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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR DEFERRAL AND RECOVERY OF COSTS ASSOCIATED WITH PARTICIPATION IN AN ENERGY IMBALANCE MARKET.	)	**CASE NO. IPC-E-16-19** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Brandon Karpen, Deputy Attorney General, and in response to the Notice of Modified Procedure and Notice of Comment Deadline issued in Order No. 33627 on October 14, 2016, in Case No. IPC-E-16-19 to submit the following comments.

BACKGROUND

Procedural History

On August 19, 2016, Idaho Power Company filed an Application requesting that the Commission: (1) make a finding that Company participation in the proposed Energy Imbalance Market could net customers long-term benefits; (2) authorize a deferral account to track necessary incremental costs associated with participation; and (3) allow the Company to recover estimated costs from customers in a future rate proceeding. Application at 1.

On September 13, 2016, the Commission issued a Notice of Application and set a deadline of October 4, 2016, for interested parties to petition for intervention. Three parties filed timely petitions and were granted intervention: the Industrial Customers of Idaho Power; the

Snake River Alliance; and the Idaho Conservation League. Staff conferred with the parties, who agreed to the use of Modified Procedure, with a comment deadline of December 15, 2016, and a reply deadline of January 5, 2017.

Energy Imbalance Market

An Energy Imbalance Market (EIM) pools generation of interconnected electricity producers within a region, and dispatches those resources with the goal of accurately matching production with demand. An EIM operates on a nearly real-time basis with multiple participants. More conventional long-term two-party contracts deliver energy in hourly blocks.

In November 2014, the California Independent System Operator (CAISO) and PacifiCorp formed the western EIM. *Id.* at 1-2. The western EIM is a five-minute market administered by CAISO. The market utilizes an automatic model to identify the least-cost energy resources to resolve real-time energy imbalance. *Id.* According to the Company, the western EIM "focuses solely on real-time imbalances and allows EIM entities to retain all balancing responsibilities and transmission provider duties." *Id.* at 2. Participants in the EIM bid resources into the market, and the operator dispatches those resources based on marginal price for energy imbalances factoring in load and available generation. *Id.* The current EIM participants are CAISO, NV Energy, Inc., PacifiCorp, Puget Sound Energy, and Arizona Public Service Company.

With its Application, the Company states that it intends to begin participating in the western EIM in April 2018. The Company claims that the western EIM will benefit customers through "economic efficiency . . ., savings due to diversity of loads and variability of resources within the expanded [EIM] footprint, reduced operational risk . . ., and ability to better support the integration of renewable resources." *Id.* According to the Company, participation in the EIM could result in net power supply expense savings of $4.1 to $5.1 million per year. *Id.* at 4.

STAFF REVIEW

Staff's evaluation of the Company's request to participate in the EIM and defer costs for later recovery is based primarily on Idaho Power's estimate of benefits associated with participation in the EIM. Staff recognizes that the estimate of EIM benefits are assumption driven and there is concern that the benefits may not materialize as forecasted. The conclusions and recommendations in these comments reflect those concerns.

In summary, Idaho Power is proposing to participate in a sub-hourly regional EIM, which will require a unique investment and changes in traditional system operation. Participation costs appear to be best estimates, and will be refined as more information is obtained and will eventually reflect actual cost subject to Commission review. Staff believes that operating efficiencies will improve as the Company gains experience actively participating in the EIM. Staff understands the uncertainty and limitations of estimating benefits derived through modelling but ultimately agrees that the Company's approach to calculating potential benefits is conservative and reasonable under the circumstances.

Staff also considered other factors in reaching its conclusions, including: (1) intangible benefits the Company identified in its Application; (2) similar cases where the Company has requested pre-authorization and ratemaking treatment of future investments; and (3) the size of the investment and the ability to acquire capital for financing.

Based on its analysis, Staff concludes that the overall potential long-term benefits to customers will likely outweigh the incremental cost of joining the EIM. However, given the relatively small amount of benefits, the level of uncertainty, and other factors described above, Staff believes the most reasonable approach is to authorize the Company to establish a deferral account; and to track actual costs incurred rather than estimated costs as proposed by the Company. These prudently incurred costs should not be authorized for recovery until offsetting benefits are also included in rates. Details of Staff's cost-versus-benefit analysis, intangible benefit analysis, cost recovery methods, and recommendations are provided below.

