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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO UPDATE ITS WIND INTEGRATION RATES AND CHARGES.	)	CASE NO. IPC-E-13-22

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

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.

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 forty 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 VP of Marketing. I was directly responsible for the direction

and management of the Commercial & 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" or "Commission") and the Oregon Public Utility Commission ("OPUC").

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 ("PURPA"), including the Company's efforts in Case No. GNR-E-11-03, the review of PURPA QF contract provisions.

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

A. Idaho Power is requesting that the IPUC authorize the Company to update its wind integration rates and charges consistent with its 2013 Wind Integration Study Report ("2013 Study"). Mr. Philip DeVol's testimony provides the description and results of the 2013 Study. The purpose of my testimony is to provide the Commission with the Company's request and to provide options for regulatory treatment to assess the wind integration charges quantified by Mr. DeVol.

I. HISTORY OF CURRENT INTEGRATION CHARGE

Q. Please provide a brief history of the prior proceedings that led to the current application of wind integration charges in Idaho.

A. On June 17, 2005, due to the anticipated rapid growth in the supply of wind generation, in Case No. IPC-E-05-22, Idaho Power requested a temporary suspension of its purchase obligations for wind generation. On August 4, 2005, the Commission issued Order No. 29839 finding good cause to conduct further proceedings to determine the appropriate amount of adjustment, if any, to integrate wind generation resources. Idaho Power advised the Commission that it intended to perform a study to quantify the

additional costs it would incur directly related to purchasing significant amounts of wind generation.

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

In Case No. IPC-E-07-03, the Commission issued Order No. 30488 in February 2008 approving a joint settlement stipulation and establishing a tiered integration cost structure that increased as nameplate wind generation increased. The stipulation also established a cap of $6.50/MWh with the understanding that each of the utilities

would update their integration studies in the future as more wind generation was added. Order No. 30488 states:

> Idaho Power's published avoided-cost rates for Wind QFs will be adjusted to recognize an assumed cost of integrating the energy generated by Wind QFs as a part of the Company's generating resource portfolio. The rate adjustment will be applied in three tiers, increasing as the total amount of wind integrated onto Idaho Power's system grows. The integration charge for each Wind QF project will be calculated at the time a Wind QF project achieves its Operation Date as that term is defined in the Firm Energy Sales Agreement (FESA) between the Company and the wind QF. The integration charge will be calculated as a percentage (7%, 8% or 9%) of the current 20-year, levelized, avoided-cost rate, subject to a cap of $6.50/MWh. The integration charge as calculated on the Operation Date will remain fixed throughout the term of the contract and will be applied as a decrement to the applicable published rate according to the table below:

	Amount of Wind Online	**Integration Charge**
Tier 1	0 to 300 MW	7% ($6.50/MWh)
Tier 2	301 MW to 500 MW	8% ($6.50/MWh)
Tier 3	501 MW and above	9% ($6.50/MWh)

Order No. 30488, quoting Settlement Stipulation which was approved by the Idaho Commission.

Q. Could you describe the current allocation of wind integration charges for Idaho Power?

A. Yes. As shown on my Exhibit No. 2, Idaho Power currently has 28 wind projects operating on its system for a total nameplate capacity of 678 MW. All are PURPA QF projects except for Elkhorn Wind at 101 MW. 14 of

the projects, 196.72 MW, pay no wind integration charge. One of these projects is a 3 MW Oregon wind QF. Three of the projects, 155.70 MW, are negotiated agreements over the published rate eligibility cap, and thus contain negotiated rates. These three agreements contain a flat integration charge of $6.50/MWh to coincide with the previously ordered cap. The remaining 10 agreements contain a Tier 2 wind integration charge of 8 percent of the published avoided cost rates contained in each contract, with an ultimate cap of $6.50/MWh.

Q. Do all of the QF wind projects pay the $6.50/MWh cap for their wind integration charge?

A. No. In fact none of the QF wind projects that contain the percentage of avoided cost rate integration charge have hit the cap of $6.50/MWh on an annual basis. On an overall average, all wind on Idaho Power's system pays $3.42/MWh on an annual basis, where the previous wind integration study showed a wind integration cost of $7.92/MWh at 500 MW of penetration. Exhibit No. 2 provides additional details regarding what each QF pays for wind integration.

