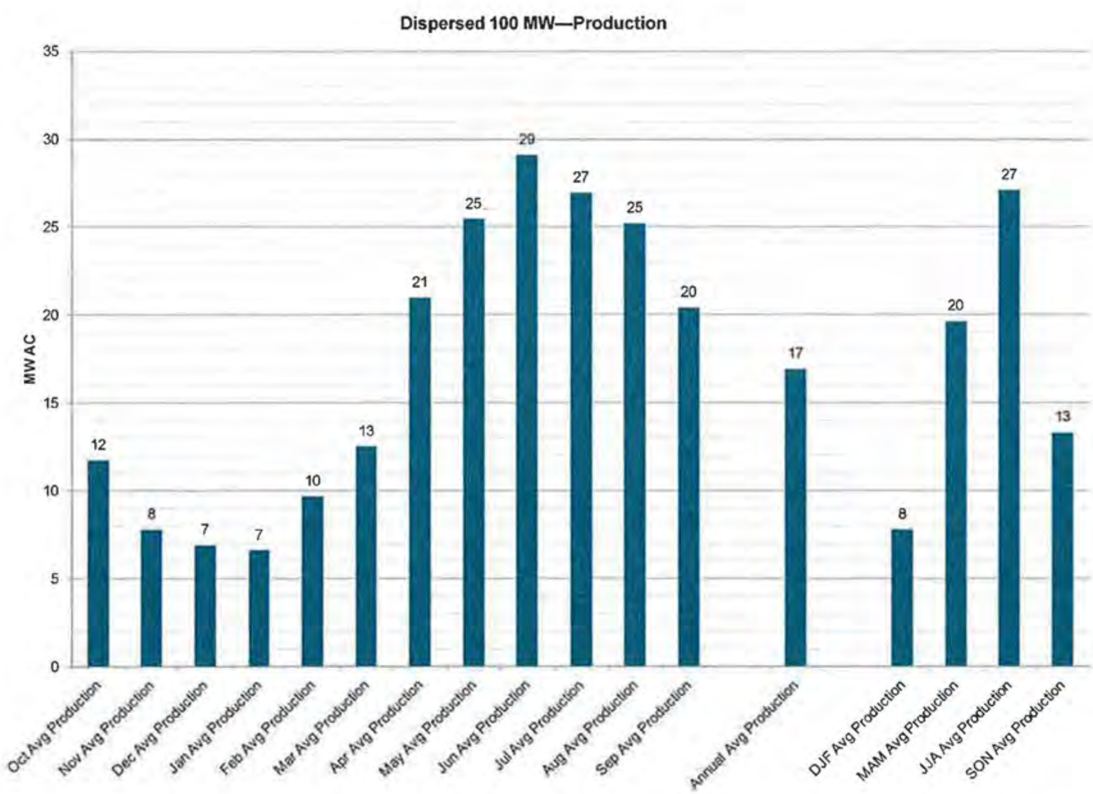
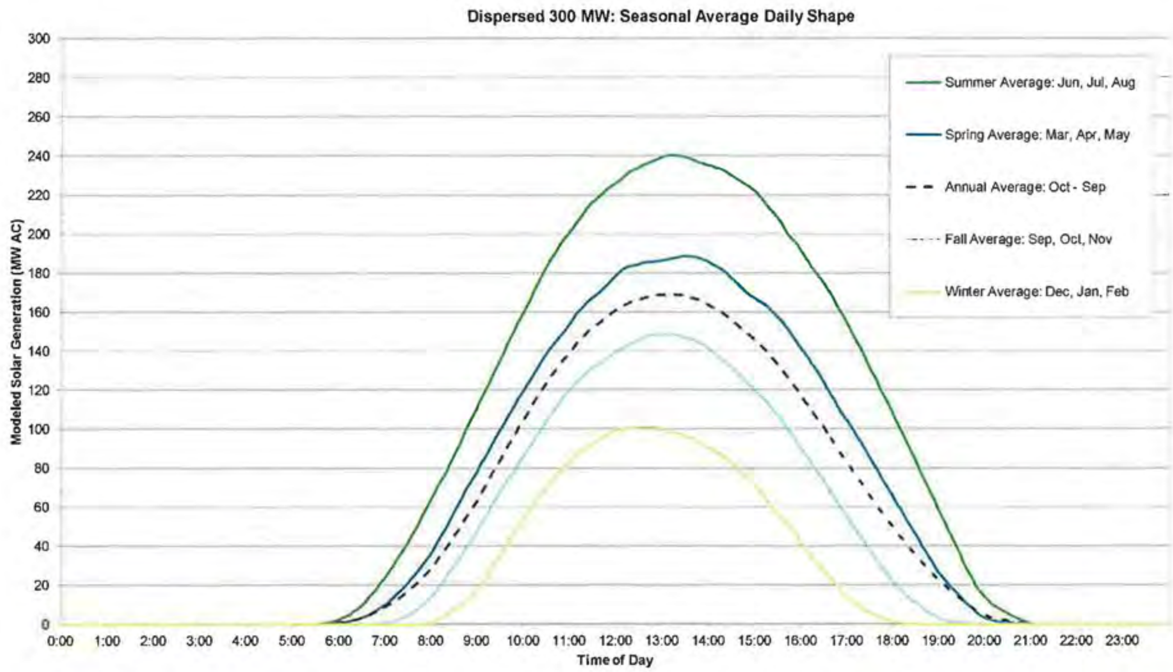