Cost Versus Benefit

Staff thoroughly reviewed the Company's quantification of costs and benefits used to determine the economic viability of joining the EIM. This included a review of the production cost model and methods used to determine the amount of financial benefit that could potentially be realized. Staff also reviewed the upfront and operational costs required for the Company to participate in the EIM including the basis for forming its estimates. Finally, Staff reviewed the Company's net present value (NPV) revenue requirement impact used to show the amount of savings customers may realize when netted against the cost of participation.

Benefit Model Analysis

Idaho Power contracted with Energy and Environmental Economics, Inc. (E3) to conduct a study of the impact of, and potential savings from Idaho Power's participation in the EIM. Due to the complexity of the electricity system, E3 performs simulations in an attempt to realistically model how the system will operate. Staff recognizes that there are inherent challenges in calculating and verifying the benefits that an EIM can generate. To mitigate uncertainty, Staff evaluated several factors including: the overall approach used to conduct the study and to quantify benefits; the appropriateness of the model and modeling methodology relative to the study's objectives; the validity of the model and the assumptions used to reflect system operations with and without an EIM; and the consultant's experience and level of expertise. Staff concluded that the benefit model is reasonable and likely provides a conservative approximation of benefits if the Company participates in the EIM.

In broad terms, E3 derived an annual benefit amount by simulating the bulk power system of the western interconnection for the year 2020 through two separate model runs: an EIM case and a business-as-usual (BAU) case (without Idaho Power's participation in the EIM). E3 derived a relative benefit amount by calculating the difference in the Company's share of net power costs between the two model runs. E3 repeated these runs using four different scenarios in order to test the sensitivity and impact of different variables on the benefit amount: (1) a baseline scenario; (2) a higher renewable buildout scenario; (3) an early coal retirement scenario; and (4) a scenario with a reduced amount of utilities participating in the EIM.[1] Staff requested an additional scenario with higher gas prices ($4.25/MMBTU vs. $3.27/MMBTU in baseline scenario) and therefore higher electricity prices to see its effect on cost savings. The benefit results are summarized in the table below.

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[1] A detailed description of each scenario can be found on page 7 of Exhibit 4 of Kathleen Anderson's direct testimony.

Scenario	Savings to Idaho Power
Baseline Scenario	$4.5 million annually
High Renewable Portfolio Standard Case	$5.1 million annually
Early Coal Retirement	$4.1 million annually
Arizona Public Service Company and Portland General Electric Company not participating in EIM	$4.2 million annually
Higher Gas Price	$5.0 million annually

One of the values of performing sensitivity scenarios is to validate the model. For example, several studies[2] have shown that EIM savings generally increase when the penetration of variable renewable generation or gas prices are higher, which E3's results have shown. However, the results also show that benefits are expected to be lower if there are early coal retirements or less participation in the EIM.

For example, in an early coal retirement scenario, Idaho Power would need to rely more on its gas and hydro resources to meet load which would leave less available capacity to sell into the imbalance market. Similarly, EIM benefits would be lower than expected if there were fewer market participants to purchase Idaho Power's available generation, or for Idaho Power to purchase lower cost generation to meet its own imbalance needs. Thus, the model's results and the relative change in benefit amounts from modeling the scenarios align with what Staff would otherwise expect.

The modeling provides further value by aiding understanding in how the risk of future circumstances could impact potential savings. The model evaluated potential benefits in scenarios involving increased coal plant retirements, increased renewable generation, higher gas prices, or the possibility that other utilities may no longer participate. Given there are relatively small changes in the savings amounts in each of these scenarios compared to the baseline scenario, Staff believes that a future change in circumstances due to these factors will not significantly affect the economic viability of the project.