II. OVERVIEW

Q. Based on the results of the 2013 Study, what is the cost of integrating wind generation on Idaho Power's electrical system?

A. As presented in Mr. DeVol's testimony, the 2013 Study analyzed three different levels of wind penetration: 800 MW, 1,000 MW, and 1,200 MW. The 2013 Study was conducted using certain inputs from the 2011 Integrated Resource Plan ("2011 IRP"). Mr. DeVol also discusses how the Company has updated the results from the 2013 Study using inputs from the 2013 Integrated Resource Plan ("Updated 2013 Study"). The results of the Updated 2013 Study show integration costs of $6.83/MWh, $10.22/MWh, and $14.22/MWh, in 2017 dollars, at the three different levels of wind penetration, respectively, providing that the costs for integrating wind into the Company's system were spread equally to all wind generation.

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

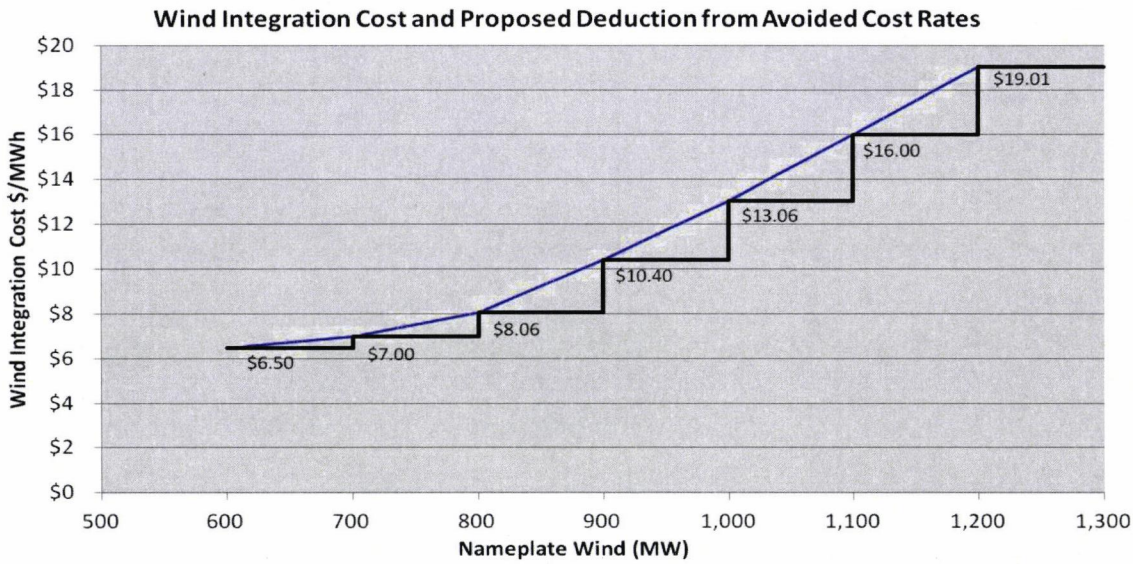
A. Idaho Power currently has 577 MW of PURPA wind and an additional 101 MW from the Elkhorn Valley Wind Farm, for a total of 678 MW of wind generation online.

Q. If the costs of integrating wind generation were not spread evenly across all wind generation, what would be the incremental costs of wind integration for new wind generators at the three different levels of wind penetration?

A. As I have previously discussed, the current wind integration charge authorized by the Commission in

1 Order No. 30488 is assessed based upon a percentage of the
2 avoided cost rates contained in each power purchase
3 agreement. These amounts vary for different PURPA
4 contracts depending on when the projects came online, and
5 the wind integration charge is capped at only $6.50/MWh.
6 Based upon the very conservative assumption that all of the
7 current 678 MW of wind generation were currently being
8 assessed the cap of $6.50/MWh (which they are not) and that
9 they would continue to be assessed just $6.50/MWh in the
10 future, the incremental costs of wind integration at the
11 three different levels for new wind generators would be
12 $8.67/MWh at 800 MW, $24.00/MWh at 1,000 MW, and $34.70/MWh
13 at 1,200 MW. If actual amounts paid by existing wind QFs
14 were used, which is much less than a flat $6.50/MWh, these
15 results would be much higher. The $6.50/MWh assumption was
16 used here to simplify the calculation for presentation
17 purposes.
18 Q. How does the Company propose to account for
19 wind integration costs in avoided cost rates?
20 A. The most straight-forward method would be to
21 account for the current wind integration costs as the
22 Company proposed to do in its Oregon jurisdiction as part
23 of the Oregon Commission's general PURPA docket, Case No.
24 UM 1610. Oregon currently has no wind integration charge,
25 and has not yet issued an order or its decision in Case No.