**Figure 3**
Dispersed 100 MW



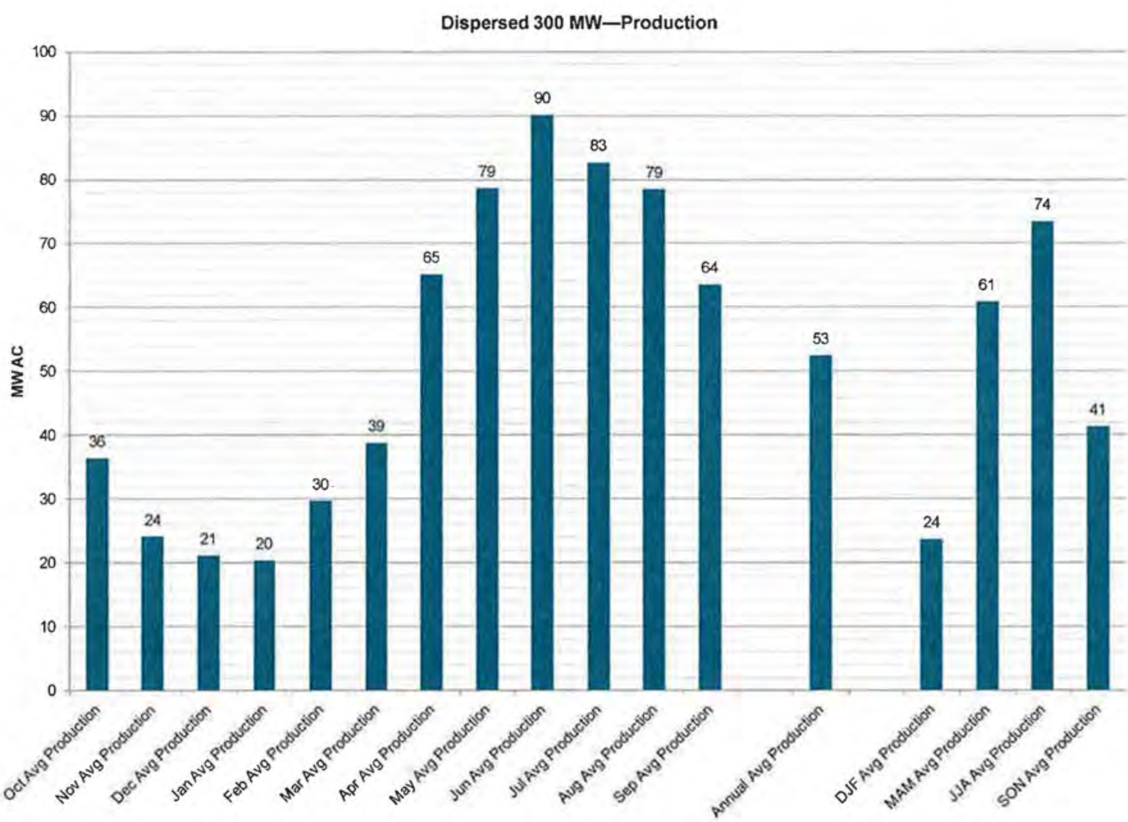




**Figure 4**
Dispersed 300 MW

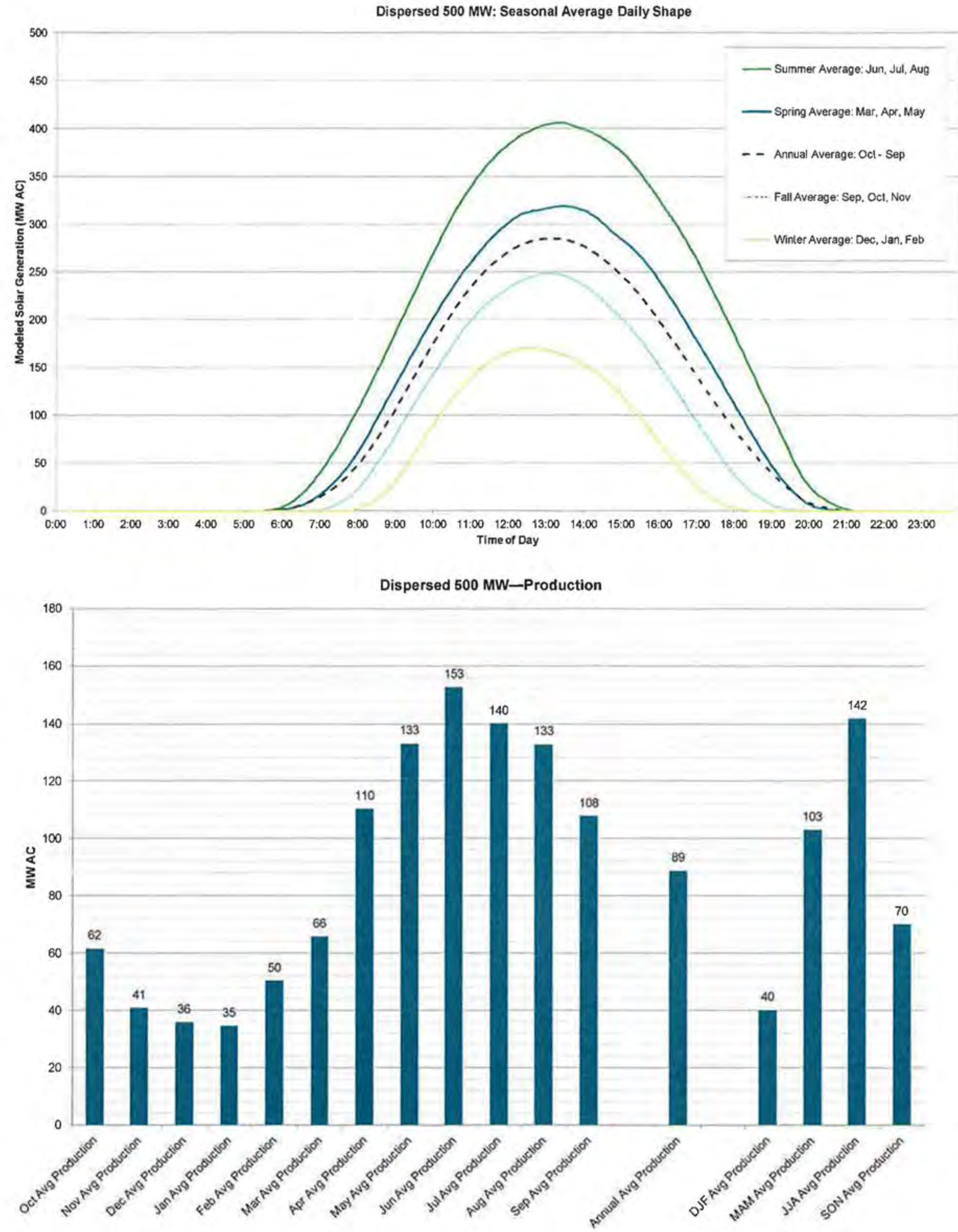



**Figure 5**
Dispersed 500 MW

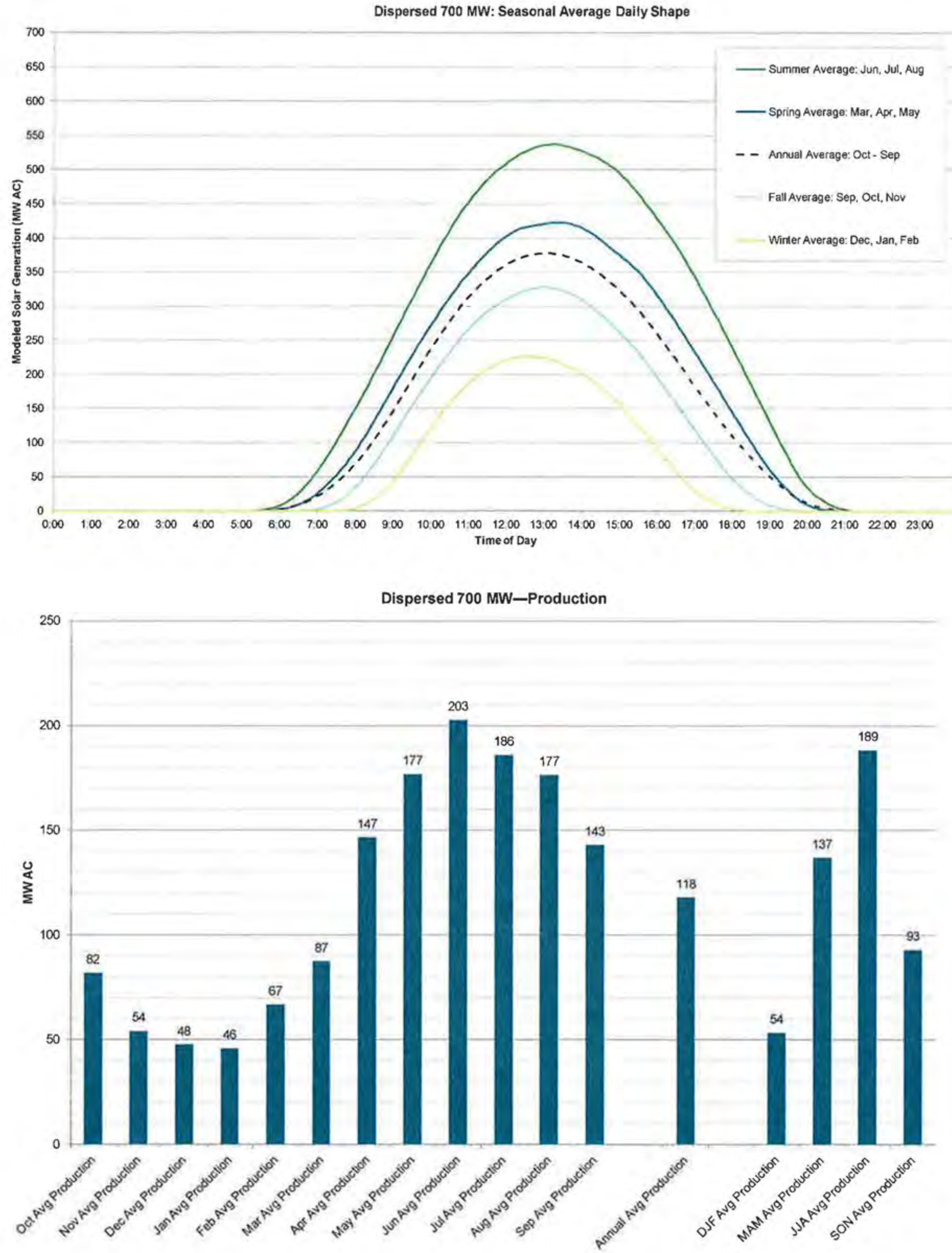



**Figure 6**
Dispersed 700 MW

# Derivation of Hour-Ahead Solar Production Forecast and Upper/Lower Bounds

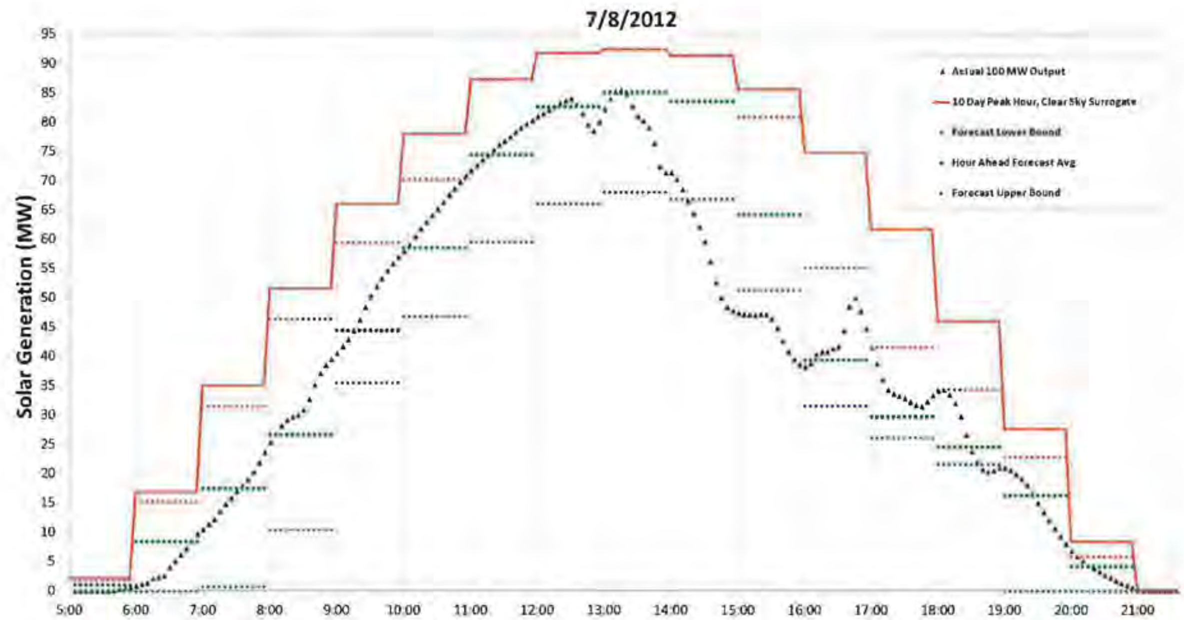



**Figure 8**
Hour-ahead forecast example

The average forecast is shown on Figure 8 as the green series. For each hour of the day, the forecast average is calculated by applying the follow equation:

$$Forecast\ Avg_{(t)} = Forecast\ Obs(MW)_{(t_{-1}:00 \rightarrow t_{-1}:15)} * \frac{Avg\ CSIS_{(t:00 \rightarrow t:55)}}{Avg\ CSIS_{(t_{-2}:20 \rightarrow t_{-1}:15)}}$$

Where:

$t$ = forecast hour

*CSIS* = Clear Sky Index Surrogate

The Clear Sky Index Surrogate (CSIS) is an important measure of the maximum amount of solar generation the system could experience in any given hour. The CSIS is a component of the average solar production forecast and accounts for the seasonal changes that influence solar photovoltaic generation. This value is unique for every hour of the year. The CSIS is calculated using 5-minute, modeled production data from the wavelet-based variability model (WVM). The CSIS is calculated by taking the maximum 5-minute observation for a given hour. This maximum value is the absolute maximum for a given hour over a 10-day period. After identifying the absolute maximum from water year 2011, the forecast also identifies the absolute maxima for water years 2012 and 2013. With the three absolute maxima identified from the three water years analyzed, the forecast applies the maximum CSIS observed in three years of data for a given hour. It is noted that the ratio of the CSIS values, described in the above equation, result in the least amount of average production forecast error. Multiple variations of this ratio were tested, and the final version of the ratio was the most accurate. The process detailing the calculation of the CSIS is described in the equations below.

$$\boldsymbol{CSIS}_{(t)} = Max\left(\left[CSIS_{(Water\ Year\ 2011)}\right], \left[CSIS_{(Water\ Year\ 2012)}\right], \left[CSIS_{(Water\ Year\ 2013)}\right]\right)$$

Where:

$$\boldsymbol{CSIS}_{(Water\ Year\ 2011)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \ldots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

$$\boldsymbol{CSIS}_{(Water\ Year\ 2012)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \ldots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

$$\boldsymbol{CSIS}_{(Water\ Year\ 2013)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \ldots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

Where:

$t$= forecast hour

$d$= forecast day

Figure 8 is a good example of how the persistence-based forecast does very well under the majority of solar conditions and how a forecasting model struggles with extreme weather events. Despite the limitations of a persistence forecast, within a short period of time the forecast returned to accurate predictions. Figure 8 is a select, extremely variable generation profile. The afternoon observations that fall beneath the lower bound forecast are included in the 2.5 percent of lower forecast error reported in the solar integration study. Generally, the forecast does well capturing the variability in production due to solar. The forecast has the ability to tighten the range between the upper and lower bounds. This ensures the amount of capacity held in reserve is sufficient but not unduly large.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UM ______**

| | |
|---|---|
| In the Matter of | ) |
| IDAHO POWER COMPANY | ) |
| Application for Approval of Solar Integration Charge. | ) |

**IDAHO POWER COMPANY**

**DIRECT TESTIMONY**

**OF**

**MICHAEL J. YOUNGBLOOD**

**April 24, 2015**

**Q. Please state your name and business address.**

A. My name is Michael J. Youngblood 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 Manager of Regulatory Projects in the Regulatory Affairs Department.

**Q. Please describe your educational background.**

A. In May of 1977, I received a Bachelor of Science Degree in Mathematics and Computer Science from the University of Idaho. From 1994 through 1996, I was a graduate student in the Executive MBA program of Colorado State University. Over the years, I have attended numerous industry conferences and training sessions, including Edison Electric Institute's "Electric Rates Advanced Course."

**Q. Please describe your work experience with Idaho Power.**

A. I began my employment with Idaho Power in 1977. During my career, I have worked in several departments of the Company and subsidiaries of IDACORP, including Systems Development, Demand Planning, Strategic Planning, and IDACORP Solutions. From 1981 to 1988, I worked as a Rate Analyst in the Rates and Planning Department where I was responsible for the preparation of electric rate design studies and bill frequency analyses. I was also responsible for the validation and analysis of the load research data used for cost-of-service allocations.

From 1988 through 1991, I worked in Demand Planning and was responsible for the load research and load forecasting functions of the Company, including sample design, implementation, data retrieval, analysis, and reporting. I was responsible for the preparation of the five-year and twenty-year load forecasts used in revenue projections and resource plans, as well as the presentation of these forecasts to the public and regulatory commissions.

From 1991 through 1998, I worked in Strategic Planning. As a Strategic Planning Associate, I coordinated the complex efforts of acquiring Prairie Power Cooperative, the first acquisition of its kind for the Company in 40 years. From 1996 to 1998, as a part of a Strategic Planning initiative, I helped develop and provide two-way communication between customers and energy providers using advanced computer technologies and telecommunications.

From 1998 to 2000, I was a General Manager of IDACORP Solutions, a subsidiary of IDACORP, reporting to the Vice President of Marketing. I was directly responsible for the direction and management of the Commercial and Industrial Business Solutions division.

In 2001, I returned to the Regulatory Affairs Department and worked on special projects related to deregulation, the Company's Integrated Resource Plan ("IRP"), and filings with both the Idaho Public Utilities Commission ("IPUC") and the Public Utility Commission of Oregon ("OPUC" or "Commission").

In 2008, I was promoted to the position of Manager of Rate Design for Idaho Power. In that position I was responsible for the management of the rate design strategies of the Company, as well as the oversight of all tariff administration.

In January of 2012, I became the Manager of Regulatory Projects for Idaho Power, which is my current position. In this position, I provide the regulatory support for many of the large individual projects and issues currently facing the Company. Most recently that has included providing regulatory support for the inclusion of the Langley Gulch power plant investment in rate base and supporting the Company's efforts to address numerous issues involving Qualifying Facilities ("QF") as defined under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including the Company's efforts in Case No. GNR-E-11-03, the review of PURPA QF contract provisions. Most recently, and pertinent to this docket, I provided direct testimony for the Company in its Idaho Application to Implement Solar Integration Rates and Charges, IPUC Docket IPC-E-14-18.

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

A. Idaho Power is requesting that the OPUC authorize the Company to implement solar integration rates and charges consistent with its 2014 solar integration study ("Study" or "2014 Study" or "Solar Study"). The 2014 Solar Study Report is attached as Idaho Power/101, DeVol/1-36. Mr. DeVol's testimony provides a summary of the Solar Study, a description of the Technical Review Committee and process utilized for the Study, and the results of the Study. The purpose of my testimony is to provide the Commission with the Company's request to implement solar integration rates and charges based upon the costs identified by the 2014 Solar Study.

**Q. Have solar integration rates and charges based upon the costs identified by the 2014 Solar Study been implemented in the Company's Idaho jurisdiction?**

A. Yes they have. On February 11, 2015, the Idaho Public Utilities Commission ("IPUC") issued Order No. 33227 in Case No. IPC-E-14-18, approving a Settlement Stipulation between Idaho Power, the IPUC Commission Staff, the Idaho Conservation League, Sierra Club and Snake River Alliance, implementing the solar integration rates and charges as filed by the Company.

**Q. Based on the results of the 2014 Study, what is the cost of integrating solar generation on Idaho Power's electrical system?**

A. As presented in Mr. DeVol's testimony, the Solar Study analyzed four solar build-out scenarios at installed capacities of: 100 megawatts ("MW"), 300 MW, 500 MW, and 700 MW. The results of the Solar Study show the integration costs indicated in the following tables:

**Average Integration Cost per MWh**
**(2014 cost and dollars)**

| Build-out Scenarios | 0-100 MW | 0-300 MW | 0-500 MW | 0-700 MW |
|---|---|---|---|---|
| Integration Cost | $0.40 | $1.20 | $1.80 | $2.50 |

**Incremental Integration Cost per MWh**
**(2014 cost and dollars)**

| Penetration Level | 0-100 MW | 100-300 MW | 300-500 MW | 500-700 MW |
|---|---|---|---|---|
| Integration Cost | $0.40 | $1.50 | $2.80 | $4.40 |

The costs identified by the Solar Study reflect the costs to integrate solar generation for the calendar year 2014. The costs are reported in 2014 dollars and were rounded to the nearest ten (10) cents. They are not averaged or levelized over the life of the solar project or plant.

**Q. What is the difference between the Average Integration Cost and the Incremental Integration Cost described in the 2014 Study?**

A. The Average Integration Cost, as shown above, reports an average cost per megawatt-hour ("MWh") for each of the four discrete solar build-out scenarios modeled in the Study. In other words, the Average Integration Cost reflects the average cost per MWh to integrate one block of solar generation, independently, for each penetration level of solar generation: 0-100 MW; 0-300 MW; 0-500 MW; and 0-700 MW. Conversely, the Incremental Integration Cost indicates the cost of integrating solar generation as it would be assigned across the four blocks of solar generation penetration levels, in 200 MW increments.

**Q. Please provide an example to further explain the distinction between Average Integration Cost and Incremental Integration Cost.**

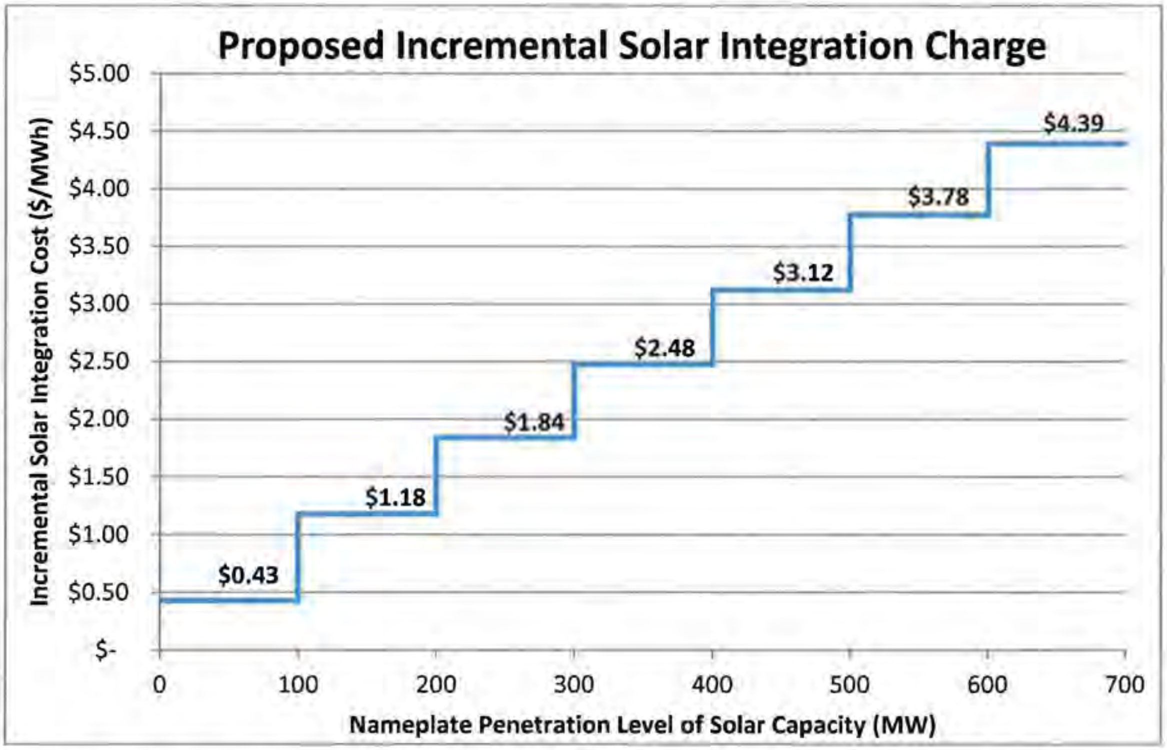
A. Certainly. According to the 2014 Study, the Average Integration Cost for all solar generation from 0-700 MW is $2.50 per MWh. That means that if the total cost of integrating 700 MW of solar were to be spread equally to all 700 MW of solar generation, the cost of integration would be $2.50 for each MWh generated. However, if that same cost of integrating 700 MW of solar were to be broken up into 100 and 200 MW increments, the Incremental Integration Cost for the first 100 MW of solar generation would be only $0.40 per MWh. The incremental cost of integration for the next 200 MW of solar generation (from 100 MW to 300 MW), assuming that the first 100 MW of solar generation remains at $0.40 per MWh, would be $1.50 per MWh. For the next 200 MW (300 MW to 500 MW), again assuming that the cost per MWh for the each of the first two blocks of integration remained unchanged, would be a cost of $2.80 per MWh. The last 200 MW (500 MW to 700 MW) of solar generation would incur a cost of $4.40 per MWh.

In aggregate, the total cost of integrating solar identified by either method, the Average Integration Cost or the Incremental Integration Cost, is the same. Essentially, the cost of solar integration increases as the penetration levels of solar increase on the system. The Study identified the cost to integrate solar generation at four discrete penetration levels. However, if costs are assigned on an incremental basis, then costs are more closely assigned with the cause of those costs, and thus the initial generation is assigned a lower cost than the later generation that shows up when it is more costly to integrate.

**Q. How does the Company propose to implement solar integration cost recovery?**

A. Idaho Power proposes that a solar integration charge be established to collect the incremental cost of integration at each 100 MW of solar generation penetration. When Idaho Power first applied for a solar integration charge in Idaho (IPUC Case No. IPC-E-14-18), there were no solar projects paying any integration charges on Idaho Power's system, and therefore, the solar integration charge simply started at zero and increased consistent with the costs of integration identified in the Solar

Study, at every 100 MW of solar nameplate capacity penetration level. The proposed solar integration charges are rounded to the nearest penny and are illustrated in the chart below:




**Q. How does the Company propose to implement solar integration charges in the Company's Oregon jurisdiction?**

A. Similar to the implementation in the Company's Idaho jurisdiction, Idaho Power recommends that the Commission allocate costs on a per MWh basis for incremental levels of solar penetration. Idaho Power also proposes that solar integration charges be set forth in a schedule, specifically established for intermittent generation integration charges.

**Q. Have you provided an example of what an integration schedule might look like?**

A. Yes. Idaho Power/201, Youngblood/1-16 is a draft Schedule 86, Solar Generation Integration Charges. The integration charges from Schedule 86 would be deducted from the avoided cost rates established for and set out in a PURPA contract.

**Q. Can you describe the proposed Schedule 86, Solar Generation Integration Charges, you provide in Idaho Power/201, Youngblood/1-16?**

A. Yes. Schedule 86 is a draft of a new schedule which is intended to provide the incremental integration charges to be assessed to solar QFs whose generation resource is variable and intermittent in nature. Schedule 86 would provide the solar integration charges consistent with the most recent integration study applicable to solar generation. The draft of Schedule 86 submitted as Idaho Power/201, Youngblood/1-16 contains the proposed incremental integration charges for solar generation based upon the 2014 Study, and which are consistent with the solar integration charges implemented by the IPUC in the Company's Idaho jurisdiction. The charges set forth in Schedule 86 are the amounts to be deducted from avoided cost rates each year, beginning in the year the project comes online, based on the nameplate capacity of installed solar generation at the scheduled operation date of the proposed project. Adoption of a schedule would allow integration costs to be updated for new contracts as additional solar generation is added to the system, or whenever a new solar integration study is completed and identifies a change in integration costs. Having the costs set forth in Schedule 86 provides transparency for the developers as to what the appropriate integration charges would be based upon the scheduled operation date of the proposed project.

**Q. Can you describe the format in which the integration charges are set out in Schedule 86?**

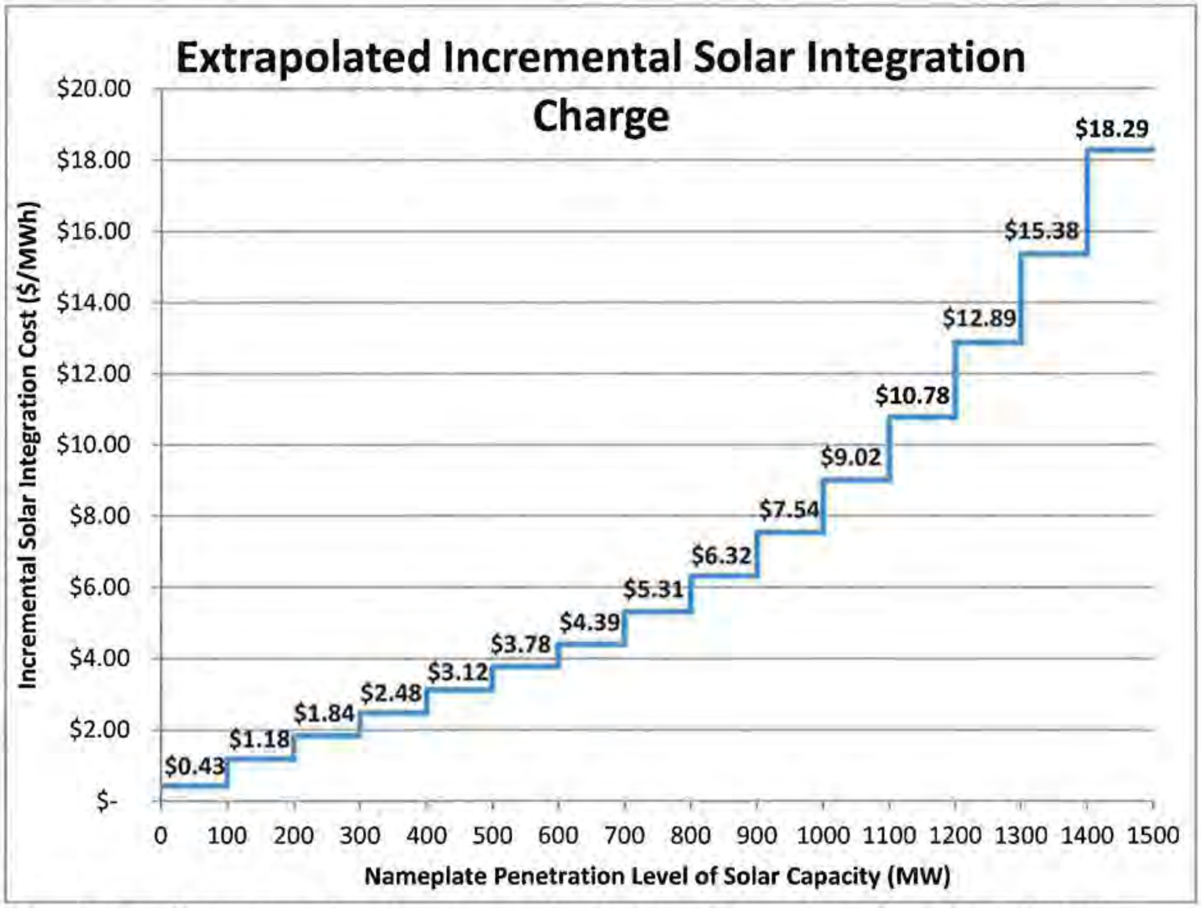
A. Yes. For simplicity and clarity, Idaho Power has formatted the integration charges to appear in the same format as the Idaho Tariff Schedule 87. Each penetration level (each 100 MW increment) has its own table clearly identified and set forth in Schedule 86, and discloses both the levelized integration charge, as well as the non-levelized stream of integration charge amounts listed by year. The scheduled operation date for the proposed generation project is used as the starting point in the table, and each yearly amount through the term of the proposed contract is set out accordingly.

**Q. Is the Company proposing any solar integration charges in addition to those currently implemented in Schedule 87 in Idaho?**

A. Yes. As I stated earlier, when Idaho Power first applied for a solar integration charge in Idaho, there were no solar projects paying any integration charges on Idaho Power's system, and therefore, the solar integration charge simply started at zero and increased by 100 MW increments to 700 MW. The last table for solar integration charges in Schedule 87 is for the 601 – 700 MW of solar capacity penetration level. Since the time of the Company's filing in the Idaho case, the Company has received solar project requests for pricing that have exceeded the 700 MW identified in the table. Therefore, the Company is proposing to augment the Oregon Schedule 86 to include incremental solar integration charges through 1,500 MW of solar capacity.

**Q. How does the Company propose to augment the incremental solar integration charges?**

A. In IPUC Order No. 33227, the Idaho Commission stated that in the event that solar penetration exceeded the Study's 700 MW level, the Company was directed to "utilize the same process/methodology that it applied in its first study to extrapolate integration charges as solar penetration increases." Therefore, based upon that directive, in order to determine the additional incremental pricing, I simply developed a mathematical formula to fit the curve of the existing increments which were based upon the 2014 Solar Study, and then used that formula to extrapolate the incremental charges from 700 MW to 1,500 MW in 100 MW increments. The chart below shows the results of that extrapolation:




**Q. Is the Company planning on conducting another solar integration study?**

A. Yes, the Company is currently in the process of developing a new solar integration study. As part of the Settlement Stipulation in IPUC Docket No. IPC-E-14-18, the parties agreed that Idaho Power would initiate a second solar integration study in January 2015, which we did. The 2015 solar integration study will utilize a Technical Review Committee ("TRC") which includes members with expertise in solar generation, variable energy integration and electrical grid operations. In addition, the TRC includes participation from both the Idaho and Oregon Commission Staff.

**Q. Does the proposed Oregon Schedule 86 include the extrapolated integration costs defined above?**

A. Yes. The Company's proposed Oregon Schedule 86 includes the same 100 MW incremental levels from 0 to 700 MW as approved in Idaho, and then includes the additional 100 MW increments from 701 MW through 1,500 MW, as defined above.

**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 Michael J. Youngblood

Schedule 86

April 24, 2015

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES

APPLICABILITY

This schedule is applicable to all qualifying facility ("QF") generators interconnected to the Company that have solar generation of an intermittent nature. The initial charges within this schedule are to be assessed to solar generation based upon the total nameplate capacity of solar generation interconnected to Company's system.

SOLAR INTEGRATION CHARGES

The following tables are applicable to all QF solar generation contracts that come online after May 1, 2015:

*Continued on next page*

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**0 - 100 MW Solar Capacity Penetration Level**

| **LEVELIZED** | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 0.54 |
| 2015 | 0.56 |
| 2016 | 0.58 |
| 2017 | 0.59 |
| 2018 | 0.61 |
| 2019 | 0.63 |

| **NON-LEVELIZED** | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 0.43 |
| 2015 | 0.44 |
| 2016 | 0.46 |
| 2017 | 0.47 |
| 2018 | 0.48 |
| 2019 | 0.50 |
| 2020 | 0.51 |
| 2021 | 0.53 |
| 2022 | 0.54 |
| 2023 | 0.56 |
| 2024 | 0.58 |
| 2025 | 0.60 |
| 2026 | 0.61 |
| 2027 | 0.63 |
| 2028 | 0.65 |
| 2029 | 0.67 |
| 2030 | 0.69 |
| 2031 | 0.71 |
| 2032 | 0.73 |
| 2033 | 0.75 |
| 2034 | 0.78 |
| 2035 | 0.80 |
| 2036 | 0.82 |
| 2037 | 0.85 |
| 2038 | 0.87 |
| 2039 | 0.90 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**101 - 200 MW Solar Capacity Penetration Level**

| **LEVELIZED** | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 1.49 |
| 2015 | 1.53 |
| 2016 | 1.58 |
| 2017 | 1.63 |
| 2018 | 1.68 |
| 2019 | 1.73 |

| **NON-LEVELIZED** | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 1.18 |
| 2015 | 1.22 |
| 2016 | 1.25 |
| 2017 | 1.29 |
| 2018 | 1.33 |
| 2019 | 1.37 |
| 2020 | 1.41 |
| 2021 | 1.45 |
| 2022 | 1.50 |
| 2023 | 1.54 |
| 2024 | 1.59 |
| 2025 | 1.63 |
| 2026 | 1.68 |
| 2027 | 1.73 |
| 2028 | 1.79 |
| 2029 | 1.84 |
| 2030 | 1.89 |
| 2031 | 1.95 |
| 2032 | 2.01 |
| 2033 | 2.07 |
| 2034 | 2.13 |
| 2035 | 2.20 |
| 2036 | 2.26 |
| 2037 | 2.33 |
| 2038 | 2.40 |
| 2039 | 2.47 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**201 - 300 MW Solar Capacity Penetration Level**

| **LEVELIZED** | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 2.32 |
| 2015 | 2.39 |
| 2016 | 2.46 |
| 2017 | 2.54 |
| 2018 | 2.61 |
| 2019 | 2.69 |

| **NON-LEVELIZED** | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 1.84 |
| 2015 | 1.89 |
| 2016 | 1.95 |
| 2017 | 2.01 |
| 2018 | 2.07 |
| 2019 | 2.13 |
| 2020 | 2.20 |
| 2021 | 2.26 |
| 2022 | 2.33 |
| 2023 | 2.40 |
| 2024 | 2.47 |
| 2025 | 2.55 |
| 2026 | 2.62 |
| 2027 | 2.70 |
| 2028 | 2.78 |
| 2029 | 2.87 |
| 2030 | 2.95 |
| 2031 | 3.04 |
| 2032 | 3.13 |
| 2033 | 3.23 |
| 2034 | 3.32 |
| 2035 | 3.42 |
| 2036 | 3.52 |
| 2037 | 3.63 |
| 2038 | 3.74 |
| 2039 | 3.85 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**301 - 400 MW Solar Capacity Penetration Level**

**LEVELIZED**

| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
|---|---|
| 2014 | 3.12 |
| 2015 | 3.22 |
| 2016 | 3.32 |
| 2017 | 3.41 |
| 2018 | 3.52 |
| 2019 | 3.62 |

**NON-LEVELIZED**

| CONTRACT YEAR | NON-LEVELIZED RATES |
|---|---|
| 2014 | 2.48 |
| 2015 | 2.55 |
| 2016 | 2.63 |
| 2017 | 2.71 |
| 2018 | 2.79 |
| 2019 | 2.87 |
| 2020 | 2.96 |
| 2021 | 3.05 |
| 2022 | 3.14 |
| 2023 | 3.23 |
| 2024 | 3.33 |
| 2025 | 3.43 |
| 2026 | 3.53 |
| 2027 | 3.64 |
| 2028 | 3.75 |
| 2029 | 3.86 |
| 2030 | 3.97 |
| 2031 | 4.09 |
| 2032 | 4.22 |
| 2033 | 4.34 |
| 2034 | 4.47 |
| 2035 | 4.61 |
| 2036 | 4.75 |
| 2037 | 4.89 |
| 2038 | 5.03 |
| 2039 | 5.19 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**401 - 500 MW Solar Capacity Penetration Level**

**LEVELIZED**

| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
|---|---|
| 2014 | 3.94 |
| 2015 | 4.06 |
| 2016 | 4.18 |
| 2017 | 4.31 |
| 2018 | 4.44 |
| 2019 | 4.57 |

**NON-LEVELIZED**

| CONTRACT YEAR | NON-LEVELIZED RATES |
|---|---|
| 2014 | 3.12 |
| 2015 | 3.22 |
| 2016 | 3.31 |
| 2017 | 3.41 |
| 2018 | 3.52 |
| 2019 | 3.62 |
| 2020 | 3.73 |
| 2021 | 3.84 |
| 2022 | 3.96 |
| 2023 | 4.08 |
| 2024 | 4.20 |
| 2025 | 4.32 |
| 2026 | 4.45 |
| 2027 | 4.59 |
| 2028 | 4.72 |
| 2029 | 4.87 |
| 2030 | 5.01 |
| 2031 | 5.16 |
| 2032 | 5.32 |
| 2033 | 5.48 |
| 2034 | 5.64 |
| 2035 | 5.81 |
| 2036 | 5.98 |
| 2037 | 6.16 |
| 2038 | 6.35 |
| 2039 | 6.54 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**501 - 600 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 4.76 |
| 2015 | 4.91 |
| 2016 | 5.05 |
| 2017 | 5.21 |
| 2018 | 5.36 |
| 2019 | 5.52 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 3.78 |
| 2015 | 3.89 |
| 2016 | 4.01 |
| 2017 | 4.13 |
| 2018 | 4.25 |
| 2019 | 4.38 |
| 2020 | 4.51 |
| 2021 | 4.64 |
| 2022 | 4.78 |
| 2023 | 4.93 |
| 2024 | 5.07 |
| 2025 | 5.23 |
| 2026 | 5.38 |
| 2027 | 5.55 |
| 2028 | 5.71 |
| 2029 | 5.88 |
| 2030 | 6.06 |
| 2031 | 6.24 |
| 2032 | 6.43 |
| 2033 | 6.62 |
| 2034 | 6.82 |
| 2035 | 7.02 |
| 2036 | 7.24 |
| 2037 | 7.45 |
| 2038 | 7.68 |
| 2039 | 7.91 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**601 - 700 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 5.54 |
| 2015 | 5.71 |
| 2016 | 5.88 |
| 2017 | 6.06 |
| 2018 | 6.24 |
| 2019 | 6.43 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 4.39 |
| 2015 | 4.53 |
| 2016 | 4.66 |
| 2017 | 4.80 |
| 2018 | 4.95 |
| 2019 | 5.09 |
| 2020 | 5.25 |
| 2021 | 5.40 |
| 2022 | 5.57 |
| 2023 | 5.73 |
| 2024 | 5.91 |
| 2025 | 6.08 |
| 2026 | 6.26 |
| 2027 | 6.45 |
| 2028 | 6.65 |
| 2029 | 6.85 |
| 2030 | 7.05 |
| 2031 | 7.26 |
| 2032 | 7.48 |
| 2033 | 7.70 |
| 2034 | 7.94 |
| 2035 | 8.17 |
| 2036 | 8.42 |
| 2037 | 8.67 |
| 2038 | 8.93 |
| 2039 | 9.20 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**701 - 800 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 6.70 |
| 2015 | 6.91 |
| 2016 | 7.11 |
| 2017 | 7.33 |
| 2018 | 7.55 |
| 2019 | 7.77 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 5.31 |
| 2015 | 5.47 |
| 2016 | 5.64 |
| 2017 | 5.81 |
| 2018 | 5.98 |
| 2019 | 6.16 |
| 2020 | 6.35 |
| 2021 | 6.54 |
| 2022 | 6.73 |
| 2023 | 6.93 |
| 2024 | 7.14 |
| 2025 | 7.36 |
| 2026 | 7.58 |
| 2027 | 7.80 |
| 2028 | 8.04 |
| 2029 | 8.28 |
| 2030 | 8.53 |
| 2031 | 8.78 |
| 2032 | 9.05 |
| 2033 | 9.32 |
| 2034 | 9.60 |
| 2035 | 9.89 |
| 2036 | 10.18 |
| 2037 | 10.49 |
| 2038 | 10.80 |
| 2039 | 11.13 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**801 - 900 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 7.98 |
| 2015 | 8.21 |
| 2016 | 8.46 |
| 2017 | 8.71 |
| 2018 | 8.98 |
| 2019 | 9.25 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 6.32 |
| 2015 | 6.51 |
| 2016 | 6.71 |
| 2017 | 6.91 |
| 2018 | 7.11 |
| 2019 | 7.33 |
| 2020 | 7.55 |
| 2021 | 7.77 |
| 2022 | 8.01 |
| 2023 | 8.25 |
| 2024 | 8.50 |
| 2025 | 8.75 |
| 2026 | 9.01 |
| 2027 | 9.28 |
| 2028 | 9.56 |
| 2029 | 9.85 |
| 2030 | 10.14 |
| 2031 | 10.45 |
| 2032 | 10.76 |
| 2033 | 11.08 |
| 2034 | 11.42 |
| 2035 | 11.76 |
| 2036 | 12.11 |
| 2037 | 12.48 |
| 2038 | 12.85 |
| 2039 | 13.24 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**901 - 1000 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 9.52 |
| 2015 | 9.80 |
| 2016 | 10.10 |
| 2017 | 10.40 |
| 2018 | 10.71 |
| 2019 | 11.03 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 7.54 |
| 2015 | 7.77 |
| 2016 | 8.00 |
| 2017 | 8.24 |
| 2018 | 8.49 |
| 2019 | 8.74 |
| 2020 | 9.01 |
| 2021 | 9.28 |
| 2022 | 9.55 |
| 2023 | 9.84 |
| 2024 | 10.14 |
| 2025 | 10.44 |
| 2026 | 10.75 |
| 2027 | 11.08 |
| 2028 | 11.41 |
| 2029 | 11.75 |
| 2030 | 12.10 |
| 2031 | 12.47 |
| 2032 | 12.84 |
| 2033 | 13.23 |
| 2034 | 13.62 |
| 2035 | 14.03 |
| 2036 | 14.45 |
| 2037 | 14.89 |
| 2038 | 15.33 |
| 2039 | 15.79 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**1001 - 1100 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 11.38 |
| 2015 | 11.72 |
| 2016 | 12.07 |
| 2017 | 12.43 |
| 2018 | 12.80 |
| 2019 | 13.19 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 9.02 |
| 2015 | 9.29 |
| 2016 | 9.56 |
| 2017 | 9.85 |
| 2018 | 10.15 |
| 2019 | 10.45 |
| 2020 | 10.77 |
| 2021 | 11.09 |
| 2022 | 11.42 |
| 2023 | 11.76 |
| 2024 | 12.12 |
| 2025 | 12.48 |
| 2026 | 12.85 |
| 2027 | 13.24 |
| 2028 | 13.64 |
| 2029 | 14.05 |
| 2030 | 14.47 |
| 2031 | 14.90 |
| 2032 | 15.35 |
| 2033 | 15.81 |
| 2034 | 16.28 |
| 2035 | 16.77 |
| 2036 | 17.28 |
| 2037 | 17.79 |
| 2038 | 18.33 |
| 2039 | 18.88 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**1101 - 1200 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 13.61 |
| 2015 | 14.01 |
| 2016 | 14.43 |
| 2017 | 14.87 |
| 2018 | 15.31 |
| 2019 | 15.77 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 10.78 |
| 2015 | 11.11 |
| 2016 | 11.44 |
| 2017 | 11.78 |
| 2018 | 12.14 |
| 2019 | 12.50 |
| 2020 | 12.88 |
| 2021 | 13.26 |
| 2022 | 13.66 |
| 2023 | 14.07 |
| 2024 | 14.49 |
| 2025 | 14.93 |
| 2026 | 15.37 |
| 2027 | 15.84 |
| 2028 | 16.31 |
| 2029 | 16.80 |
| 2030 | 17.30 |
| 2031 | 17.82 |
| 2032 | 18.36 |
| 2033 | 18.91 |
| 2034 | 19.48 |
| 2035 | 20.06 |
| 2036 | 20.66 |
| 2037 | 21.28 |
| 2038 | 21.92 |
| 2039 | 22.58 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**1201 - 1300 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 16.26 |
| 2015 | 16.75 |
| 2016 | 17.25 |
| 2017 | 17.77 |
| 2018 | 18.30 |
| 2019 | 18.85 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 12.89 |
| 2015 | 13.28 |
| 2016 | 13.67 |
| 2017 | 14.08 |
| 2018 | 14.51 |
| 2019 | 14.94 |
| 2020 | 15.39 |
| 2021 | 15.85 |
| 2022 | 16.33 |
| 2023 | 16.82 |
| 2024 | 17.32 |
| 2025 | 17.84 |
| 2026 | 18.38 |
| 2027 | 18.93 |
| 2028 | 19.50 |
| 2029 | 20.08 |
| 2030 | 20.68 |
| 2031 | 21.30 |
| 2032 | 21.94 |
| 2033 | 22.60 |
| 2034 | 23.28 |
| 2035 | 23.98 |
| 2036 | 24.70 |
| 2037 | 25.44 |
| 2038 | 26.20 |
| 2039 | 26.99 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**1301 - 1400 MW Solar Capacity Penetration Level**

| **LEVELIZED** | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 19.40 |
| 2015 | 19.98 |
| 2016 | 20.58 |
| 2017 | 21.20 |
| 2018 | 21.84 |
| 2019 | 22.49 |

| **NON-LEVELIZED** | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 15.38 |
| 2015 | 15.84 |
| 2016 | 16.31 |
| 2017 | 16.80 |
| 2018 | 17.31 |
| 2019 | 17.83 |
| 2020 | 18.36 |
| 2021 | 18.91 |
| 2022 | 19.48 |
| 2023 | 20.06 |
| 2024 | 20.66 |
| 2025 | 21.28 |
| 2026 | 21.92 |
| 2027 | 22.58 |
| 2028 | 23.26 |
| 2029 | 23.96 |
| 2030 | 24.67 |
| 2031 | 25.41 |
| 2032 | 26.18 |
| 2033 | 26.96 |
| 2034 | 27.77 |
| 2035 | 28.60 |
| 2036 | 29.46 |
| 2037 | 30.35 |
| 2038 | 31.26 |
| 2039 | 32.19 |

SCHEDULE 86
SOLAR GENERATION INTEGRATION CHARGES
(Continued)

SOLAR INTEGRATION CHARGES (Continued)

**1401 - 1500 MW Solar Capacity Penetration Level**

| LEVELIZED | |
|---|---|
| ON-LINE YEAR | 20 YEAR CONTRACT TERM LEVELIZED RATES |
| 2014 | 23.07 |
| 2015 | 23.77 |
| 2016 | 24.48 |
| 2017 | 25.21 |
| 2018 | 25.97 |
| 2019 | 26.75 |

| NON-LEVELIZED | |
|---|---|
| CONTRACT YEAR | NON-LEVELIZED RATES |
| 2014 | 18.29 |
| 2015 | 18.84 |
| 2016 | 19.40 |
| 2017 | 19.98 |
| 2018 | 20.58 |
| 2019 | 21.20 |
| 2020 | 21.84 |
| 2021 | 22.49 |
| 2022 | 23.17 |
| 2023 | 23.86 |
| 2024 | 24.58 |
| 2025 | 25.31 |
| 2026 | 26.07 |
| 2027 | 26.86 |
| 2028 | 27.66 |
| 2029 | 28.49 |
| 2030 | 29.35 |
| 2031 | 30.23 |
| 2032 | 31.13 |
| 2033 | 32.07 |
| 2034 | 33.03 |
| 2035 | 34.02 |
| 2036 | 35.04 |
| 2037 | 36.09 |
| 2038 | 37.18 |
| 2039 | 38.29 |