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[2] *See* EIM Benefit Assessments, available at: https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx

However, modeled benefit results need to be weighed against risks from unanticipated factors. A $4.5 million benefit amount is less than 2% of the Company's $234 million in Idaho allocated actual net power cost according to last year's power cost adjustment (PCA). Staff believes that small, unforeseen change in circumstances could erase such a small benefit amount. Notwithstanding that concern, Staff believes the conservative approach taken by E3 and the Company help mitigate the small power cost savings and much of the uncertainty in determining benefits. Staff believes the following assumptions make the study results conservative:

1. Valuing energy at the estimated cost of production instead of using market-based rates;
2. Modest gas price and renewable penetration rate assumptions;
3. No inclusion of quantified benefits for improved reliability or reduced reserves;
4. No inclusion of benefits that may result in the day-ahead or hour-ahead market from better EIM visibility across the system;
5. No inclusion of maintenance benefits from reduced ramping of thermal units;
6. The use of ten-minute time steps in the model instead of the 5-minute dispatches that are actually used in the EIM that should reduce potential variation in the model.
7. Modeling of hydro units constrained to monthly and daily budgets from actual generation data during a normal water year.

Staff concludes that by employing conservative assumptions and modeling approaches, the study produces quantified benefits that are modest yet sufficient to cover the proposed level of investment.

In evaluating E3's level of expertise, Staff found that they have substantial experience performing similar benefit studies for PacifiCorp, Puget Sound Energy, Arizona Public Service, NV Energy, and Portland General Electric Company, all utilities in the WECC that are actively participating or planning to participate in the EIM. In all cases, E3 used PLEXOS, a proprietary sub-hourly production cost modeling software widely used by utilities, regulators and system operators to model power markets. Because of this experience, E3 has been able to leverage its model from past projects to conduct Idaho Power's benefit study. Staff believes the repetition and layers of additional review have likely resulted in methodology improvements and more robust results.

Cost Analysis

The Company provided cost estimates for two purposes: (1) to perform a cost/benefit analysis; and (2) to book expense in a deferral account for future recovery. In its Application, Idaho Power requested the Commission to issue an order "authorizing the Company to recover, in a future rate proceeding, the estimated incremental costs of joining the EIM." Application at 5. Staff analyzed the estimated incremental costs of joining the EIM and has concluded that the basis used to establish the estimates are sound and a good approximation of actual cost for purposes of the cost/benefit analysis. However, Staff believes they lack rigor and certainty for determining recovery through rates, as described further below.

The cost of participating in the EIM include both upfront and ongoing annual costs as summarized in the following table:

Cost Summary (millions $)	Upfront Costs	Ongoing Annual Costs
Startup Expense	1.73	
Software Integration Cost	7.88	
Metering Investment	1.48	
Labor for Operations		0.836
CAISO Market and Software Cost		0.786
Total	11.09	1.622

The Company estimates about $11 million in total upfront cost and $1.6 million in annual ongoing cost. Staff requested a breakdown, description, and basis for each of the estimates. Other than a contract for project management services, Staff found almost all of the cost figures were based on projections and on scopes of work to be determined later. From the perspective of cost versus benefit, Staff concluded that a reasonable margin of error in estimated cost will not drastically effect the outcome of the analysis.

However, Staff believes it is not appropriate to use these cost estimates for rate recovery. First, Staff believes that the cost estimates fall short of the "known and measureable" standard. *See* Idaho Code §61-502. This is based on the Company's lack of prior experience operating in an EIM-like market and because cost estimates were developed without complete scopes of work and use of a rigorous bidding process. Second, the Commission reserves the right to review prudently incurred actual cost unless the investment is under special circumstances. *See* Idaho

Code §61-503. Providing cost pre-approval removes the incentive for the Company to implement a project in a prudent least-cost manner by removing the possibility of non-recovery of imprudently incurred actual cost. Accordingly, Staff recommends deferral of costs until actual costs can be determined and reviewed for prudency.

<u>Revenue Requirement Net Impact Analysis</u>

The Company's revenue requirement net impact analysis is used to determine the financial viability of the project. It calculates the impact to the Company's revenue requirement based on proposed implementation costs and benefits and costs quantified in the E3 baseline scenario. Staff reviewed the analysis to ensure it was accurate and augmented it to better understand the payback period. Staff found that the analysis was reasonably accurate showing positive net benefits (negative revenue requirement impact) in approximately five years with a total net benefit of $4.4 million over ten years. A copy of Staff's modified version of the analysis is provided as Attachment A to these comments.