UM 1610. As presented by Idaho Power witness, Mark Stokes, in the Oregon proceeding, as an initial implementation of a wind integration charge, the current deduction of $6.50/MWh is used until total nameplate wind generation reaches 700 MW. Once 700 MW is reached, the wind integration charge is increased consistent with the costs identified in the 2013 Study at every 100 MW of nameplate capacity penetration. This is illustrated by the following chart from witness Stokes' Oregon testimony:



Idaho Power asked the Oregon Commission to authorize a wind integration charge as shown in the chart above and that a separate tariff schedule be established and maintained for this charge. Direct Testimony of Mark Stokes, pp. 72-73, OPUC Case No. UM 1610. These amounts are based upon the study results using the 2011 IRP inputs, as the 2013 IRP was not yet finalized at the time of filing

this request with the Oregon Commission. Thus, the above chart does not reflect the reduction in wind integration costs that results from updating the 2013 Study with the 2013 IRP inputs.

Unfortunately, application of the wind integration charge is not as straight forward in the state of Idaho, as any change must be incorporated along with the currently existing projects and their various wind integration charges embedded in their power sales agreements. Idaho Power discusses below three separate methods, from which the Commission could choose to implement, to account for wind integration costs in avoided cost rates. I have identified these methods as: Method 1 - Maintain Current Allocation, Method 2 - Current Allocation with Integration Tariff, and Method 3 - Equitable Allocation of Costs.

Q. Could you describe the three methods you mentioned?

A. Yes. However, before doing so I would like to raise a couple of issues that are necessary to keep in mind when considering potential methods for recovering wind integration costs for Idaho Power's system. The costs associated with wind integration are currently vastly under collected. They are assessed on a percentage basis of various avoided cost rates which results in an inequitable contribution of the various wind QFs to the cost of

integrating wind on the system. The use of percentage of avoided cost rates really has no relation to actual costs of the additional reserves necessary to integrate variable and intermittent resources on the system. Additionally, setting the amount of wind integration charge for the entire duration of the power sales agreement assures further under collection of integration costs as those costs rise. This under collection from existing wind QFs results in an additional allocation to new wind QFs - the incremental difference - required to make the Company's customers whole, and remain indifferent to the addition of PURPA QF generation, that substantially increases the wind integration cost for new wind projects.

The Company proposes two overall changes, incorporated into each of the methods discussed below, to address the collection of wind integration costs. Change One - Abandon the use of percentage of avoided cost rate allocation, and instead allocate a fixed amount based upon penetration level, and Change Two - decouple the wind integration charge from the avoided cost rate contained in the power sales agreement, and instead have wind integration costs assessed as a stand-alone tariff charge.

III. METHOD 1 - MAINTAIN CURRENT ALLOCATION

Q. Please describe Method 1 - Maintain Current Allocation, in greater detail.

A. The first method from which the Commission could choose to implement integration charges is by not changing anything except for updating the rates and penetration levels. In Order No. 30488, three tier levels were established with increasing wind integration costs at each level, and all new contracts utilized the applicable charges depending on the amount of wind generation online at the time the wind QF achieves its Operation Date.

Q. Are there concerns with maintaining the status quo for assessing integration charges?

A. Yes. First of all, as mentioned above, the current methodology calculates the wind integration charge using a percentage (7, 8, or 9 percent) of the current 20-year, levelized, avoided-cost rate, and all charges are subject to a cap of $6.50/MWh. Not only is allocation on the basis of a percentage of avoided cost rates unrelated to the actual costs to integrate wind, but another concern is that there is a lack of transparency as to what the wind integration charge is for each wind QF. In fact, depending on when each QF contract came online, they may be paying differing amounts to cover the costs of wind integration. In addition, the charges will change year-to-year and the year in which the cap is reached, if it is reached at all, will vary among the contracts. While the 2013 Study indicates that the incremental cost of wind integration is

1 significantly above the cap, the actuality is that, on an
2 annual basis, most of the current wind generators are not
3 even paying the full cap of $6.50/MWh.
4 Q. What do you mean that on an annual basis, most
5 of the current wind generation contracts are not paying the
6 current cap of $6.50/MWh?
7 A. As previously discussed, Exhibit No. 2 is a
8 list of the Company's current PURPA wind generation online.
9 Shown on the table are the integration charges being
10 assessed by project and the year the $6.50/MWh cap would be
11 achieved. I have calculated the average annual integration
12 cost the Company recovers by project, and other than the
13 three negotiated projects which included the $6.50/MWh in
14 their pricing models, none of them are at the cap on an
15 annual basis. In fact, because so many of the projects are
16 not currently being assessed an integration charge at all,
17 the average annual wind integration charge per megawatt-
18 hour currently being recovered for all projects is just
19 $3.42/MWh. This is way below the cap of $6.50, and
20 significantly below the integration costs identified in
21 both the Company's previous and current wind integration
22 studies.
23 Q. Does the Company recommend a modification to
24 Method 1 if the Commission chooses to maintain the status
25 quo?

A. Yes. Based upon the concerns expressed above, if the Commission chooses to maintain the status quo, the Company recommends abandoning the assessment on a percentage of avoided cost rate basis and establishing a fixed charge at each of the three tiers. If the Commission were to adopt this method, the three tiers and applicable charges from the Updated 2013 Study would be as listed in the table below:

	Amount of Wind Online	Integration Charge
Tier 1	800 MW to 999 MW	$8.67/MWh
Tier 2	1,000 MW to 1,199 MW	$24.00/MWh
Tier 3	1,200 MW and above	$34.70/MWh

IV. METHOD 2 - CURRENT ALLOCATION WITH INTEGRATION TARIFF

Q. What is the second method the Company proposes that the Commission could consider to account for integration costs?

A. The second method the Commission may consider in order to account for integration costs is a slight modification to Method 1. For Method 2, rather than embedding the integration charges as part of the avoided cost prices in the contract rates, as is currently done, the Company would implement a new integration charge tariff which would identify the integration charges at the respective levels, separately from the power sales agreement.

Q. Please describe this method in greater detail.

A. One of the difficulties of the current method is that integration costs are part of the avoided cost rates included in each of the QF contracts. Modifying those charges as integration costs change would be difficult to do. In order to implement the full incremental integration charge outside of the QF contract for new wind QFs, the contracts could refer to an integration tariff, which would establish integration charges that would be deducted from the QFs avoided cost rates contained in the QF contracts.

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

A. Yes. Exhibit No. 3 is an example of a draft tariff, Schedule 87, Variable Generation Integration Charges. The integration charges from Schedule 87 would be deducted from the avoided cost rates established for a PURPA wind contract.