Intangible Benefits

As previously mentioned, several intangible benefits were not included in the benefit analysis. Two of these are described in more detail below: reduced congestion, and reduced reserves and improved reliability. Although difficult to quantify now, these benefits could become significant in the future, especially if developments dynamically transform electricity wholesale markets across the west. Developments include enhanced ability to comply with potential state and federal environmental regulations, an EIM with widespread participation, and the potential formation of a WECC-wide regional transmission organization (RTO).

<u>Benefits from Reduced Congestion</u>

Staff has concluded that EIM benefits from the elimination of curtailments due to congested flow paths is very small at this time. Idaho Power claims that the EIM provides a benefit by eliminating curtailment on congested flow paths during late spring to summer, when maintaining system reliability requires higher cost resources to meet Idaho Power customer load. The EIM accomplishes this by avoiding resource dispatch into already congested areas due to broader visibility across the grid and better planning and management of congestion across more of the region's transmission system. (Anderson Direct at 11-12). However, based on Staff's analysis of curtailment events over the past year, the potential annual savings to Idaho Power is not material.

Staff based its assessment on a Company production request response that provided a list of curtailed energy purchases attributable to transmission path congestion over the past year. From this, Staff determined potential benefits from reduction in curtailment of the type that the EIM could resolve. Staff observed that the total dollar amount of energy that was curtailed was only about $5,000. Even if the price of replacement energy was double the amount that was curtailed, this would only amount to about a $5,000 annual savings. Staff further observed that most curtailments occurred during winter and early spring which were resolved using Company hydropower when it is more abundant and inexpensive. Curtailments during late spring and summer months were also replaced by Company hydro generation, and were thus more expensive because they, "[create] less opportunity and 'fuel' for generation in the future." (Company Response to Staff Production Request No. 7). However, only about a third of the total curtailed energy for the year occurred during late spring and summer months which contradicts Company claims that this is when most congestion occurs. (Anderson Direct at 11-12).

In Company Response to Staff Production Request No. 7, the Company also provided data showing about a 70% reduction in WECC-wide tag curtailments due to unscheduled flow events since 2014 when the EIM was first implemented. Although there appears to be reductions of curtailments from congestion across the region possibly attributable to an EIM, Staff believes that the incremental potential savings specific to Idaho Power's balancing area is very small at this time.

<u>Benefits from Reduced Reserves and Improved Reliability</u>

Idaho Power's participation in the EIM may hold significant benefits in the form of reduced reserves by sharing balancing resources across a wider footprint. The Company did not try to quantify the potential financial benefits to reliability and reduction of reserves in its benefit calculation. Staff agrees that separating the benefits between participating Balancing Authorities (BA) would be difficult. However, Staff believes the importance of this benefit should not be underestimated for three reasons: (1) Idaho Power is approaching the limit in integrating renewable resources into its system; (2) the Company may be required to carry additional reserves as bilateral market liquidity decreases from increased EIM participation by other utilities; and (3) there is the potential for reduction in wind and solar integration charges due to increased diversity and sharing of balancing resources.

First, Idaho Power asserts that its capability to integrate variable resources is at its limit. (Anderson Direct at 5). According to the Company, current and future renewable generation portfolio is as shown in the table below.

Renewable Installed Nameplate Capacity (MW)	**Current (as of 10/26/16)**	**Future Signed Contracts installed within 1 Year**	**Total**
Wind Power	678	56	734
Solar Power	50	234	284
Total	**728**	**290**	**1018**

Idaho Power stated in its 2013 Wind Integration Study report in Case No. IPC-E-13-22 that dispatchable thermal and hydro generation will reach its limit to provide balancing reserves beyond 800 MW of wind generation penetration especially during periods of low demand. If true, the Company will be close to its stated limit by the end of next year and may be over its functional limit with the amount of additional solar generation that has interconnected since then and wasn't included in the study. Given that Idaho Power is required to take all additional Public Utility Regulatory Policies Act of 1978 (PURPA) generation, the Company may at times need to increase curtailment or be at risk for reduced reliability.

One method to address some of the need for reserves is through an EIM. Because an EIM can quickly dispatch generation across a larger footprint, it can reduce the need for the Company to use its own resources to resolve imbalances leaving more of its own capacity to provide regulation reserves. In a National Renewable Energy Laboratory (NREL) study of the western interconnection, it showed that an EIM operating in the Northern Tier Transmission Group (NTTG) footprint could reduce average net reserves by one third; and for a WECC-wide EIM footprint, the reduction could be as much as one half and still operate reliably.[3] In addition, E3 in a previous study for Pacific Gas and Electric (PGE) estimated a $0.8 million savings from flexibility of reserves by joining an EIM. (Exhibit 4, Anderson Direct at 7).

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[3] National Renewable Energy Laboratory (2011), *Flexibility Reserve Reductions from an Energy Imbalance Market with High Levels of Wind Energy in the Western Interconnection, pp. 35-38.*

A second consideration is the impact of increased EIM participation on bilateral markets for reserves. According to the Company, it must carry additional reserves because there are fewer resources available in the bilateral market that the Company has typically used to resolve hour-ahead imbalances. (Anderson Direct at 6). This could be a result of differences in EIM timing requirements which require offers to be made earlier than bilateral trade deadlines. (Company Response to Staff Production Request No. 11). If the reduction in reserves is correlated to the expansion of the EIM, Staff believes that utilities that do not participate could incur increased power costs in the long term.

Finally, there is the potential for reduction in wind and solar integration charges by joining an EIM. Staff has previously commented "that downward pressure on integration costs will occur as forecasting improves, as shorter real-time markets develop (e.g., intra-hour trading, 15-minute scheduling, five minute dispatch), as energy imbalance markets develop, and as new technologies evolve, including energy storage." *See* Case No. IPC-E-13-22, Staff Comments at 6. Reduced wind and solar integration charges would be a benefit to renewable energy providers having spillover effects in the form of economic development in local communities where they are located but would not result in a benefit to Idaho Power customers.

Although direct benefits for reduced reserves were not included in the financial benefit calculation, Staff believes it is an important consideration and should not be discounted given the relative amount of renewables in Idaho Power's system, the potential for reduced bilateral market liquidity requiring additional reserves, and the possible opportunity for lower wind and solar integration charges.

Methods of Cost Recovery

Idaho Power seeks to defer its incremental costs related to participation in the western EIM to allow the Company to match benefits customers receive with the costs incurred by the Company. The Company proposes that deferral of the Idaho jurisdictional share of these start-up and associated incremental labor costs to a regulatory asset continue until no earlier than April 2018, or the time at which such costs can be amortized into customer rates. Idaho Power also proposes an amortization period of ten years to ensure that annual revenue requirements will only reflect positive net benefits. Idaho Power also seeks assurance that the upfront costs required to participate in the western EIM are eligible for recovery when requested.[4] The Company claims that absent the ability to recover the up-front and ongoing costs, it will suffer negative financial impacts. *See* Tatum Direct at 12-16. The Company states that absent deferral the estimated negative financial impact would total $9.1 million on a net present value basis for the 2016-2025 forecast period. *See* Company Exhibit 2. For that same period, the Company estimates customers would receive an estimated $19.3 million on a net present value basis through reduced Net Power Supply Expense benefits flowed through the Power Cost Adjustment.

Staff recommends that the Commission authorize a deferral of the start-up and incremental costs associated with joining the western EIM during the start-up period. Staff believes that the long-term benefits of the program will likely outweigh the cost. Since the customers will be the recipient of the benefits, it is appropriate for customers to also bear the costs, and that a deferral account is the appropriate mechanism to capture the initial costs until such time as the benefits begin to flow to customers.

The Company anticipates incremental labor costs of approximately $836,000 associated with the addition of six full-time employees required for the Company's participation in the western EIM. In addition, there will be ongoing market and hosted software fees of approximately $786,000 per year upon joining the western EIM, beginning in April 2018. The Company estimates that these O&M expenses for 2018 will be $1.39 million, and for 2019 and 2020 will be $1.62 and $1.67 million, respectively. The Company proposes deferral of the Idaho jurisdictional share of incremental labor associated with employees dedicated entirely to EIM activities until customer rates are adjusted to reflect the annual amortization of the requested deferral balance.