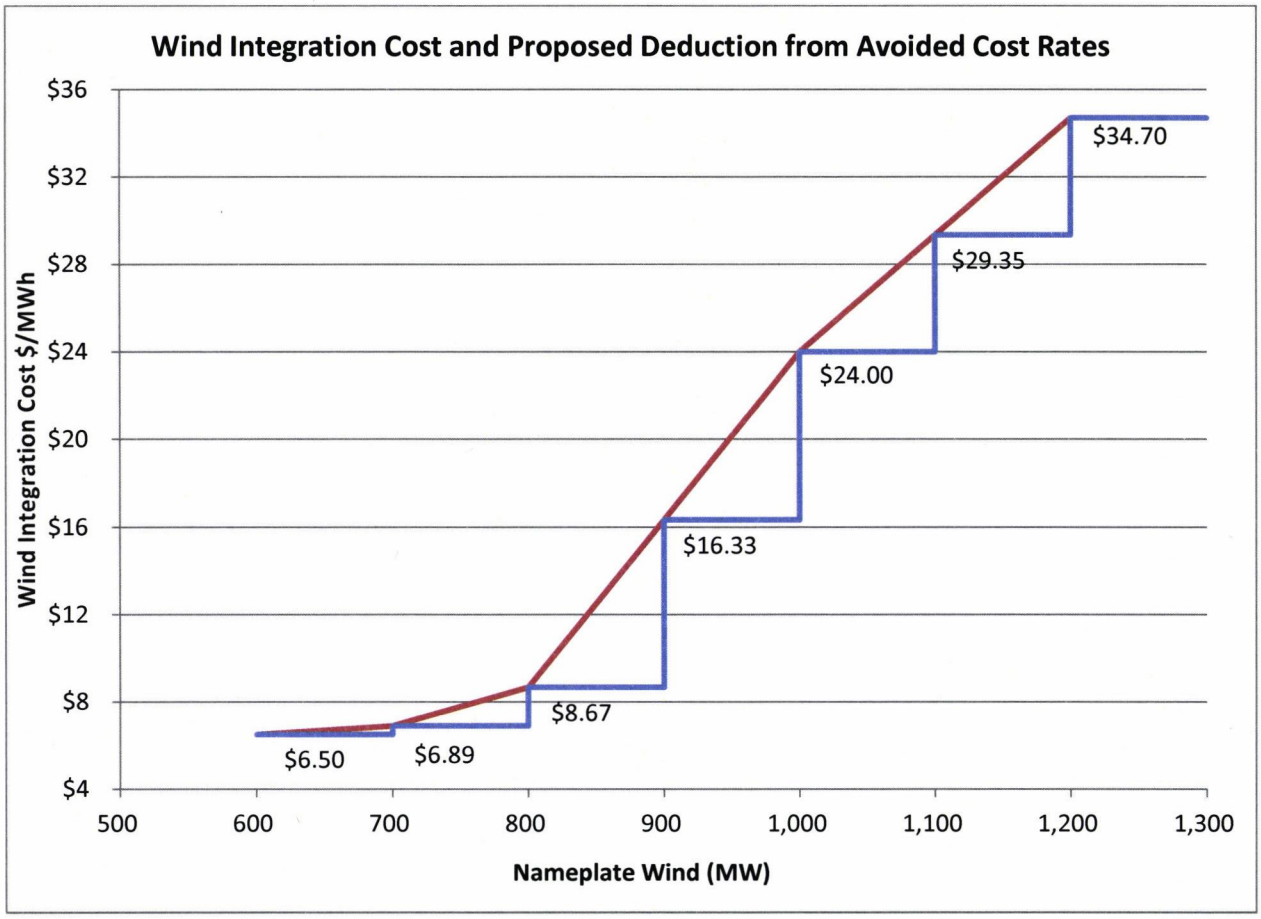
Q. Please describe Exhibit No. 3.

A. Exhibit No. 3 is a draft of a new tariff which is intended to provide the integration charges to be assessed to QFs whose generation resource is variable or intermittent in nature, like wind or solar. Currently Schedule 87 would provide only the wind integration charges based on the Updated 2013 Study. These charges are the amounts to be deducted from avoided cost rates based on the

nameplate capacity of installed wind generation. Being tariff-based would allow wind integration costs to be updated as additional wind generation is added, up to 1,200 MW, or whenever new wind integration studies identified a change in costs.

Q. What are the wind integration charges shown on Exhibit No. 3?

A. Exhibit No. 3 reflects the integration charges that would be deducted from avoided cost rates providing the Commission chose to maintain the status quo and require new wind generation to pay the incremental costs of integration. The figure below represents the methodology the Company would propose to incorporate the Updated 2013 Study results. Under this method, the current wind integration charge of $6.50/MWh would be used until total nameplate wind generation reached 700 MW. Once 700 MW is reached, the wind integration charge would be increased to $6.89/MWh. As shown below, subsequent increases would occur as each incremental 100 MW of wind generation is added.



Q. What are the benefits of providing wind integration charges for avoided cost rates through a tariff?

A. When the full integration costs for intermittent generation are not being fully recovered by existing projects, the incremental integration costs increase significantly, adversely impacting new wind generators. If the integration charges were part of a tariff schedule that could be updated as integration costs changed, or new integration studies were completed, all contracts whose avoided cost rates were adjusted by the

1 integration charges in the schedule would be affected
2 uniformly, spreading the changes in costs over a greater
3 number of participants.

4 **V. METHOD 3 - EQUITABLE ALLOCATION OF COSTS**

5 Q. What is the third method the Company proposes
6 that the Commission consider to account for integration
7 costs?

8 A. The third method the Commission may consider
9 to account for wind integration costs is to spread the
10 integration costs equitably across all PURPA wind
11 generators. In this way, all wind generators would be
12 sharing equitably in the costs of integrating wind onto the
13 Company's system. In addition, this would have the effect
14 of reducing the charge per megawatt-hour, and in effect,
15 not penalize new wind generation from coming online.

16 Q. Would the concept of implementing an
17 integration tariff work if the Commission chose to
18 establish integration charges equitably across all PURPA
19 wind generators?

20 A. Yes, I believe conceptually, a tariff schedule
21 would still be possible for Method 3 if the Commission
22 chose to establish new integration charges equally for all
23 PURPA projects, including those projects which comprise the
24 678 MW of wind generation. However, because of the varying
25 charges that are currently being assessed with current

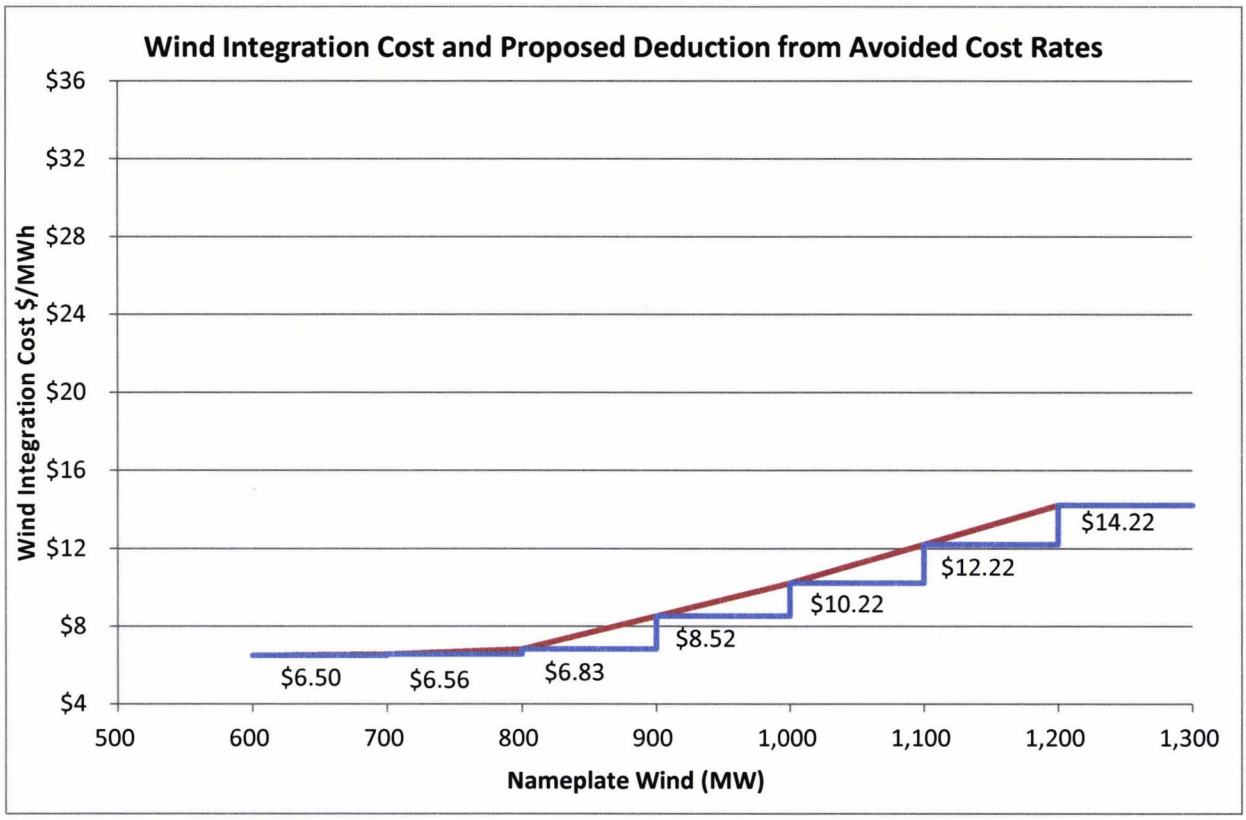
contracts, one may need to make some assumptions for the charges being recovered through existing rates. If the Commission were to assume that all existing contracts were being assessed the cap of $6.50/MWh, then a tariff could include two sets of integration charges.

Q. What would be the two wind integration charges shown on the tariff?

A. A proposed method could include two sets of wind integration charges, one for "Type I" and one for "Type II" contracts. Exhibit No. 4 is a sample of a draft integration tariff that could be used to implement Method 3. The Type I wind integration charge would be for existing contracts, with the assumption that the current cap of $6.50 was being recovered (which it is not). Consequently, the Type I charge currently for all wind integration below 700 MW would be $0.00/MWh, representing no additional charge being assessed. However, the Type II wind integration charge, for those new contracts which would not include an integration charge in their avoided cost rate, would currently be shown as $6.50/MWh for all new wind generation coming online below the 700 MW level. This price would be fixed and deducted from their avoided cost pricing, for all seasons equally throughout the year.

Once wind generation reaches the 700 MW level or above, the Type II charge would increase to $6.56/MWh, in a

similar fashion as it would under the tariff described in Method 2. The Type I charge though, would increase by an incremental difference between the current $6.50/MWh cap and the $6.56/MWh value, or would show a charge of $0.06/MWh. In that way, all existing wind generation, regardless of what their current integration charges are included in their avoided cost rates, would receive a portion of the costs incurred to integrate all wind generation on Idaho Power's system to which they contribute. And, with the assumption that they were at the cap of $6.50/MWh, the incremental charge of $0.06/MWh would mean that effectively, they were paying the same integration charges as the new wind generation projects. As shown below, subsequent increases would occur as each incremental 100 MW of wind generation is added.



Q. Are there any challenges to implementing Method 3?

A. Yes. In order for the Commission to choose to implement these lower integration charges, that would indicate that all contracts would be participating, meaning that the integration costs were being assessed equitably across all wind generation. If it were only assessed on the new wind generation, then the higher levels of integration charges, the incremental cost, would need to be assessed. However, for everyone to participate equitably in paying the costs of wind integration, all generators would need to incur additional integration charges in the future. This method makes the assumption that all wind

generation is currently being assessed $6.50/MWh, which we know is not correct. However, it is difficult to correct the methods that have been implemented previously. It is recognized that all generators would still not be paying the same amount, however, it would be a step in the right direction to provide some equity in sharing the cost of integration. Over time, as contracts expire and new ones are negotiated, the tariff approach would provide a much easier method for updating integration charges and maintaining equity.

Q. Does this conclude your testimony?

A. Yes.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Michael J. Youngblood, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as the Manager of Regulatory Projects in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 29th day of November 2013.

Michael J. Youngblood

Michael J. Youngblood

SUBSCRIBED AND SWORN to before me this 29th day of November 2013.

Christa Bearry

Notary Public for Idaho
Residing at: Boise, Idaho
My commission expires: 02/04/2015

CHRISTA S. BEARRY
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-22

IDAHO POWER COMPANY

YOUNGBLOOD, DI TESTIMONY

EXHIBIT NO. 2

Average Wind Integration Cost Recovered

Note: IPUC order 30488 initiated the Wind Intergration Charge for all future Idaho wind projects.

	Project Identifier	Nameplate Rating	Applicable Commission Jurisdication	Contract Pricing Type	Applicable Published Avoided Cost Schedule	Wind Integration Cost included	Integration Cost Recovered by Project	Average Integration Cost Assessed ($/MWh)	Season 1: 92 Days			Season 2: 123 Days			Season 3: 150 Days		
									Heavy Load	Light Load	Year $6.50 cap is reached	Heavy Load	Light Load	Year $6.50 cap is reached	Heavy Load	Light Load	Year $6.50 cap is reached
1	Project 1	9.00	Idaho	Non Levelized	29391	N/A - Prior to IPUC Order 30488	$0.00										
2	Project 2	10.50	Idaho	Non Levelized	29391	N/A - Prior to IPUC Order 30488	$0.00										
3	Project 3	13.50	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
4	Project 4	10.50	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
5	Project 5	12.00	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
6	Project 6	10.50	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
7	Project 7	21.30	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
8	Project 8	12.00	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
9	Project 9	19.92	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
10	Project 10	22.00	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
11	Project 11	10.50	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
12	Project 12	21.00	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
13	Project 13	21.00	Idaho	Non Levelized	29646	N/A - Prior to IPUC Order 30488	$0.00										
14	Project 14	3.00	Oregon	Non Levelized	OR Schedule 85	N/A - Oregon Contract	$0.00										
15	Project 15	35.70	Idaho	Negotiated		A flat $6.50 per MWh was included in pricing models used during negotiations	$232.05	$6.50									
16	Project 16	80.00	Idaho	Negotiated		A flat $6.50 per MWh was included in pricing models used during negotiations	$520.00	$6.50									
17	Project 17	40.00	Idaho	Negotiated		A flat $6.50 per MWh was included in pricing models used during negotiations	$260.00	$6.50									
18	Project 18	22.50	Idaho	Levelized	30744	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$140.46	$6.24	$5.67	$5.24	Never	$6.50	$6.50	2009	$6.50	$6.50	2009
19	Project 19	21.00	Idaho	Levelized	30744	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$131.09	$6.24	$5.67	$5.24	Never	$6.50	$6.50	2009	$6.50	$6.50	2009
20	Project 20	21.00	Idaho	Levelized	30744	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$131.09	$6.24	$5.67	$5.24	Never	$6.50	$6.50	2009	$6.50	$6.50	2009
21	Project 21	22.00	Idaho	Non Levelized	30744	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$133.87	$6.08	$5.12	$4.70	2026	$6.50	$6.50	2009	$6.50	$6.39	2015
22	Project 22	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
23	Project 23	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
24	Project 24	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
25	Project 25	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
26	Project 26	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
27	Project 27	23.00	Idaho	Non Levelized	31025	8% of the Published Avoided Cost, capped at $6.50 per Mwh	$128.40	$5.58	$4.37	$3.94	2029	$6.50	$6.50	2014	$5.95	$5.37	2020
28	**Total PURPA Wind**	**576.92**					**$2,318.99**										
							$4.02	**Average Cost Recovered / MW**									
29	Elkhorn Valley Wind Farm	100.65															
30	**Total Wind**	**677.57**					**$3.42**	**Average Cost Recovered / MW**									

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-22

IDAHO POWER COMPANY

YOUNGBLOOD, DI TESTIMONY

EXHIBIT NO. 3

SCHEDULE 87
INTERMITTENT GENERATION INTEGRATION CHARGES

APPLICABILITY

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

This schedule is applicable to all QF wind generation contracts that come online after November 1, 2013.

WIND INTEGRATION CHARGES

Total Nameplate Wind Generation	Wind Integration Charge (per megawatt-hour)
Less than 700 MW	$6.50
700 MW - 799 MW	$6.89
800 MW - 899 MW	$8.67
900 MW - 999 MW	$16.33
1,000 MW - 1,099 MW	$24.00
1,100 MW - 1,199 MW	$29.35
1,200 MW or greater	$34.70

SOLAR INTEGRATION CHARGES

Total Nameplate Solar Generation	Solar Integration Charge (per megawatt-hour)
N/A	$0.00

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-22

IDAHO POWER COMPANY

YOUNGBLOOD, DI TESTIMONY

EXHIBIT NO. 4

SCHEDULE 87
INTERMITTENT GENERATION INTEGRATION CHARGES

APPLICABILITY

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

DEFINITIONS

Type I Wind Generation. All QF wind generation contracts coming online prior to December 1, 2013.

Type II Wind Generation. All QF wind generation contracts coming online after December 1, 2013.

WIND INTEGRATION CHARGES

Total Nameplate Wind Generation	Type I Wind Integration Charge (per megawatt-hour)	Type II Wind Integration Charge (per megawatt-hour)
Less than 700 MW	$0.00	$6.50
700 MW - 799 MW	$0.06	$6.56
800 MW - 899 MW	$0.33	$6.83
900 MW - 999 MW	$2.02	$8.52
1,000 MW - 1,099 MW	$3.72	$10.22
1,100 MW - 1,199 MW	$5.72	$12.22
1,200 MW or greater	$7.72	$14.22

SOLAR INTEGRATION CHARGES

Total Nameplate Solar Generation	Solar Integration Charge (per megawatt-hour)
N/A	$0.00

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