Staff proposes that the Company cease booking costs to the deferral account at the earlier of when the Company requests recovery of EIM costs and the deferral balance, or the end of 2018. After the go-live date to participate in the EIM, these costs are similar to any other O&M cost that may be included for recovery in a rate proceeding. The existing rate case process will allow the Company the opportunity to recover these costs. Therefore, Staff believes that continuing to book the ongoing incremental O&M costs, including the incremental labor costs, in

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[4] Because timing of a future general rate case is unknown, the Company may propose an interim rate recovery method in order to appropriately match the level of cost recovery with the provision of customer benefits.

the deferral account past the go-live event would not be prudent. Recognizing the timing of rate proceedings may differ from the go-live date of April 2018, Staff recommends December 2018 be the latest possible deferral month.

Staff agrees with the Company that the initial costs should be amortized over a ten-year period. Although the Company asserts that the participation in the EIM is "indefinite," Staff believes that using a ten-year amortization period will result in a proper matching of costs and benefits. This is bolstered by the Company's NPV revenue requirement cost/benefit analysis which reflects positive net benefits over a ten-year period.

The estimated capital costs are predominately the software integration cost of $7.88 million. Normally these costs would be amortized over seven years. However, the metering investment of $1.48 million costs are recorded in FERC accounts that are normally depreciated over 25 or 34 years, depending on the FERC account. Staff believes that a ten-year amortization period represents a good blend of the varying depreciation periods. Staff believes that customers will not be harmed by a ten-year amortization period.

The Company proposes that the deferred amounts be recorded to FERC Account 182.3, Other Regulatory Assets, and that the amortization of the deferral be recorded to FERC Account 407.3, Regulatory Debits. Staff concurs with this proposal.

The Company has also requested a carrying charge be applied to the deferral at the customer deposit rate, and once amortization begins, that a carrying charge at the Commission approved rate of return be applied to the unamortized balance. Staff proposes that no carrying charge apply during the deferral period. Once amortization begins, Staff proposes that a carrying charge be applied to only the capital portion of the unamortized balance at the Company's overall rate of return.

Staff is opposed to a carrying charge. In this case, Staff is confident that the ability to defer the costs for future recovery will provide sufficient benefit to the Company over normal accounting statement without a carrying charge. Additionally, Staff believes that not having a carrying charge could further incent the Company to minimize costs. If normal ratemaking treatment was followed, the Company would expense the Operation and Maintenance (O&M) costs in the year in which they occur, and the capital costs would be booked to plant in service and depreciation at the Commission approved rates would begin when the plant is placed in service. In the next general rate case, the prudently incurred ongoing O&M costs would be built into rates, and the prudently incurred undepreciated capital items would be added to rate base to earn a return. Allowing the Company to defer these costs preserves all the initial costs for future recovery from customers. Once amortization begins, Staff believes that receiving a carrying charge only on the capital portion of the deferral balance more closely follows traditional ratemaking treatment.

Finally, as previously discussed, the Company has requested that the Commission authorize the Company to recover in a future rate proceeding the estimated incremental costs of joining the EIM. Because estimated costs can vary, Staff believes prudency review of actual costs should be determined in a future case. At that time, actual recovery of prudently incurred costs would be determined.

STAFF RECOMMENDATIONS

Staff recommends that the Commission acknowledge the potential for long-term benefits associated with the Company's participation in the Energy Imbalance Market. In addition, Staff recommends the following:

1. The Commission approve an Accounting Order authorizing deferral of incremental costs associated with participation in the Energy Imbalance Market and for deferrals to cease by December 2018.
2. The Company utilize the proposed accounts with the incremental EIM costs charged to Account 182.3 (Other Regulatory Assets) and the amortization charged to Account 407.3 (Regulatory Debits).
3. The Commission authorize an amortization period of ten years.
4. The Commission authorize no carrying charge during deferral.
5. During amortization, the Commission authorize a carrying charge to be applied only to the capital portion of the unamortized deferral balance at the Company's current rate of return.
6. The Commission allow recovery of actual costs in a future rate proceeding only after a thorough review to ensure costs are reasonable and prudently incurred.

Respectfully submitted this 15th day of December 2016.

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Idaho Power Company
EIM Participation
Idaho Jurisdictional Revenue Requirement

	RATE BASE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Electric Plant in Service										
2	Intangible Plant	0	0	5,220,884	7,541,278	7,541,278	7,541,278	7,541,278	7,541,278	7,541,278	7,541,278
3	Production Plant	0	0	979,649	1,415,048	1,415,048	1,415,048	1,415,048	1,415,048	1,415,048	1,415,048
4	Total Electric Plant in Service	0	0	6,200,533	8,956,326	8,956,326	8,956,326	8,956,326	8,956,326	8,956,326	8,956,326
5	Less: Accumulated Depreciation	0	0	31,074	75,958	120,841	165,725	210,609	255,493	300,377	345,261
6	Less: Amortization of Other Plant	0	0	745,841	1,823,166	2,900,491	3,977,817	5,055,142	6,132,467	7,209,793	7,541,278
7	Net Electric Plant in Service	0	0	5,423,619	7,057,202	5,934,993	4,812,784	3,690,574	2,568,365	1,446,155	1,069,787
8	Less: Accumulated Deferred Income Taxes	0	0	634,133	1,347,521	1,505,159	1,528,077	1,283,277	903,926	523,310	273,253
9	Add: Conservation - Other Deferred Prog	0	0	0	0	0	0	0	0	0	0
10	**TOTAL COMBINED RATE BASE**	0	0	4,789,486	5,709,681	4,429,834	3,284,706	2,407,297	1,664,438	922,845	796,533
	NET INCOME										
11	Operating Revenues										
12	Sales Revenues	0	0	4,134,737	5,512,983	5,512,983	5,512,983	5,512,983	5,512,983	5,512,983	5,512,983
13	Operating Expenses										
14	Operation and Maintenance Expenses	373,099	1,165,391	2,379,389	2,800,211	2,846,783	2,894,751	2,944,158	2,995,046	3,047,460	3,101,445
15	Depreciation Expenses	0	0	31,074	44,884	44,884	44,884	44,884	44,884	44,884	44,884
16	Amortization of Limited Term Plant	0	0	745,841	1,077,325	1,077,325	1,077,325	1,077,325	1,077,325	1,077,325	331,485
17	Taxes Other Than Income	0	0	30,684	44,542	44,765	44,989	45,214	45,440	45,667	45,895
18	Provision for Deferred Income Taxes	0	0	1,268,267	158,509	156,768	(110,931)	(378,670)	(380,031)	(381,201)	(118,912)
19	Federal Income Taxes	(122,358)	(382,190)	(988,956)	297,090	283,294	505,753	727,775	712,226	696,010	679,116
20	State Income Taxes	(23,505)	(73,420)	2,563	(8,886)	(11,329)	63,240	137,730	134,904	131,929	128,801
21	Total Operating Expenses	227,236	709,781	3,468,859	4,413,675	4,442,490	4,520,011	4,598,416	4,629,794	4,662,073	4,212,714
22	Operating Income	(227,236)	(709,781)	665,878	1,099,308	1,070,493	992,972	914,567	883,189	850,909	1,300,269
23	Add: IERCO Operating Income	0	0	0	0	0	0	0	0	0	0
24	**Consolidated Operating Income**	(227,236)	(709,781)	665,878	1,099,308	1,070,493	992,972	914,567	883,189	850,909	1,300,269
25	Authorized Rate of Return	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%
26	Earnings Impact	227,236	709,781	(289,424)	(650,527)	(722,308)	(734,794)	(725,354)	(752,364)	(778,374)	(1,237,661)
27	Net-to-Gross Tax Multiplier	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642
28	**Revenue Requirement**	**373,122**	**1,165,461**	**(475,235)**	**(1,068,165)**	**(1,186,030)**	**(1,206,532)**	**(1,191,030)**	**(1,235,381)**	**(1,278,090)**	**(2,032,240)**
29	**NPV OF REV REQ IMPACT - 10 YRS**	**$ (4,375,102)**									
	n =	1	2	3	4	5	6	7	8	9	10
30	**NPV of REV REQ Impact over n years**	**$ 345,931**	**$ 1,347,722**	**$ 968,994**	**$ 179,777**	**$ (632,667)**	**$ (1,398,927)**	**$ (2,100,221)**	**$ (2,774,621)**	**$ (3,421,492)**	**$ (4,375,102)**

Attachment A
Case No. IPC-E-16-19
Staff Comments
12/15/16

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15TH DAY OF DECEMBER 2016, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF** IN CASE NO. IPC-E-16-19, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY