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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

KATHLEEN ANDERSON

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Kathleen Anderson. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Transmission and Energy Scheduling Leader in the Load Serving Operations Department.

Q. Please describe your educational background.

A. In December of 2000, I received a Bachelor of Administration degree in Finance from Boise State University in Boise, Idaho. In September of 2005, I earned a Master of Business Administration degree from the University of Phoenix.

Q. Please describe your work experience with Idaho Power.

A. In 2005, I was hired as a Business Analyst in Idaho Power's Delivery Finance Department. My primary responsibilities included reviewing and granting credit to entities wishing to conduct business under the Company's Open Access Transmission Tariff ("OATT"). In addition, I provided analyst support to the Company's Grid Operations Department, assisting with budgeting and other financial and accounting duties. In 2006, I transferred to the Grid Operations Department as an Operations Analyst and was responsible for all contractual obligations of the Company's OATT. In 2009, I became the System Operations Leader in the Grid Operations Department and oversaw all day-ahead and real-time activity conducted under the OATT, as well as all transmission contracts administered by the Grid Operations and Load Serving Operations Departments. In 2015, I was promoted to the Transmission and Energy Scheduling Leader where, in addition to my current duties, I assumed the oversight responsibility of the day-ahead balancing operators.

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

A. My testimony in this case will describe an Energy Imbalance Market ("EIM") and the costs and benefits associated with Idaho Power's participation in the western EIM.

I. ENERGY IMBALANCE MARKET

Q. Please describe an energy market.

A. An energy market facilitates the bilateral trading of energy between two parties by matching generation with load to maintain frequency of the grid. Purchases and sales, or trades, are typically executed for the mid-term (month or week), near-term (day), hour-ahead (next few hours), or real-time (current operating hour) and can be traded in blocks of 24 hours, heavy load (16 hours), or light load (8 hours).

Q. What is an energy imbalance?

A. Simply put, when the supply of energy does not equal the demand, energy imbalance occurs. Deviations in supply and demand occur in every hour, resulting in a mismatch between available electricity versus what is needed by consumers. To manage these energy imbalances within its Balancing Area ("BA"), Idaho Power relies on dispatches of internal resources and extra reserves.

Q. Are there other ways of solving energy imbalance?

A. Yes. In addition to managing imbalances within the Company's BA, Idaho Power has the opportunity to participate in an EIM and use neighboring grids and resources to help balance supply and demand more efficiently and cost-effectively.

Q. Please describe an EIM.

A. An EIM solves sub-hourly imbalances through an automated five-minute energy dispatch service across a broader footprint with more deployable resources available, providing a more efficient method for maintaining balance. It allows participants to buy and sell power closer to when the electricity is consumed, in increments as small as every five minutes, and allows system operators real-time visibility across neighboring grids, strengthening grid reliability.

Q. How does an EIM operate?

A. All BAs begin the hour with matched generation and forecasted load. As imbalances occur within the hour, resources within the EIM area can voluntarily provide bids to dispatch their facilities to manage these imbalances. The market operator of the EIM will automatically look across the expanded EIM region to determine the least-cost dispatch order and issue an operating target for each participating resource, resulting in the most economical bids available to meet these imbalances. The real-time optimization process determines the least-cost mix of resources and dispatches them to resolve these imbalances while also respecting limits on the transmission system to alleviate overloads or congestion.

Q. Does Idaho Power have the option of participating in an EIM?

A. Yes, Idaho Power has the option of participating in the western EIM. Idaho Power's BA is connected to PacifiCorp East and West and NV Energy, Inc.'s BAs, all of whom participate in and provide a direct tie to the western EIM.

Q. Are there any other organized markets Idaho Power could participate in that perform the same or a similar function as the western EIM?

A. No, not adjacent to the Company's BA. Idaho Power is a member of the Northwest Power Pool, which was attempting to form a voluntary generation dispatch market in the region but ended that initiative when a number of its members instead joined the western EIM. None of the other organized markets provide a direct tie to Idaho Power's BA.

Q. Could Idaho Power maintain its current practice for solving energy imbalance?

A. Yes, Idaho Power could continue to dispatch resources from within its BA and continue to carry additional reserves to manage energy imbalances. However, this approach restricts the available generation resources for other purposes, potentially resulting in higher costs for customers relative to EIM participation. In addition, the Company is at the limits of system integration capabilities given the proliferation of existing intermittent Public Utility Regulatory Policies Act of 1978 (PURPA) wind and anticipated solar generation beginning in 2016, making the current self-management of energy imbalance even more complex.

Q. How does continuing to carry additional reserves restrict the available resources for other purposes?

A. Carrying additional reserves to manage energy imbalance restricts the available resources for purposes such as serving load with potentially lower-cost resources or bilateral off-system energy sales. As the number of western EIM participants grows, the potential for Idaho Power to transact bilaterally decreases in real time as the Company moves closer to each operating hour. Consequently, Idaho Power must carry additional reserves or procure energy to reliably meet load. Prior to the advent of the western EIM, Idaho Power typically had the ability to procure energy for reserves 40 minutes from the start of the next operating hour. As more participants have entered the western EIM, fewer resources are available for Idaho Power's energy imbalance management, resulting in decreased liquidity in the real-time market for up to two hours prior to the next operating hour time horizon.

Q. What is the impact of decreased bilateral liquidity on Idaho Power's operations?

A. The further away from the operating hour the balancing is completed, the less accurate the forecast, resulting in an increase in regulatory-required reserves held by the BA due to the uncertainty. The outcome of the increase in purchases and decrease in off-system sales is increased Net Power Supply Expense ("NPSE") for customers.

Q. Please describe the western EIM.

A. The western EIM is a voluntary energy imbalance market service that was implemented by the California Independent System Operator ("CAISO") and PacifiCorp on November 1, 2014. Since then, NV Energy, Inc., entered the market and both Puget Sound Energy and Arizona Public Service Company will enter on October 1, 2016. As the market operator, CAISO has opened its advanced market systems by extending its existing infrastructure, offering EIM services to other BAs. The western EIM allows other participants to leverage the benefits of real-time balancing while also maintaining all of their existing authority.

Q. Who governs the western EIM?

A. When the western EIM was established, it was managed by CAISO's Board of Governors ("CAISO Board"). However, as the number of EIM entities grew, the need for an EIM governing board became apparent. Effective July 1, 2016, the CASIO Board appointed five members to the newly created EIM Governing Body who are financially independent from market participants and selected by a nominating committee made up of representatives from the following sectors: EIM entities, participating transmission owners, suppliers and marketers of generation, publicly-owned utilities, the body of state regulators, the EIM Transitional Committee, the ISO Board of Governors, and public interest and consumer advocate groups. Although the CAISO Board approved the initial five members, Governing Body members will approve future nominations. The EIM Governing Body will have delegated authority over the western EIM market rules.

In addition, the governance structure established an advisory body comprised of regulators in states that participate in the real-time market, creating a periodic stakeholder forum to discuss regional issues. In addition to the EIM Governing Body, CAISO and all EIM participants are required to include as part of their Federal Energy Regulatory Commission ("FERC") filed OATT an attachment that incorporates the general provisions, roles and responsibilities, operations, and compliance details specific to participation in an EIM. Public utilities defined under the Federal Power Act have the authority to provide transmission services under their OATT. Further, the Energy Policy Act of 2005 granted FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets. FERC provides jurisdiction over the sale of transmission capacity and wholesale electricity and regulates transmission services provided under a utility's OATT, including participation in an EIM when applicable.

Q. Does FERC require any other filings prior to entering into an EIM?

A. Yes. Idaho Power currently has market-based rate authority for transactions in its BA. FERC grants market-based rate authority to sellers who demonstrate they lack or have adequately mitigated horizontal and vertical market power, approving the seller's market-based rate tariff. Absent market-based rate authority, an energy seller must bid resources into the market at the determined default energy bid. As a participant in the EIM, Idaho Power would be required to file a request with FERC to evaluate whether it has market-based rate authority in the EIM market. FERC will determine if Idaho Power's market rates are just and reasonable and if it can charge market-based rates for energy sale transactions in the EIM market.

Q. Would Idaho Power be impacted if the Company does not obtain market-based rate authority within the western EIM?

A. If FERC determined Idaho Power had market power and did not obtain market-based rate authority, it would not have a material impact to Idaho Power's customers. Instead, the Company would bid resources in the market at the determined default energy bid for that resource. But, as a participant, a utility is paid the settled market price for the energy bid into the market whether it operates under market-based rate authority or a default energy bid.

Q. As a participant in the western EIM, does a utility lose autonomy over its generating resources?

A. No. EIM participants maintain operational control over their generating resources, retain all their obligations as a BA, and must still comply with all regional and national reliability standards. Also, BAs remain responsible for procurement or self-provision of reserves and other ancillary services and participation in the western EIM does not change North American Electric Reliability Corporation and Western Electricity Coordinating Council responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

Q. You stated that participation in the western EIM may potentially lower power supply costs due to an expected reduction in the need for reserves and increased efficiency of the transmission system. Are there other benefits the western EIM can provide its participants?

A. Yes, the western EIM helps participants by utilizing all resources within the EIM footprint and helps mitigate the intermittent nature of renewable energy. For example, if a utility is generating excess solar, rather than backing down its own baseload resources, the market operator can use that western EIM participant's output to serve customers in other participants' service territories and vice versa, allowing the use of a reduced carbon emission resource valued at the market price.

In addition, western EIM participants enhance reliability for customers through broader visibility across grids and with better planning and management of congestions across more of the region's transmission system. Currently, Idaho Power experiences significant congestion on the Northwest to Idaho path during the late spring through summer operational periods. This congestion is often the result of unscheduled flow on the system. When flows on the path are high, Idaho Power must sometimes curtail energy scheduled on that path to maintain system reliability. Curtailing of energy purchases made by Idaho Power for load service to its customers can increase NPSE as a higher cost resource may be required to serve customers. In an EIM, resources are dispatched such that congestion on transmission paths is reduced while also not dispatching resources into already congested areas, providing enhanced reliability and minimizing curtailments of energy scheduled on those paths. Because participants are required to enter the operating horizon balanced, the resources utilized to meet imbalances are dispatched to avoid constraints, potentially providing additional operating benefits to customers.

Q. You indicated the western EIM is expected to provide cost savings to CAISO and four other utilities, benefiting consumers in eight western states. Would the addition of participants in the western EIM hinder the cost savings existing participants are experiencing?

A. No. The CAISO approach is scalable, meaning that new entities can be added incrementally when they are ready, bringing benefits to both new customers and existing customers of the western EIM.

Q. How does added participation bring benefits to participants of the western EIM?

A. As fluctuations in supply and demand occur, the market system will automatically find the best resource from across the larger region to meet immediate power needs. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion on transmission lines, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

The wider the geographic area, the better the benefits participants of the western EIM are expected to receive.

Q. As of October 1, 2016, the western EIM participants will include PacifiCorp, NV Energy, Inc., Puget Sound Energy, and Arizona Public Service Company. Are there any other utilities that have announced plans to join the western EIM?

A. Yes. Portland General Electric Company announced its participation with operations expected to begin in October 2017 and, contingent upon necessary regulatory approvals, Idaho Power has signed an implementation agreement with CAISO ("Agreement"), bringing the total to six utility participants in addition to CAISO and its participants, while several others are currently exploring participation in the market. A copy of the Agreement is provided as Exhibit No. 3. Under the Agreement, CAISO will provide energy imbalance services to Idaho Power by extending and modifying its existing real-time market system effective April 2018. On June 28, 2016, FERC accepted the Agreement for filing.

II. IDAHO POWER'S PARTICIPATION IN THE WESTERN EIM

Q. Please explain Idaho Power's decision to enter into the Agreement with CAISO for participation in the western EIM.

A. Idaho Power's decision to enter into the Agreement was based on the results of a benefits study that indicated participation in the western EIM real-time energy market could result in efficiencies that translate into NPSE savings for the Company's customers. Idaho Power's customers are expected to see benefits from the market, including lower NPSEs, better visibility for system operations in the Western Interconnection, and improved integration of intermittent renewable resources.

Q. Please describe the benefits study performed for Idaho Power.

A. In the fall of 2015, Idaho Power engaged Energy and Environmental Economics, Inc. ("E3") to perform an economic benefits study of Idaho Power's participation in the western EIM. The study, *Idaho Power Company Energy Imbalance Market Analysis*, is included as Exhibit No. 4 to my testimony. The focus of the analysis performed was to provide consistent, conservative estimates of NPSE savings to Idaho Power to be used for evaluation of participation in the EIM. To do so, E3 used a production simulation model that compared the Company's real-time generation costs as an EIM participant, as well as any power supply related revenues or costs from transactions with other EIM participants, against a scenario in which Idaho Power was not a participant in the western EIM, or a business as usual case.

Q. How does a production simulation model estimate economic benefits for a utility?

A. E3 used PLEXOS, a sub-hourly production cost model that simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. For Idaho Power's participation, the software simulated sub-hourly operations in the Western Interconnection for the year 2020 and assumed seven western EIM participants, those that are either currently participating in or who have announced plans to join the western EIM. PLEXOS uses a three-stage sequential simulation process to model day-ahead, hour-ahead, and real-time operations to represent the different time horizons of actual power system operations.

To quantify sub-hourly dispatch savings from Idaho Power's participation in the western EIM, E3 first ran a real-time business as usual case that held energy transfers between non-participating BAs (including Idaho Power) equal to the scheduled levels from the hour-ahead simulation. The business as usual run also allowed the western EIM participants to transact with other EIM participating BAs in the same real-time market, subject to transmission transfer limits, in order to replicate a scenario that would exist if Idaho Power was not a participant of the western EIM. Next, E3 took the results from the business as usual case and allowed the Company to transact power within the hour with other western EIM participants. The difference between the two scenarios resulted in western EIM-wide savings due to increased flexibility and decreased real-time production costs for the region ("Base Scenario"). E3 then divided the benefits between Idaho Power and the other western EIM participants based on the change in their generation costs and their net purchases and sales in real time through the western EIM.

Q. Does E3's analysis assume Idaho Power will obtain its market-based rates as a participant in the western EIM?

A. As described earlier in my testimony, a utility is paid the market price for its generation bid into the market whether it operates under market-based rate authority or a default energy bid. The benefits analysis performed by E3 values energy at the estimated cost of production as determined by the utility, using a conservative approach to estimate the cost of production that would apply under either scenario.

Q. Please describe the assumptions used in the Base Scenario.

A. The Base Scenario described above included renewable resource development to meet current Renewable Portfolio Standards ("RPS") and projected renewable build out for 2020. It assumed a 33 percent RPS for California, a 15 percent renewable penetration for Idaho Power, and an average 15 percent renewable share for other Northwest BAs.

Q. Were any additional scenarios analyzed besides the Base Scenario?

A. Yes. E3 ran three alternative scenarios that assume (1) Arizona Public Service Company and Portland General Electric Company have not joined the EIM by 2020; (2) the following early coal retirements: Valmy 1, Valmy 2, Reid Gardner 4, Navajo 1, San Juan 2, and San Juan 3 ("Early Coal Retirement Scenario"); and (3) a higher renewable penetration in the west, including a 40 percent RPS for California, a 20 percent renewable penetration for Idaho Power, and an average 20 percent renewable share for other Northwest non-western EIM participants' BAs (High RPS Scenario).

Q. What are the NPSE savings that resulted from each scenario?

A. The Base Scenario resulted in sub-hourly dispatch cost savings for Idaho Power's participation in the western EIM of $4.5 million per year, while the alternative scenarios resulted in a range of estimated savings per year between $4.1 and $5.1 million. More detail on each scenario can be found in Exhibit No. 4 to my testimony.

Q. You mentioned that in addition to lower costs, participation in the western EIM may reduce the need to hold additional flexible reserves and result in a more efficient use of the transmission system, enhancing reliability. Has E3 quantified the savings that would result from those added benefits?

A. No. The study does not quantify any potential customer reliability benefits from western EIM participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major outage for customers, nor does it quantify savings arising from the flexibility reserve reductions, which could further reduce NPSE.

Q. How will Idaho Power quantify and demonstrate the benefits achieved as a participant in the western EIM?

A. On a quarterly basis, CAISO releases its *Quantifying EIM Benefits* report that quantifies the estimated gross benefits achieved by western EIM participants for the previous calendar quarter. The methodology used to estimate quarterly benefits is described in CAISO's *EIM Quarterly Benefit Report*

Methodology document, included as Exhibit No. 5 to my testimony.

Q. Please describe the methodology CAISO uses to estimate quarterly benefits.

A. CAISO determines the total EIM benefit by calculating the cost savings of the EIM dispatch as compared to a counterfactual without EIM dispatch. The counterfactual dispatch meets the real-time load imbalance in each BA without allowing for transfers among neighboring EIM BAs. Exhibit No. 5 to my testimony describes in detail the methodology used each quarter to estimate participant benefits.

Q. What is included in the quarterly *Quantifying EIM Benefits* report provided to participants by CAISO?

A. The quarterly report quantifying EIM benefits includes the estimated gross benefits by EIM participant and quarter. The report also describes any significant contributions to the EIM benefits that were experienced by participants. Included as Exhibit No. 6 to my testimony is CAISO's 2016 quarter two report, dated July 28, 2016. As can be seen in the report, the western EIM benefits for the second quarter of 2016 are estimated to be $23.60 million, bringing the total benefits to $88.19 million since expansion of the real-time market to BAs outside of CAISO. As a participant in the western EIM, Idaho Power's benefits would be calculated and identified in CAISO's quarterly report.

III. COSTS ASSOCIATED WITH IDAHO POWER'S PARTICIPATION IN THE WESTERN EIM

Q. Are there any costs associated with participation in the western EIM?

A. Yes, participation in the western EIM will require both upfront and ongoing incremental costs, software integration costs, and metering investments.

Q. Please describe the incremental costs.

A. Under the Agreement with CAISO, the Company is required to pay a fixed implementation fee totaling $540,000, subject to completion of six specific milestones, to compensate for costs attributable to CAISO's effort to configure its real-time market systems to incorporate Idaho Power into the western EIM. The implementation fee is comprised of six $90,000 payments that coincide with CAISO's project milestones that will occur between the time the Agreement was signed and the time Idaho Power becomes an active participant in the western EIM. In addition to the implementation fee, the Company anticipates start-up costs associated with the issuance of a Request for Information/Proposal, outside consulting and legal counsel, and the hiring of six full-time employees dedicated entirely to upfront and ongoing EIM activities. Idaho

Power anticipates approximately $1.73 million in upfront incremental costs prior to an April 2018 western EIM entrance date.

Q. What software integration costs result from participation in the western EIM?

A. Software integration costs represent more than half of the expected capital costs as participation in the western EIM will require software and system interfaces that allow for transacting with CAISO. Because Idaho Power does not have sufficient internal expertise with the CAISO market, the Company has engaged a system integrator that will provide consulting services throughout the integration process. In addition to the costs of utilizing a system integrator, Idaho Power will be required to procure a bid-to-bill system, which is anticipated to be a hosted solution. The bid-to-bill system will allow submission of offers into the market as well as the use and receipt of large amounts of data required for the purpose of energy settlements.

Q. How much does Idaho Power estimate it will spend on software integration to enable the Company to participate in the western EIM?

A. Idaho Power anticipates spending approximately $7.88 million on software integration.

Q. Please describe the investments in metering equipment the Company will be required to make prior to participation in the western EIM.

A. The majority of the meters on Idaho Power's generating units cannot provide the data granularity that will be required for CAISO settlement purposes. The Company will examine all existing meters and determine whether or not they meet CAISO's requirement for providing five-minute, 15-minute, or 60-minute data and update as necessary. In addition, Idaho Power has identified a few instrument transformers feeding these generation meters and some instrument transformers at several power plant locations that are not revenue quality and will need to be replaced.

Q. Will revenue quality meters be required on generation units that Idaho Power chooses not to be available for dispatch in the western EIM?

A. Yes. Even though Idaho Power will identify which Company-owned generating units will be considered participating units and available for dispatch in the market and which will be non-participating units, CAISO requires that both are able to provide interval data but at different levels of granularity.

Q. What is the Company's estimate of the total costs of all required metering investments?

A. Idaho Power estimates investing approximately $1.48 million in required metering equipment for participation in the western EIM.

Q. Does the benefits study performed by E3 factor in the costs Idaho Power expects to incur as a participant in the western EIM?

A. No. Company witness Mr. Tatum has performed a revenue requirement analysis that describes the net impact of the upfront and ongoing costs and NPSE benefits associated with participation in the western EIM and the Company's proposed accounting treatment of those costs.

IV. CONCLUSION

Q. Please summarize your testimony.

A. Idaho Power currently manages energy imbalances within its BA. However, participation in the western EIM to manage supply and demand could result in lower costs due to the reduction in the need for reserves and the efficient use of the transmission system, while also helping to reduce carbon emissions and more efficiently use and integrate intermittent renewable energy. Absent Idaho Power's participation in the western EIM, market liquidity in the bilateral real-time market will likely continue to decline and additional reserves will likely need to be maintained, resulting in increased NPSE for the Company's customers. It is estimated that

Idaho Power's participation in the western EIM would result in sub-hourly dispatch cost savings of $4.1-$5.1 million per year, resulting in a lower-priced energy imbalance management option.

Q. Does this complete your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Kathleen Anderson, 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 Transmission and Energy Scheduling Leader in the Load Serving Operations 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 19th day of August 2016.

Kathleen Anderson

SUBSCRIBED AND SWORN to before me this 19th day of August 2016.

CHRISTA S. BEARRY
NOTARY
PUBLIC
STATE OF IDAHO

Notary Public for Idaho
Residing at: Boise, Idaho
My commission expires: 02/04/2021

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-19

IDAHO POWER COMPANY

ANDERSON, DI TESTIMONY

EXHIBIT NO. 3

ENERGY IMBALANCE MARKET
IMPLEMENTATION AGREEMENT

This Implementation Agreement ("Agreement") is entered into as of April 6, 2016, by and between Idaho Power Company, an Idaho corporation ("IPCO"), and the California Independent System Operator Corporation, a California nonprofit public benefit corporation ("ISO"). IPCO and the ISO are sometimes referred to in the Agreement individually as a "Party" and, collectively, as the "Parties."

RECITALS

A. WHEREAS, IPCO has determined there is an opportunity to secure benefits for IPCO's customers through improved dispatch and operation of IPCO's generation fleet and through the efficient use and continued reliable operation of existing and future transmission facilities and desires to participate in the energy imbalance market operated by the ISO ("EIM");

B. WHEREAS, the ISO has determined there are benefits to ISO market participants through greater access to energy imbalance resources in real-time and through the efficient use and reliable operation of the transmission facilities and markets operated by the ISO, and desires to expand operation of the EIM to include IPCO;

C. WHEREAS, IPCO acknowledges that the rules and procedures governing the EIM are set forth in the provisions of the ISO tariff as filed with the Federal Energy Regulatory Commission ("FERC") and that participation in the EIM requires corresponding revisions to IPCO's Open Access Transmission Tariff ("IPCO Tariff") and the execution of associated service agreements; and

D. WHEREAS, the Parties are entering into this Agreement to set forth the terms upon which the ISO will timely configure its systems to incorporate IPCO into the EIM ("Project") on or before April 1, 2018 (" Implementation Date").

NOW THEREFORE, in consideration of the mutual covenants contained herein, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

AGREEMENT

1. <u>Effective Date and Term</u>.

(a) This Agreement shall become effective upon the date the Agreement is accepted, approved or otherwise permitted to take effect by FERC, without condition or modification unsatisfactory to either Party ("Effective Date").

(b) In the event FERC requires any modification to the Agreement or imposes any other condition upon its acceptance or approval of the Agreement, each Party shall have ten (10) days to notify the other Party that any such modification or condition is unacceptable to that Party. If no Party provides such notice, then the Agreement, as modified or conditioned by FERC, shall take effect as of the date determined under Section 1(a). If either Party provides such notice to the other Party, the Parties shall take any one or more of the following actions: (i) meet and confer and agree to accept any modifications or conditions imposed by such FERC order; (ii) jointly seek further administrative or legal remedies with respect to such FERC order, including a request for rehearing or clarification; or (iii) enter into negotiations with respect to accommodation of such FERC order, provided however, if the Parties have not agreed to such an accommodation within thirty (30) days after the date on which such FERC order becomes a final and non-appealable order, such order shall be deemed an adverse order and the Parties shall have no further rights and obligations under the Agreement.

(c) The term of the Agreement ("Term") shall commence on the Effective Date and shall terminate upon the earliest to occur of (1) the date FERC permits all necessary revisions to the IPCO Tariff to take effect and the service agreements under such tariff and the ISO tariff necessary for the commencement of IPCO's participation in the EIM have taken effect; (2) termination in accordance with Section 2 of this Agreement; or (3) such other date as mutually agreed to by the Parties ("Termination Date").

(d) This Agreement shall automatically terminate on the Termination Date and shall have no further force or effect, provided that the rights and obligations set forth in Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect as provided therein.

2. Termination.

(a) The Parties may mutually agree to terminate this Agreement in writing at any time. In addition, either Party may terminate this Agreement in its sole discretion after conclusion of the negotiation period in Section 2(b) or as provided in Section 2(d) or 2(e) as applicable.

(b) If either the ISO or IPCO seeks to unilaterally terminate this Agreement, it must first notify the other Party in writing of its intent to do so ("Notice of Intent to Terminate") and engage in thirty (30) days of good faith negotiations in an effort to resolve its concerns. If the Parties successfully resolve the concerns of the Party issuing the Notice of Intent to Terminate, the Party that issued such notice shall notify the other Party in writing of the withdrawal of such Notice ("Notice of Resolution").

(c) At the time the Notice of Intent to Terminate is provided, or any time thereafter unless a Notice of Resolution is issued, IPCO may provide written notice directing the ISO to suspend performance on any or all work on the Project for a specified period of time ("Notice to Suspend Work"). Upon receipt of a Notice to Suspend Work, the ISO shall: (1) discontinue work on the Project; (2) place no further orders with subcontractors related to the Project; (3) take commercially reasonable actions to suspend all orders and subcontracts; (4) protect and maintain the work on the

Project; and (5) otherwise mitigate IPCO's costs and liabilities for the areas of work suspended. The ISO will not invoice IPCO pursuant to Section 4(c) of this Agreement for any milestone payment following the issuance of a Notice to Suspend Work. To the extent a Notice of Resolution is issued pursuant to Section 2(b), the Notice to Suspend Work in effect at the time shall be deemed withdrawn and the ISO shall be entitled to invoice IPCO for any milestone completed as specified in Section 4(c) of this Agreement and IPCO shall pay such invoice pursuant to Section 4.

(d) Any time after thirty (30) days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a Notice of Resolution, the ISO may terminate this Agreement by providing written notice to IPCO that it is terminating this Agreement ("Termination Notice") effective immediately. The ISO may terminate this Agreement under the terms of this Section 2(d) at its sole discretion for any reason.

(e) Any time after 30 days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a Notice of Resolution, IPCO may terminate this Agreement by providing written notice to the ISO that it is terminating this Agreement ("Termination Notice") effective immediately. IPCO may terminate this Agreement under the terms of this Section 2(e) at its sole discretion for any reason.

(f) In the event this Agreement is terminated by either or both of the Parties pursuant to its terms, this Agreement will become wholly void and of no further force and effect, without further action by either Party, and the liabilities and obligations of the Parties hereunder will terminate, and each Party shall be fully released and discharged from any liability or obligation under or resulting from this Agreement as of the date of the Termination Notice provided in Section 2(d) or 2(e), as applicable, notwithstanding the requirement for the ISO to submit the filing specified in Section 2(g). Notwithstanding the foregoing, the rights and obligations set forth in Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect as specified in Sections 5 and 6, and any milestone payment obligation pursuant to Section 4(c) that arose prior to the Termination Notice in accordance with Section 2(d) or 2(e) shall survive until satisfied or resolved in accordance with Section 11.

(g) The Parties acknowledge that the ISO is required to file a timely notice of termination with FERC. The Parties acknowledge and agree that the filing of the notice of termination by the ISO with FERC will be considered timely if the filing of the notice of termination is made after the preconditions for termination have been met, and the ISO files the notice of termination within ten (10) days after the Termination Notice has been provided by either the ISO in accordance with Section 2(d) or IPCO in accordance with Section 2(e). This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

3. Implementation Scope and Schedule.

(a) The Parties shall complete the Project as described in Exhibit A, subject to modification only as described in Section 4(e) below.

(b) The Parties shall undertake the activities described in Exhibit A with the objective of completing the Project and implementing the EIM no later than the Implementation Date, including all milestones listed under Exhibit A for the Implementation Date, subject to modification only as described in Section 3(c) below.

(c) Either Party may propose a change in Exhibit A or the Implementation Date to the other Party. If a Party proposes a change in Exhibit A or the Implementation Date, the Parties shall negotiate in good faith to attempt to reach agreement on the proposal and any necessary changes in Exhibit A and any other affected provision of this Agreement, provided that any change in Exhibit A, or any change to the Implementation Date, must be mutually agreed to by the Parties. The agreement of the Parties to a change in Exhibit A, or a change to the Implementation Date, shall be memorialized in a revision to Exhibit A, which will then be binding on the Parties and shall be posted on the internet web sites of the ISO and IPCO, without the need for execution of an amendment to this Agreement. Changes that require revision of any provision of this Agreement other than Exhibit A shall be reflected in an executed amendment to this Agreement and filed with FERC for acceptance.

(d) At least once per calendar month during the Term, the Parties' Designated Executives, or their designees, will meet telephonically or in person (at a mutually agreed to location) to discuss the status of the performance of the tasks necessary to achieve the milestones in Exhibit A and the continued appropriateness of Exhibit A to ensure that the Project can meet the Implementation Date. For purposes of this section, "Designated Executive" shall mean the individual identified in Section 8(g), or her or his designee or successor.

4. Implementation Charges, Invoicing and Milestone Payments.

(a) As itemized in Section 4(c) below, IPCO shall pay the ISO a fixed fee of $540,000 for costs incurred by the ISO to implement the Project ("Implementation Fee"), subject to completion of the milestones specified in Section 4(c) and subject to adjustment only as described in Section 4(b).

(b) The ISO will provide prompt written notice to IPCO when the sum of its actual costs through the date of such notice and its projected costs to accomplish the balance of the Project exceed the Implementation Fee. The Implementation Fee shall be subject to adjustment only by mutual agreement of the Parties if the Parties agree to a change in Exhibit A, or a change to the Implementation Date, in accordance with Section 3(c) and the Parties agree that an adjustment to the Implementation Fee is warranted in light of such change.

(c) Upon completion of the milestones identified in Exhibit A, the ISO shall invoice IPCO for the Implementation Fee as follows:

i. $90,000 upon the Effective Date as further described in Section 1 of this Agreement and Exhibit A as Milestone 1;

ii. $90,000 upon deployment into the ISO test environment of the full network model database that includes the topology of the IPCO system as further described in Exhibit A as Milestone 2;

iii. $90,000 upon ISO promotion of market network model including IPCO area to non-production system with IPCO connection and data exchange data in advance of market simulation as further described in Exhibit A as Milestone 3;

iv. $90,000 upon commencement of EIM market simulation as further described in Exhibit A as Milestone 4;

v. $90,000 upon start of parallel operations as further described in Exhibit A as Milestone 5; and

vi. $90,000 upon the Implementation Date as further described in Exhibit A as Milestone 6.

(d) Following the completion of each milestone identified in Section 4(c)(i) through (v), the ISO will deliver to IPCO an invoice which will show the amount due, together with reasonable documentation supporting the completion of the milestone being invoiced. IPCO shall pay the invoice no later than forty-five (45) days after the date of receipt. Any milestone payment past due will accrue interest, per annum, calculated in accordance with the methodology specified for interest in the FERC regulations at 18 C.F.R. § 35.19a(a)(2)(iii) (the "FERC Methodology").

(e) If a milestone has not been completed as described in Section 4(c)(i), (ii), (iii), (iv), or (v) and in Exhibit A, as Exhibit A may have been modified in accordance with Section 3(c), the Parties shall negotiate in good faith an agreed upon change to the Project Delivery Dates (as defined in Exhibit A) consistent with Section 3(c) such that the timing of milestone payments in Section 4(c) can be adjusted to correspond to the updated Exhibit A.

(f) If IPCO disputes any portion of any amount specified in an invoice delivered by the ISO in accordance with Section 4(c), IPCO shall pay its total amount of the invoice when due, and identify the disputed amount and state that the disputed amount is being paid under protest. Any disputed amount shall be resolved pursuant to the provisions of Section 11. If it is determined pursuant to Section 11 that an overpayment or underpayment has been made by IPCO or any amount on an invoice is incorrect, then (i) in the case of any overpayment, the ISO shall promptly return the amount of the overpayment (or credit the amount of the overpayment on the next invoice) to IPCO; and (ii) in the case of an underpayment, IPCO shall promptly pay the amount of the underpayment to the ISO. Any overpayment or underpayment shall include interest for the period from the date of overpayment, underpayment, or incorrect allocation, until such amount has been paid or credited against a future invoice calculated in the manner prescribed for calculating interest in Section 4(d).

(g) All costs necessary to implement the Project not provided for in this Agreement shall be borne separately by each Party, which in the case of the ISO will be recovered through rates as may be authorized by its regulatory authorities.

(h) All milestone payments required to be made under the terms of this Agreement shall be made to the account or accounts designated by the Party which the milestone payment is owed, by wire transfer (in immediately available funds in the lawful currency of the United States).

5. Confidentiality.

(a) All written or oral information received from the other Party in connection with this Agreement (but not this Agreement after it is filed with FERC) necessary to complete the Project and marked or otherwise identified at the time of communication by such Party as containing information that Party considers commercially sensitive or confidential shall constitute "Confidential Information" subject to the terms and conditions herein.

(b) If IPCO publicly releases IPCO's Confidential Information in connection with a public process or a regulatory filing, or if the ISO publicly releases the ISO's Confidential Information in connection with a public process or a regulatory filing, then the information released shall no longer constitute Confidential Information; provided, however, that Confidential Information disclosed under seal (or in such other manner as to be treated confidentially) in connection with a regulatory filing shall retain its status as Confidential Information under this Agreement. In addition, Confidential Information does not include information that (i) is or becomes generally available to the public other than as a result of disclosure by either Party, its officers, directors, employees, agents, or representatives; (ii) is or becomes available to such Party on a non-confidential basis from other sources or their agents or representatives when such sources are not known by such Party to be prohibited from making the disclosure; (iii) is already known to such Party or has been independently acquired or developed by such Party without violating any of such Party's obligations under this Section 5; (iv) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, with regard to information for discussion at any stakeholder meetings or during the stakeholder process or with any regulatory authority; or (v) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, to allow for such disclosure and designation as non-confidential or public information on a case-by-case basis in accordance with Section 10 of this Agreement.

(c) The Confidential Information will be kept confidential by each Party and each Party agrees to protect the Confidential Information using the same degree of care, but no less than a reasonable degree of care, as a Party uses to protect its own confidential information of a like nature. Notwithstanding the preceding sentence, a Party may disclose the Confidential Information or portions thereof to those of such Party's officers, employees, partners, representatives, attorneys, contractors, advisors, or agents who need to know such information for the purpose of analyzing or performing an obligation related to the Project. Notwithstanding the foregoing, a Party is not authorized to disclose such Confidential Information to any officers, employees, partners, representatives, attorneys, contractors, advisors, or agents without (i) informing such officer, employee, partner, representative, attorney, contractor, advisor, or agent of the confidential nature of the Confidential Information and (ii) ensuring that such officer, employee, partner, representative, attorney, contractor, advisor, or agent is subject to confidentiality duties or obligations to the applicable Party that are no less restrictive than the terms and conditions of this Agreement. Each Party agrees to be responsible for any breach of this Section 5 by such Party or a Party's officers, employees, partners, representatives, attorneys, contractors, advisors or agents, subject to the limitations set forth in Section 6 below.

(d) In the event that a Party is required by a court of competent jurisdiction or regulatory authority (by law, rule, regulation, order, deposition, interrogatory, request for documents, data request issued by a regulatory authority, subpoena, civil investigative demand or similar request or process) to disclose any of the Confidential Information, such Party shall (to the extent legally permitted) provide the other Party with prompt written notice of such requirement so that the other Party may seek a protective order or other appropriate remedy and/or waive compliance with the terms of this Section 5. In the event that such protective order or other remedy is not obtained, the disclosing Party hereby waives compliance with the provisions hereof with respect to such Confidential Information. In such event, the Party compelled to disclose shall (i) furnish only that portion of the Confidential Information which, in accordance with the advice of its own counsel (which may include internal counsel), is legally required to be furnished, and (ii) exercise reasonable efforts to obtain assurances that confidential treatment will be accorded the Confidential Information so furnished.

(e) Notwithstanding the foregoing, the Parties acknowledge that they are required by law or regulation to report certain information that could embody Confidential Information from time to time, and may do so from time to time without providing prior notice to the other Party. Such reports may include models, filings, and reports of costs, general rate case filings, cost adjustment mechanisms, FERC-required reporting, investigations, annual state reports that include resources and loads, integrated resource planning reports, reports to entities such as FERC, the North American Electric Reliability Council ("NERC"), Western Electricity Coordinating Council ("WECC"), or similar or successor organizations, or similar or successor forms, filings, or reports, the specific names of which may vary by jurisdiction, along with supporting documentation. Additionally, in regulatory proceedings or investigations in all state and federal jurisdictions in which they may do business, the Parties will from time to time be required to produce Confidential Information, and may do so without prior notice using its business judgment in compliance with all of the foregoing and including the appropriate level of confidentiality for such disclosures in the normal course of business.

(f) Each Party is entitled to seek equitable relief, by injunction or otherwise, to enforce its rights under this Section 5 to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision, subject to the limitations set forth in Section 6 below.

(g) Upon written request by a Party, the other Party shall promptly return to the requesting Party or destroy all Confidential Information it received, including all copies of its analyses, compilations, studies or other documents prepared by or for it, that contain the Confidential Information in a manner that would allow its extraction or that would allow the identification of the requesting Party as the source of the Confidential Information or inputs to the analysis. Notwithstanding the foregoing, neither Party shall be required to destroy or alter any computer archival and backup tapes or archival and backup files (collectively, "Computer Tapes"), provided that such Computer Tapes shall be kept confidential in accordance with the terms of this Agreement.

(h) Nothing in this Agreement shall be deemed to restrict either Party from engaging with third parties with respect to any matter and for any reason, specifically including the EIM, provided Confidential Information is treated in accordance with this Section 5.

(i) This Section 5, Confidentiality, applies for two years (24 months) after the Termination Date or the date of any expiration or termination of this Agreement.

6. Limitation of Liability; Indemnity.

(a) The Parties acknowledge and agree that, except as otherwise specified in Section 4(f) of this Agreement, neither Party shall be liable to the other Party for any claim, loss, cost, liability, damage or expense, including any direct damage or any special, indirect, exemplary, punitive, incidental or consequential loss or damage (including any loss of revenue, income, profits or investment opportunities or claims of third party customers), arising out of or directly or indirectly related to such other Party's decision to enter into this Agreement, such other Party's performance under this Agreement, or any other decision by such Party with respect to the Project.

(b) Each Party shall indemnify, defend and hold harmless each of the other Party and its officers, directors, employees, agents, contractors and sub-contractors, from and against all third-party claims, judgments, losses, liabilities, costs, expenses (including reasonable attorneys' fees) and damages for personal injury, death or property damage, to the extent caused by the negligence, willful misconduct, or breach of this Agreement of the indemnifying Party, its officers, directors, agents, employees, contractors or sub-contractors related to this Agreement; provided, that this indemnification shall be only to the extent such personal injury, death or property damage is not attributable to the negligence or willful misconduct related to this Agreement or breach of this Agreement of the Party seeking indemnification, its officers, directors, agents, employees, contractors or sub-contractors. The indemnified Party shall give the other Party prompt notice of any such claim. The indemnifying Party, in consultation with the indemnified Party, shall have the right to choose competent counsel, control the conduct of any litigation or other proceeding, and settle any claim, provided that any such settlement shall not impose costs upon the indemnified Party. The indemnified Party shall provide all documents and assistance reasonably requested by the indemnifying Party.

(c) The rights and obligations under this Section 6 shall survive the Termination Date and any expiration or termination of this Agreement.

7. Representation and Warranties.

(a) Representations and Warranties of IPCO. IPCO represents and warrants to the ISO as of the Effective Date as follows:

(1) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(2) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(3) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(6) All material governmental authorizations in connection with the due execution and delivery of this Agreement, have been duly obtained or made prior to the date hereof and are in full force and effect.

(b) Representations and Warranties of the ISO. ISO represents and warrants to IPCO as of the Effective Date as follows:

(1) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(2) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(3) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, regulatory authority, or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(6) All material governmental authorizations in connection with the due execution and delivery of, and performance by it of its obligations under this Agreement, have been duly obtained or made prior to the date hereof and are in full force and effect.

8. General Provisions.

(a) This Agreement, including Exhibit A to this Agreement, constitutes the entire agreement between the Parties, and supersedes any prior written or oral agreements or understandings between the Parties, relating to the subject matter of this Agreement; provided, that nothing in this Agreement shall limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of each of the Parties as provided by any other agreement between the Parties, or by any statute or any other law or applicable court or regulatory decision by which such Party is bound.

(b) This Agreement may not be amended except in writing hereafter signed by both of the Parties; provided, however, the Parties may mutually agree to changes in Exhibit A in accordance with Section 4(e).

(c) Any waiver by a Party to this Agreement of any provision or condition of this Agreement must be in writing signed by the Party to be bound by such waiver, shall be effective only to the extent specifically set forth in such writing and shall not limit or affect any rights with respect to any other or future circumstance.

(d) This Agreement is for the sole and exclusive benefit of the Parties and shall not create a contractual relationship with, or cause of action in favor of, any third party.

(e) Neither Party shall have the right to voluntarily assign its interest in this Agreement, including its rights, duties, and obligations hereunder, without the prior written consent of the other Party, which consent may be withheld by the other Party in its sole and absolute discretion. Any assignment made in violation of the terms of this Section 8(e) shall be null and void and shall have no force and effect.

(f) In the event that any provision of this Agreement is determined to be invalid or unenforceable for any reason, in whole or part, the remaining provisions of this Agreement shall be unaffected thereby and shall remain in full force and effect to the fullest extent permitted by law, and such invalid or unenforceable provision shall be replaced by the Parties with a provision that is valid and enforceable and that comes closest to expressing the Parties' intention with respect to such invalid or unenforceable provision.

(g) Whenever this Agreement requires or provides that (i) a notice be given by a Party to the other Party or (ii) a Party's action requires the approval or consent of the other Party, such notice, consent or approval shall be given in writing and shall be given by personal delivery, by recognized overnight courier service, email or by certified mail (return receipt requested), postage prepaid, to the recipient thereof at the address given for such Party as set forth below, or to such other address as may be designated by notice given by any Party to the other Party in accordance with the provisions of this Section 8(g):

If to IPCO:

Idaho Power Company
1221 W. Idaho Street
Boise, Idaho 83702
Attention: Tessia Park, Vice President of Power Supply
E-mail: tpark@idahopower.com

If to the ISO:

California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Attention: Petar Ristanovic, Vice President, Technology
E-mail: PRistanovic@caiso.com

Each notice, consent or approval shall be conclusively deemed to have been given (i) on the day of the actual delivery thereof, if given by personal delivery, email sent by 5:00 p.m., or overnight delivery, or (ii) date of delivery shown on the receipt, if given by certified mail (return receipt requested). It is the responsibility of each Party to provide, in accordance with this Section, notice to the other Party of any necessary change in the contact or address information herein.

(h) This Agreement may be executed in one or more counterparts (including by facsimile or a scanned image), each of which when so executed shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

(i) Nothing contained in this Agreement shall be construed as creating a corporation, company, partnership, association, joint venture or other entity with the other Party, nor shall anything contained in this Agreement be construed as creating or requiring any fiduciary relationship between the Parties. No Party shall be responsible hereunder for the acts or omissions of the other Party.

(j) The decision to execute an EIM service agreement and participate in the EIM remains within the sole discretion of IPCO and the decision whether to continue to offer EIM services (subject to Sections 1(c) and 2) remains within the sole discretion of the ISO.

(k) Nothing in this Agreement shall preclude a Party from exercising any rights or taking any action (or having its affiliates take any action) with respect to any other project.

(l) Unless otherwise expressly provided, for purposes of this Agreement, the following rules of interpretation shall apply: (i) any reference in this Agreement to gender includes all genders, and the meaning of defined terms applies to both the singular and the plural of those terms; (ii) the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this Agreement; (iii) all references in this Agreement to any "Section" are to the corresponding Section of this Agreement unless otherwise specified; (iv) words such as "herein," "hereinafter," "hereof," and "hereunder" refer to this Agreement (including Exhibit A to this Agreement) as a whole and not merely to a subdivision in which such words appear, unless the context otherwise requires; (v) the word "including" or any variation thereof means "including, without limitation" and does not limit any general statement that it follows to the specific or similar items or matters immediately following it; and (vi) the Parties have participated jointly in the negotiation and drafting of this Agreement and, in the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as jointly drafted by the Parties and no presumption or burden of proof favoring or disfavoring any Party will exist or arise by virtue of the authorship of any provision of this Agreement.

(m) The above-stated recitals are incorporated into and made a part of this Agreement by this reference to the same extent as if these recitals were set forth in full at this point.

9. <u>Venue</u>. Venue for any action hereunder shall be FERC, where subject to its jurisdiction, or otherwise any state or federal court with jurisdiction.

10. <u>Communication.</u> The Parties shall develop a communication protocol for the dissemination of material information associated with the Project, which shall be approved by IPCO and the ISO. Pursuant to the communication protocol, the individual

identified in Section 8(g), or their designee or successor, shall provide reasonable advance notice to the other Party of planned press releases, public statements, and meetings with the public or governmental authorities in which material information concerning the Project or IPCO's involvement will be shared. The Parties shall mutually consult with each other as provided in the communication protocol prior to making such public statements or disclosures; provided that nothing herein shall prevent, limit, or delay either Party from making any disclosure required by applicable law or regulation, subject to the provisions of Section 5 hereof. In the event either Party engages in material unplanned communications about the Project that otherwise should have been subject to this Section and the communication protocol, such Party shall provide notice to the other Party as promptly as possible of the nature and content of such communication.

11. Dispute Resolution. Unless otherwise provided herein, each of the provisions of this Agreement shall be enforceable independently of any other provision of this Agreement and independent of any other claim or cause of action. In the event of any dispute arising under this Agreement, the Parties shall, to the extent practicable, first attempt to resolve the matter through direct good faith negotiation between the Parties, including a full opportunity for escalation to executive management within the Parties' respective organizations. If the Parties are unable to resolve the issue within thirty (30) days after such escalation of the dispute, then for matters subject to FERC jurisdiction either Party shall have the right to file a complaint under Section 206 of the Federal Power Act. For all other matters, then:

(a) To the fullest extent permitted by law, each of the Parties hereto waives any right it may have to a trial by jury in respect of litigation directly or indirectly arising out of, under or in connection with this Agreement. Each Party further waives any right to consolidate, or to request the consolidation of, any action in which a jury trial has been waived with any other action in which a jury trial cannot be or has not been waived.

(b) If a waiver of jury trial is deemed by any court of competent jurisdiction to not be enforceable for any reason, then to the fullest extent permitted by law, each of the Parties hereto agrees to attempt to settle amicably through non-binding arbitration. Notwithstanding the foregoing, either Party may seek provisional legal remedies if, in such Party's judgment, such action is necessary to avoid irreparable damage or preserve the status quo.

12. Third Party Agreements. The Parties may engage in discussions with third parties, either jointly or unilaterally, to facilitate the Project. Each Party may adopt or modify tariffs or enter into or modify binding agreements between such Party and third parties to implement the approved terms and conditions of the Project or EIM as necessary and appropriate.

13. Compliance. Each Party shall comply with all federal, state, local or municipal governmental authority; any governmental, quasi-governmental, regulatory or

administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC, WECC; or any court or governmental tribunal; in each case, having jurisdiction over either Party in connection with the execution, delivery and performance of its obligations under this Agreement. This Agreement is not intended to modify, change or otherwise amend the Parties' current functional responsibilities associated with compliance with WECC and NERC Reliability Standards; provided, however, the Parties may enter into separate mutually agreed to arrangements to clarify roles and responsibilities associated with compliance with WECC and NERC Reliability Standards in respect of this Agreement.

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Implementation Agreement as of the date first above written.

IDAHO POWER COMPANY

By: Lisa Grow

Name: Lisa Grow
Title: Sr. Vice President, Operations

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

By: Петар Ристановић

Name: Petar Ristanovic
Title: Vice President, Technology

EXHIBIT A: PROJECT SCOPE AND SCHEDULE

The Project consists of the activities and delivery dates identified in this Exhibit A, implemented in accordance with the Agreement. The Parties have included a schedule for the Implementation Date to coordinate their efforts required for completion of the Project on a milestone track.

The Parties understand that input received from stakeholders during the course of implementing the Project, conditions imposed or questions raised in the regulatory approval process, and the activities of the Parties in implementing the Project may cause the Parties to determine that changes in the Project are necessary or desirable. Accordingly, this Exhibit A may be modified in accordance with Section 3(c) of the Agreement.

Each Party is responsible for performing a variety of tasks necessary to achieve the milestones on the scheduled dates specified in the table below ("Project Delivery Dates") and shall plan accordingly. The Parties shall communicate and coordinate as provided in the Agreement to support the planning and execution to complete the Project.

Project Scope and Milestones	**Project Delivery Dates supporting April 2018**
Detailed Project Management Plan – The Parties will develop and initiate a final project management plan that describes specific project tasks each Party must perform, delivery dates, project team members, meeting requirements, and a process for approving changes to support completion of the Project.	June 2016
• **Milestone 1** – This milestone is completed when the Agreement has been made effective in accordance with Section 1 of the Agreement.	July 2016
Full Network Model Expansion – Full Network Model expansion for IPCO and EMS/SCADA, including, proof of concept of export/import of EMS data; complete model into the ISO test environment; complete validation for all SCADA points from IPCO; testing of the new market model; and validation of the Outage and State Estimator applications.	August 2017

• **Milestone 2** - This milestone is completed upon modeling IPCO into the ISO Full Network Model through the EMS which will be deployed into a non-production test environment using the ISO's network and resource modeling process.	August 2017
System Implementation and Connectivity Testing – System requirements and software design, the execution of necessary software vendor contracts, development of Market network model including IPCO, allow IPCO to connect to a non-production test system.	September 2017
• **Milestone 3** - ISO to promote market network model including IPCO area to non-production system, and allow IPCO to connect and exchange data in advance of Market Simulation.	September 2017
Construction, Testing and Training in Preparation for Market Simulation - This task includes IT infrastructure upgrades, security testing, training, Day-in-life simulation, and functional testing.	October 2017
• **Milestone 4a** – Start of Connectivity to ISO Testing, Interface testing with minimum data requirements and functional integration testing. ISO will make the test environment available for PGE connectivity testing prior to the delivery date assuming PGE has provided all requisite data and non-production system availability does not conflict with ISO production system Spring Release schedule.	September, 2017
• **Milestone 4b –Begin 'Day in the Life' scenario testing**	October 2017
• **Milestone 4c – Begin Structured Market simulation**	November 2017
Activate Parallel Operations - Beginning August 1, 2017, the ISO will activate a parallel operation environment to practice production grade systems integration as well as market processes and operating procedures in anticipation of the impending IPCO activation as an EIM Entity and to confirm compliance with the EIM readiness criteria set forth in the ISO tariff.	January 2018
• **Milestone 5** – Start of parallel operations	February 1, 2018

System Deployment and Go Live – Implementing the Project and going live will include resource registration, operating procedures and updates, execution of service agreements, completion of the IPCO tariff process, applicable board approvals, the filing and acceptance of service agreements and tariff changes with FERC, and completion and filing of a readiness criteria certification in accordance with the ISO tariff.	March 2018
• **Milestone 6 –** This milestone is complete upon the first production IPCO energy imbalance market trade date.	April 1, 2018

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-19

IDAHO POWER COMPANY

ANDERSON, DI
TESTIMONY

EXHIBIT NO. 4

Idaho Power Company
Energy Imbalance Market Analysis

February 2016

Energy+Environmental Economics

Idaho Power Company Energy Imbalance Market Analysis

February 2016

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Prepared For:
Idaho Power Company

Prepared By:
Jack Moore, Sheridan Grant, Sharad Bharadwaj, and Brian Conlon
Energy and Environmental Economics, Inc. (E3)

Tao Guo, Guangjuan Liu, and Yannick Degeilh
Energy Exemplar

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Acronyms

APS	Arizona Public Service Company
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business-as-usual
CAISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
IPC	Idaho Power Company
LMP	Locational Marginal Price
NVE	NV Energy
NWPP	Northwest Power Pool
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric Company
PNNL	Pacific Northwest National Laboratory
PSE	Puget Sound Energy
WECC	Western Electric Coordinating Council

Executive Summary

Over the past year, in an effort to increase operational efficiency and create cost savings for IPC customers, Idaho Power Company (IPC) has been exploring participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO). As part of its assessment of opportunities for regional coordination, IPC engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of IPC's participation in the Western EIM. This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate IPC's benefits resulting from participation in the EIM by comparing IPC's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which IPC does not participate in the EIM. To focus on the incremental impact of IPC participation, the BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. These BAAs are listed in the table below.

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K. Anderson, IPC
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Table 1: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $4.5 million in annual sub-hourly dispatch cost savings for IPC. Under an alternative scenario with higher renewable buildout in the region, EIM participation created $5.1 million in total sub-hourly dispatch cost savings to IPC. Savings due to reduced flexibility reserves (from the diversity provided by the EIM) were not estimated in this study, but would provide savings in addition to the figures stated above. For example, in a previous study E3 estimated that PGE would receive $0.8 million in savings due to reduced flexibility reserves from joining the EIM.

Table 2. Annual Savings to IPC from Participation in EIM (2015$ million)

Scenario	EIM Savings to IPC
Base Scenario	$4.5
No APS or PGE	$4.2
Early Coal Retirement	$4.1
High RPS Case	$5.1

Overall, this study estimates that participation in the EIM would produce modest positive savings for IPC, and that savings from participation would be larger in the presence of larger renewable resource buildout. In addition to savings to IPC, we also estimate that IPC participation in the EIM would produce over $2 million in incremental savings for the current EIM participants.

Base Scenario savings to IPC are positive and modest due to a combination of factors. Monthly 2020 gas prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region; the average price for IPC area generators was $3.27/MMBTU for 2020 (in 2015 dollars). These relatively low gas prices moderated the value of EIM flexibility to IPC. Additionally, IPC's generator portfolio modeled for 2020 includes flexible hydro resources that can respond quickly to changes in sub-hourly needs, making IPC's flexibility needs lower than those of a utility without much flexible generation.

The model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030,[1] in addition to customer-side renewable resources such as rooftop solar. These developments may provide increasing opportunities for EIM participants to purchase energy from California in real time at a low cost.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to IPC for evaluation of participation in the EIM. The study does not quantify potential benefits from improved dispatch in the hour-

[1] See California Legislature, 2015: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major outage. The study does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units. The study does not compare the savings to the incremental costs of joining an EIM. Finally, the study does not estimate savings to IPC or other EIM participants arising from flexibility reserve reductions due to load and variable resource diversity across the footprint.

EIM market discussion

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[2] The EIM can create real-time dispatch cost savings for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits; (2) bringing this optimized dispatch down to a 5-minute interval level; and (3) incorporating optimized real-time unit commitment of quick-start generation.

Additionally, by allowing BAs to pool load and generation resources on a sub-hourly basis, the EIM can enable participants to reduce the number of units they individually need to commit to provide flexibility reserves within the hour. In

[2] For more information regarding the EIM, see https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

December 2011, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[3] Each generator chosen to resolve a constraint is compensated at the marginal generator unit's shadow price, which reflects the opportunity cost for production. The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted downward to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint. While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

[3] See CAISO, 2014: Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. The CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability. https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

Modeling Approach

This study analyzes the impact of IPC participation in the EIM using the PLEXOS production cost modeling software to simulate sub-hourly operations in the Western Interconnection for the year 2020. Energy Exemplar provided technical support to this study and implemented the sub-hourly production simulation runs in PLEXOS. Savings were identified as *sub-hourly dispatch benefits*, which realize the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between IPC and the current EIM footprint.

As a starting point, this study used the PLEXOS database developed by Pacific Northwest National Laboratory (PNNL) for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[4] and revised as part of the NWPP Phase 1 EIM study from 2013.[5] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis.

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[6], which updated the database

[4] See WECC, 2013, Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling. Available at http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf.

[5] See Samaan, NA, et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.

[6] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf

from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

E3 quantified the sub-hourly dispatch savings from IPC's participation in the EIM by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (which include IPC) equal to the scheduled levels from the HA simulation but allowing EIM participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM cases (starting from the same HA simulation as the BAU case) that each allow IPC to transact power within the hour with other EIM participants. The increased flexibility in the EIM cases produces a reduction in real time production costs for the region, which represents the total societal EIM-wide savings as a result of IPC participation. Benefits are then divided between IPC and the current EIM participants based on the change in their generation cost and their net purchases and sales in real time through the EIM.

Scenario Description

The Base Scenario of this analysis uses gas hub prices from OTC Global Holding Natural Gas Forwards & Futures, which are $3.27/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets and projected renewable buildout for 2020. This includes a 33% RPS for California, a 15% renewable penetration for IPC, and an average 15% renewable share for other Northwest region BAAs not participating in the EIM. We also analyzed alternative scenarios which model a higher renewable penetration in the west: a 40% RPS for California, a 20% renewable share for IPC, and a 20% renewable share for the other Northwest region BAAs not participating in the EIM.

Summary of results

The base scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for IPC of $4.5 million in the EIM. IPC participation also provides incremental savings to other EIM participants. These savings are largely robust to the additional retirement of regional coal generation or the absence of planned APS and PGE participation in the EIM, with savings to IPC remaining above $4 million in all scenarios. A higher RPS would result in larger benefits for IPC participation, estimated at $5.1 million per year.

1 Introduction

Idaho Power Company (IPC) engaged E3 to analyze the potential economic benefits of IPC's participation in the Western EIM. This study seeks to identify the savings potential of IPC's participation in the Western EIM and includes a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include early retirement of certain coal plants in the West, altered participation of other BAs in the EIM, and the penetration level of intermittent renewable resources.

1.1 Context for Study

Utilities throughout the WECC have been increasingly interested in exploring a wider range of opportunities for improved coordination between neighboring BAAs. These have included the

+ Western EIM (previously referred to as the CAISO EIM), which allows for a voluntary 5-minute market. The EIM began operating in November 2014 with PacifiCorp and CAISO as initial members. NV Energy began participating in 2015. Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016. Portland General Electric Company has announced participation to begin in 2017.

+ Northwest Power Pool investigation of a SCED for real time sub-hourly transactions, similar to an EIM, as well as other opportunities to promote more active and liquid 15-minute trading in the region.

A number of studies have highlighted the benefits of improved regional coordination, particularly in a context of higher renewable and intermittent resources on the system. These types of resources incur higher variability and forecast error for each BA, and without regional coordination each individual BA would be forced to maintain higher flexibility to combat this increased intermittency. IPC engaged E3 to conduct a comparative study of the impact and potential savings from IPC participation in the EIM. E3, working with Energy Exemplar, analyzed IPC participation using a three-stage zonal production simulation model of the Western Interconnection in PLEXOS. This study was done in close coordination with Energy Exemplar and IPC staff.

1.2 Structure of this Report

The remainder of this report is comprised of the following sections:

+ **Section 2** describes the key study assumptions and methods used in this analysis.
+ **Section 3** presents the results of our analysis of IPC participation in the Western EIM.

2 Study Assumptions and Approach

2.1 Overview of Approach

The Western EIM allows participating Western BAs to voluntarily participate in CAISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances, as well as committing quick-start generation every 15 minutes using security constrained unit commitment (SCUC). An important distinction between the EIM and a Regional Transmission Organization is that in the EIM each participating BA remains responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices for unit commitment and scheduling in advance of real-time.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in Section 2.4 below.

This study is designed to measure one principal type of benefits: **sub-hourly dispatch benefits**. Today, each BA in the Western Interconnection outside of the EIM typically dispatches its own internal generating resources to meet imbalances within the hour, while holding real-time exchange with neighboring BAs fixed to the hour-ahead schedule. The EIM can net energy imbalance across participating BAs and economically dispatch generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. IPC's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without IPC.

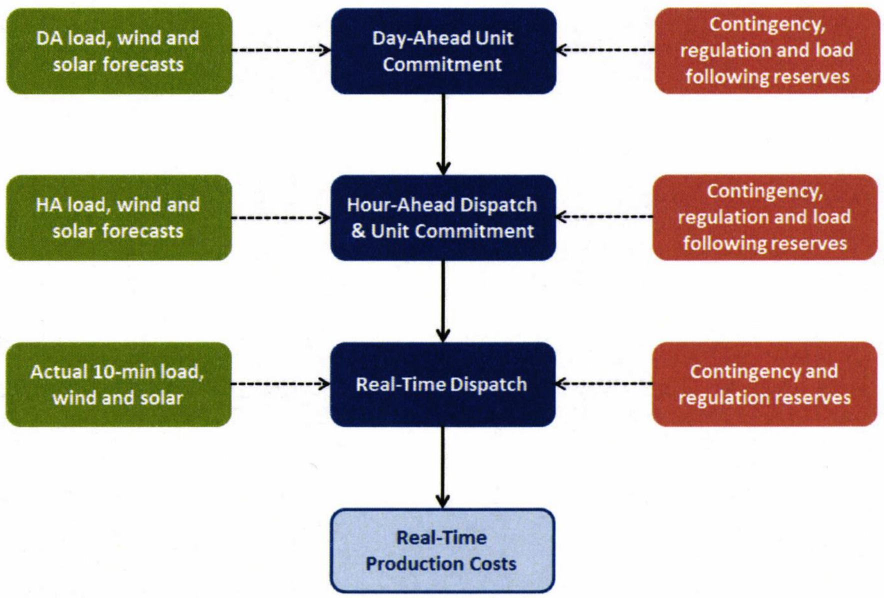
This study does not quantify savings associated with flexibility reserve reductions. Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; thus, participation in the EIM does not reduce the physical generation capacity that a BA needs. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

2.2 Sub-hourly Dispatch Benefits Methodology

2.2.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch as well as hourly interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances. The DA, HA, and real-time sequential simulation approach allows PLEXOS to differentiate

Exhibit No. 4
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operations for BAs participating or not participating in the EIM. When a BA is not participating in a real-time market, then: (a) interchange is unconstrained during the DA and HA simulations; and (b) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation.

In contrast, during the real-time simulation, BAs participating in the EIM can re-dispatch generation and exchange power with the rest of the EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.3.2 below.

While the Western EIM operates down to a 5-minute level in practice, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across the California-Oregon Intertie (COI) and BPA network. In the final stage, the RT simulation for this study is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM benefits results that we expect may be conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM could provide. Overall, however, we expect the 10-minute time step to capture the majority of the real-time dispatch efficiency savings.

2.2.2 BAU SIMULATION

In the BAU case, IPC does not participate in the EIM, and must resolve its real-time imbalances with internal generation only. IPC's real-time import and exports are held fixed to the hour-ahead schedule.

Real-time sub-hourly interchanges are simulated among BAAs that are modeled as existing participants in the Western EIM, reflecting the operational efficiencies realized by the EIM before including IPC participation. In other words, the Western EIM is assumed to be fully operating without IPC's participation. As a result, savings and efficiencies associated with sub hourly dispatch for each alternative are included in the system cost. These costs serve as the "control" case to compare against the cases with IPC participation.

The BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. The BAAs modeled as current participants in the EIM for the BAU Case are listed in the table below.

Table 3: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

2.2.3 WESTERN EIM SIMULATIONS

The EIM cases simulate real-time dispatch with IPC participating in the Western EIM. In each of these cases, intra-hour interchange between IPC and existing EIM participants is allowed up to the assumed transmission transfer limits.

2.3 Key Modeling Assumptions

Three key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; and (3) hurdle rates.

2.3.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, or standardized energy products which include On-Peak, Off-Peak, and Flat energy blocks. These products require long lead times between scheduling the transaction and actual dispatch.[7] Within the hour, each BA resolves imbalances by dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

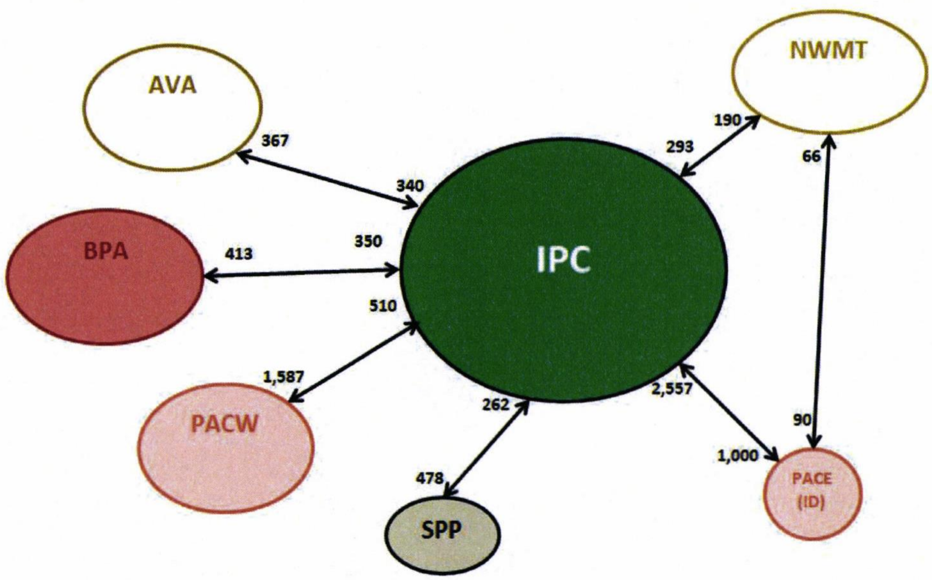
2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real time between participants. This study's transmission topology was built on that of E3's PGE EIM study from 2015 and was updated with the help of IPC transmission experts.

IPC's BAA has direct connections with six other BAAs: AVA, BPA, PACW, PACE, NVE, and NWMT. IPC has significant transfer capability with both PACE and PACW. In the BAU Scenario (without IPC participating) PACE and PACW were assumed to have only 200 MW of east to west dynamic capability between them available for incremental EIM transfers not scheduled in the hour ahead. A zonal depiction of IPC's transmission interconnections is shown in Figure 2.

[7] The Western EIM and AESO are the exceptions.

Figure 2. Real-time Transfer Capabilities with IPC



2.3.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;
+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, in some cases resulting in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and

+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as DA block trading products, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", which are applied as $/MWh price adders to energy transfers on interfaces between BAAs. Hurdle rates are applied in the DA and HA cases to inhibit power flow over transmission paths that cross BAA boundaries, to represent these inherent inefficiencies and reduce economic energy exchange between BAAs.

The EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates in real time. Intra-hour exchanges among participants in the EIM are allowed during the real-time simulation cases. The simulation does not allow incremental intra-hour exchanges (beyond the HA schedule) between BAAs that are non-participants in an EIM. The absence of hurdle rates in real time in this analysis is consistent with the FERC-approved CAISO tariff amendment associated with the EIM.

In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants. We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we expect that BAs may adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

In addition to the hurdle rates described above, charges for CO_2 import fees related to California Assembly Bill (AB) 32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

For interties among the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM cases.

2.3.4 FLEXIBILITY RESERVE REQUIREMENTS

By pooling load and resource variability across space and time, total variability of the combined net load for participants in the EIM footprint can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by:

- requiring fewer thermal generators to be inefficiently committed and operated, and
- decreasing flex reserve requirements placed on hydro resources, enabling them to more efficiently generate energy at times most valuable to their systems.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participation in the EIM.

While there is currently no uniformly defined requirement for BAs to carry flexibility reserves, all BAs must maintain Area Control Error (ACE) within acceptable NERC-defined limits, which necessitates that BAs hold reserves on generators to respond to within-hour changes in load and variable resource output. These reserve needs will grow under higher renewable penetration scenarios.

Additionally, in December 2014, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[8] Generators that are chosen to resolve a constraint are compensated at the generation shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint

[8] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. See also CAISO , 2015, Flexible Ramping Products Revised Draft Final Proposal. Available at: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

requirements for the CAISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

In the simulations run for this study, flexibility reserves were **not** adjusted to reflect net load diversity in any scenario (BAU and EIM case). This means that the benefits found in this study do not include benefits arising from reductions in flexibility reserves upon joining the EIM. In a previous study, E3 estimated that PGE would receive $0.8 million in *additional* savings due to reduced flexibility reserves from joining the Western EIM.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[9], which updated the database from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

[9] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

This study for IPC further refined the study database used in the PGE EIM analysis. These refinements are described below in more detail. Utilizing this database allowed this study to reflect the best available information compiled to represent BAAs in the Northwest.

This study made the following key updates to the case:

+ **Topology updates**. The 2015 PGE EIM study was used as a starting point for topology data. Major changes include removing a transmission link from SCL to IPC zones because it is a link to SCL-owned hydro generator at Lucky Peak, not the SCL balancing authority area. Additionally, E3 updated the line rating for the link between Northwestern and IPC to reflect the latest WECC path ratings.
+ **Gas prices**. Monthly 2020 hub prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region.[10] As in the PGE EIM study, these data were translated from hub prices to BA- or plant-specific burner tip prices using the mapping of pipelines, variable transport fees, and other adjustments outlined in the NWPP Phase 1 assessment.
+ **Hydro optimization window**. In practice, IPC plans its dispatch of flexible hydro units up to a week in advance to optimize the value of its reservoirs. This flexibility of hydro generation is prominent in the Northwest. Yet modeling hydro as such in PLEXOS runs the risk of unrealistically optimizing hydro dispatch with perfect foresight over a very long time horizon, without reflection of forecast error in identifying when the hydro will most be needed. Therefore, to balance dispatchable hydro units and maintain flexibility, while preventing

[10] Obtained from SNL Financial LC on October 15, 2015

perfect foresight, dispatchable hydro units for this study are optimized with a 24-hour optimization window. In this study, hydro modeling is handled through a series of interactions between simulation stages: monthly hydro energy budgets, which are database inputs, are allocated to each day using PLEXOS's monthly MT simulation based on anticipated load, wind, and solar across the month. Then, the DA and HA simulation stage first optimizes the hydro for each hour based on a DA and HA forecast of hourly load, wind and solar, constrained by the daily generation budget. The RT simulation is permitted to update the hourly hydro schedule across the day to respond to real-time needs within each of the six 10-minute sub-hourly intervals each hour but must maintain the same daily hydro energy total.

+ **Renewable generation updates in California**. Consistent with the PGE EIM study, this analysis has also updated the CAISO renewable resource mix to reflect a higher expected share of solar PV in the 2020 renewable resource portfolio and lower share of wind resources, based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the CAISO, which was not reflected in the original TEPPC model.

+ **Generation updates in the Northwest**. In order to collect and verify generator data for the PGE EIM study, PGE arranged discussions with experts from several northwestern BAs, including IPC. The data collected from these sessions were integrated in the PGE study database. For this study, IPC reviewed and largely maintained this data, making minor changes to its generator fleet. In the early coal retirement scenario the following units were retired as well: Valmy1, Valmy2, RdGrdnr4, Navajo1, SanJuan2, SanJuan3.

2.4.2 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 4 scenarios with different assumptions regarding the current participants in the EIM, the retirement dates of coal plants throughout the west, and the buildout of renewable resources by 2020. The scenarios were developed based on input from IPC staff to highlight changes that IPC believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating sub-hourly benefits.

Because IPC is interested in the benefits of joining the Western EIM[11], this study defines a base scenario that represents a plausible trajectory for the West's operating environment in which IPC joins the Western EIM. This base scenario is subjected to three sensitivities: (1) APS and PGE are assumed to not have joined the EIM by 2020 as planned; (2) Certain coal plants in the West are modeled to retire earlier than planned in the base case; and (3) significant renewable generation is added in California and throughout the West.

[11] In all scenarios but one, CAISO, PAC, NVE, PSE, APS, and PGE are assumed to be already participating in the Western EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study. A single sensitivity scenario models APS and PGE as not having joined the EIM by 2020.

Table 4. Overview of EIM Scenario Assumptions

Scenario	Renewable Energy Target (%)* IPC	CAISO	Other NW BAAs	Coal Capacity in WECC (GW)	BAAs in EIM Case
1. Base	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
2. No APS or PGE in EIM	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, IPC
3. Early Coal Retirements	15%	33%	15%	31.3	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
4. High RPS	20%	40%	20%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC

*PGE BAA includes non-PGE customers, resulting in a smaller renewable energy share of BAA load than RPS target; CAISO RPS includes renewable energy from out of state imports, does not reflect behind the meter PV generation.

Table 5. Renewable Capacity Added in High RPS Scenario (MW)

Region	Zone	Wind	Solar PV	Geothermal
FAR EAST	IPC		128	
MAGIC	IPC		132	
TREAS	IPC		112	
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NW	774		
BPA	NW	1,737	135	
PGE	NW	484		
SMUD	NW	498	616	
TIDC	NW		84	

2.5 Methodology for Attributing Benefits to IPC and Other Participants

To evaluate the benefits yielded by an EIM, we calculated the difference between procurement costs in a business-as-usual case and in an EIM case. There are three components of total procurement costs in our model: hour-ahead net import costs, real-time imbalance costs, and real-time generation costs. First, we define a few terms.

+ Hour-ahead net imports: the hourly difference between imports and exports.

+ Locational marginal price (LMP): a given BA's generation shadow price in a certain time period (the cost of generating an additional MWh of electricity).[12]
+ Real-time imbalance: the within-hour energy imbalance found in the EIM cases, where trading occurs at 10-minute intervals.
+ Average LMP: the imbalance-weighted average of all EIM BAs' LMPs.

Hour-ahead net import costs are calculated as the product of hour-ahead net imports and the locational marginal price, and then summed over all hours in the year. Real-time imbalance cost to a given BA is a 10-minute interval's imbalance multiplied by that interval's average LMP, summed over all 10-minute intervals in the year. Real-time generation costs include the variable costs of energy production modeled in PLEXOS – fuel prices (updated by E3 based on OTC Global Holding Natural Gas Forwards & Futures data provided by SNL), and variable operation and maintenance and unit startup costs (based on the costs characteristics for units in the TEPPC database, but not directly modified for this study).

Total savings associated with an EIM are the difference between the sum of hour-ahead net import costs, real-time imbalance costs, and real-time generation costs in the business-as-usual case and the EIM case. In all scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM cases, meaning the hour-ahead net import costs can be ignored in the

[12] The minimum LMP used for calculating benefits was set to -$100/MWh, which is the model's penalty price for overgeneration. In overgeneration conditions, renewable resources may be curtailed but also could require replacement costs for renewable energy to fulfill RPS goals in some jurisdictions.

calculation. Table 6 provides an example of benefits parsing that highlights the methodology discussed in this section.

Table 6. Benefits Parsing in the Base Scenario, IPC in Western EIM

Costs (2015$ million)*	Business-as-Usual	Western EIM	EIM Savings vs. BAU
Real-Time Generation and Import Costs	$108.8	$110.1	($1.3)
Real-Time Imbalance Costs (Market Revenues)	($0.1)	($5.9)	$5.8
Total Real-Time Procurement Costs	**$108.7**	**$104.2**	**$4.5**

Note: Individual estimates may not sum to total due to rounding. Positive values in the final column represent cost reductions, or savings in the EIM case relative to the BAU.

3 Results

3.1 Benefits to IPC

Table 7 below presents the simulated annual benefits of IPC participation in the EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to IPC as a result of its participation in the EIM. These savings are each calculated as the reduction in cost compared to the IPC BAU case. Overall, the dispatch cost savings range from $4.1 million in the early coal retirement scenario to $5.1 million in the high RPS scenario. Reduced reserves would provide additional savings in addition to these figures, though reserve reductions were not modeled for this study.

Table 7. Annual Benefits to IPC by Scenario, EIM (2015$ million)

Scenario	Dispatch cost savings to IPC
Base	$4.5
Sensitivity Scenarios	
No APS/PGE in EIM	$4.2
Early Coal Retirement	$4.1
High RPS	$5.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

EIM base scenario savings to IPC were $4.5 million with a decrease in annual real-time procurement costs (real-time generator production cost plus real time imbalance cost of purchases and revenue from sales) from \$108.7 million in the BAU case to \$104.2 million in the EIM case (a reduction of more than 4%). Section 3.3 goes into more detail for each sensitivity scenario.

3.2 Incremental Benefits to Current EIM Participants

Table 8 below presents the simulated incremental benefits resulting from IPC's EIM participation to the current participants in the EIM. IPC's EIM participation is expected to create \$2.2 to \$3.1 million in yearly savings to the current EIM participants across all scenarios.

Table 8. Annual Benefits to Current EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants
Base	$2.9
Sensitivity Scenarios	
No APS/PGE in EIM	$2.2
Early Coal Retirement	$3.0
High RPS	$3.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

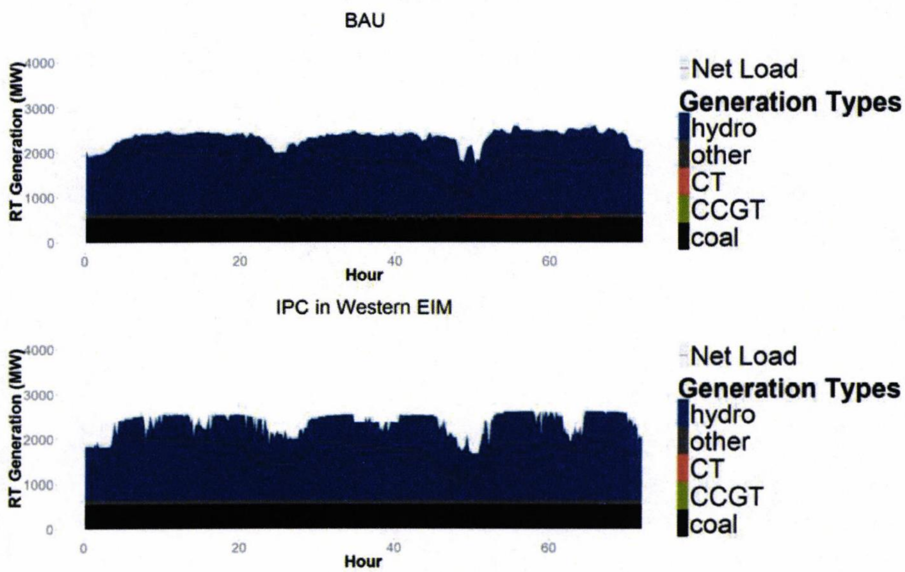
3.3 EIM Results Discussion

3.3.1 BASE SCENARIO

The base scenario brings $4.5 million of savings to IPC, as well as $2.9 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables IPC to export and import with other EIM participants in real time to respond to intra-hour imbalances. As illustrated in Table 6, IPC's real-time generation costs increase in the EIM, while its imbalance costs decrease by a larger amount. This is because, in the EIM, IPC can export its hydro generation extremely flexibly at 5-minute intervals, ramping the units up when LMPs are high and down when prices are low. A second benefit of EIM participation is smoother operation of thermal units; the real-time flexibility of the EIM prevents thermal generators from having to respond to within-hour imbalances (for the most part), decreasing ramping. This flexibility also allows IPC to avoid starting and running its CT generators at times.

The following chart illustrates all the benefits described above, displaying IPC's dispatchable generation in real time over a three-day period in the spring. In the EIM dispatch chart, hydro output is highly variable at the 10-minute level, in striking contrast to the smooth hydro output seen in the BAU case. Thermal generation is perfectly constant in the EIM case, whereas ramping is required in the BAU case. Furthermore, CT units are not used at all in the EIM case, whereas CT units are started and turned off at least four times in the BAU case.

Figure 3. IPC Real-Time Dispatchable Generation, Western EIM, April 28 – May 1



3.3.2 ALTERNATIVE SCENARIOS

Modeling APS and PGE as not in the EIM slightly reduces the size of the total EIM market and has a small downward impact on IPC savings relative to the base case, to $4.2 million.

The scenario with additional retirement of regional coal generators produces savings $0.4 million lower than the savings to IPC in the base scenario ($4.1 million in the early coal retirement case - $4.5 million in the base case). This difference is less than 10% of total savings, and is thus also fairly insignificant, indicating that model results for identified IPC savings are robust to participation and coal resource retirement.

The high RPS scenario brings $5.1 million of savings for IPC, which is $0.6 million higher than the savings in the base scenario. As expected, a higher renewable generation buildout increased savings to IPC, as the EIM allows resources from a wider area to address real-time variability in net load, and creates increased revenue opportunities for IPC's flexible hydro generation in the real-time market.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-19

IDAHO POWER COMPANY

ANDERSON, DI
TESTIMONY

EXHIBIT NO. 5

EIM Quarterly Benefit Report Methodology
Effective with Q1, 2016 EIM benefits report

Revision History

Date	Version	Description	Author
02/01/2016	1.0		Lin Xu
04/30/2016	2.0	Allow the ISO's units to be committed in the counter factual dispatch	Lin Xu

This document illustrates how the EIM benefit is calculated with an example. In the past, the ISO had discussed the method in Technical Bulletins and in the benefit reports. This document consolidates these prior materials into a concise paper for easier understanding.

The total EIM benefit is the cost saving of the EIM dispatch compared with a counterfactual (CF) without EIM dispatch. The counter factual dispatch meets the same amount of real-time load imbalance in each BAA without EIM transfers with neighboring EIM BAAs. For an EIM BAA, the benefit can take the form of cost savings or profit or their combination. A BAA will be likely to have energy cost savings when the BAA is importing energy economically, or its base schedules are being optimized by the EIM. A BAA will be likely to have an energy profit when the BAA is exporting energy economically to other BAAs, and being paid a price higher than the bid cost. A BAA, other than the ISO, may also have a GHG profit when the resource is allocated GHG MWs, and is receiving GHG revenue based on marginal GHG cost that is likely higher than its own GHG bid cost.

For each 5-minute interval, **EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost) + GHG revenue – GHG cost.** Then the 5-minute level EIM benefit are aggregated every month with a multiplier 1/12 to convert ($/5 min) to a dollar amount.

EIM benefit calculation components

EIM dispatch cost

The total dispatch cost for a BAA for an interval is the sum of all the unit level EIM dispatch cost for that BAA and for that interval.

For all other BAA's other than CAISO, the dispatch cost only includes variable dispatch cost, i.e. the bids submitted by the corresponding Scheduling Coordinator.

For the ISO's long start units, we only consider variable dispatch cost. For the ISO's short start units, we use a generic cost formula, which includes variable dispatch cost, startup cost, and no load cost. Specifically, the three-part cost include

- the variable dispatch cost of RTD, which is equal to the bid cost associated with the delta instruction above or below the base schedule for each interval,
- the no load cost associated with the incremental dispatch, which is equal to the no load cost divided by Pmax and then multiply it with the delta instruction from base schedule,
- the startup cost associated with the incremental dispatch, which is equal to the startup cost divided by the minimum online hours, and then multiply it with the delta instruction from base schedule divided by the Pmax.

The purpose for this generic cost formula is to evaluate cost differences between EIM dispatches and counter factual dispatches without performing sophisticated unit commitment simulations. Prior to Q1 2016, only variable dispatch cost was considered in the EIM benefit calculation. With NV Energy joining EIM and improving the transfer capabilities from and to the ISO, we observed significantly increased transfer volume in EIM. The higher transfer volume cannot be sufficiently replaced by resources online in EIM without committing or decomitting resources. That is why we adopted the three-part cost formula starting from Q1 2016 to allow for unit commitment decisions to better evaluate the production difference between EIM and the counter factual dispatch of the ISO. The unit commitments decisions were made only for short start units that are not combined cycle units. The combined cycle units had complicated models in EIM, so their counter factual commitment status are fixed at the EIM commitment status to avoid oversimplification.

We approximate the ISO's commitment costs by converting the startup cost and no load cost into variable dispatch cost, assuming a committed short start resource will be fully loaded for minimum online hours. For each supply segment, the corresponding three-part variable cost is equal to

bid_price + no_load_cost/Pmax + startup_cost/min_up_hour/Pmax

Note the formula above converts startup cost (in unit $) and no load cost (in unit $/h) into variable dispatch cost (in unit $/MWh). By doing this, the commitment for the ISO's units can be determined based on the economic metric order of the three-part variable cost.

Transfer cost

As a convention, select the importing direction as the default direction for a transfer, so importing transfer is positive and exporting transfer is negative. The transfer cost is equal to the transfer MW times the transfer price. For an importing BAA, the transfer price is the LMP of the BAA minus half of the absolute value of the transfer shadow price. For an exporting BAA, the transfer price is the LMP of the BAA plus half of the absolute value of the transfer shadow price. Transfer could occur in both the 15-minute market and the 5-minute market. In this case, the transfer cost is 15-minute transfer * 15-minute transfer price + (5-minute transfer – 15-minute transfer) * 5-minute transfer price for each 5-minute interval.

Counterfactual dispatch cost

The counterfactual dispatch for an EIM BAA mimics the market operations without importing or exporting through the EIM transfers. The counterfactual dispatch moves units inside the BAA to meet the same real-time load imbalance as the EIM dispatch without considering transmission constraints. However, for PacifiCorp, the transfer limit between PACE and PACW is enforced in the counter factual dispatch. Relaxing transmission constraints tends to under estimate the counterfactual dispatch cost and the EIM benefit. However, because few transmission constraints were observed binding in EIM, it is unlikely the EIM benefit will be significantly under estimated.

The counterfactual dispatch makes unit commitment decisions only for the ISO's short start units. The unit commitment decisions are based on the generic three-part variable cost formula, which has converted startup cost and no load cost into variable dispatch cost. So unit commitment can be determined by the economic metric order of the three-part cost.

In cases where a counterfactual dispatch could not be produced for a BAA using available bids, the highest bid dispatched will be extended as the marginal cost for procuring more supply. An EIM BAA may restrict the pool of dispatchable units in the counterfactual dispatch if that the BAA's practice prior to joining EIM was to balance real-time load from a limited pool.

ISO counterfactual dispatch

The ISO would need to meet load without EIM transfers in the counterfactual dispatch. The counterfactual dispatch is constructed in the following way.

1. Calculate the ISO's net EIM transfer;
2. Economically dispatch resources from the ISO to replace the transfer
   A. If the ISO is importing from the EIM,
      a. Find the ISO's undispatched supply with the variable cost (bid and three-part converted) greater than or equal to the transfer price;
      b. Sort and stack the supply by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the transfer megawatts
   B. If the ISO is exporting to the EIM,
      a. Find the ISO's dispatched supply with the variable cost (bid and three-part converted) less than or equal to the transfer point price;
      b. Sort and stack them by the variable cost from high cost to low cost; and
      c. Clear the supply stack from high cost to low cost up to the transfer megawatts

NV Energy counterfactual dispatch

NV Energy's counter factual dispatch is constructed in the following way.

1. Calculate the real-time net load imbalance for NVE;
2. Economically dispatch resources from NVE on top of the base schedules to meet NVE's net load imbalance
   A. If the net load imbalance is positive,

    a. Find NV Energy's bid-in supply above base schedules;
    b. Sort and stack them by the variable cost from low cost to high cost; and
    c. Clear the supply stack from low cost to high cost up to the net load imbalance.
  B. If the net load imbalance is negative,
    a. Find NV Energy's bid-in supply below base schedules;
    b. Sort and stack them by the variable cost from high cost to low cost; and
    c. Clear the supply stack from high cost to low cost up to the net load imbalance.

PacifiCorp counterfactual dispatch

PacifiCorp East BAA and PacifiCorp West BAA would need to meet demand without intra-hour transfers between PacifiCorp and the ISO, but transfers could occur between PACE and PACW in the counterfactual dispatch. The PacifiCorp counter factual dispatch will be constructed in the following way:

1. Calculate the real-time net load imbalance for each BAA;
2. Economically dispatch resources from the limited pool on top of the base schedules to meet net PacifiCorp load imbalance without violating the transfer limitations between PACE and PACW.
   A. If the net load imbalance is positive,
      a. Find PacifiCorp's bid-in supply above base schedules;
      b. Sort and stack them by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the net load imbalance subject to the transfer limit between PACE and PACW
   B. If the net load imbalance is negative,
      a. Find PacifiCorp's bid-in supply below base schedules;
      b. Sort and stack them by the variable cost from high cost to low cost; and
      c. Clear the supply stack from high cost to low cost up to the net load imbalance subject to the transfer limit between PACE and PACW

GHG revenue

Greenhouse gas (GHG) revenue for a resource is equal to its GHG allocation MW times the GHG price.

GHG cost

GHG cost for a resource is equal to its GHG allocation MW times its GHG bid.

Example

This example illustrates how the EIM benefit is calculated.

The transfers out of the EIM optimization are listed below. Base scheduled transfers have been excluded in the FMM transfers and RTD transfers.

from BAA	to BAA	FMM transfer	FMM transfer price	RTD incremental transfer	RTD transfer price	transfer cost
PACE	NEVP	140	$26	10	$25	$3,890
NEVP	CISO	160	$26	20	$30	$4,760
PACE	PACW	190	$26	10	$25	$5,190
PACW	CISO	110	$26	-10	$30	$2,560

BAA to BAA transfers and prices

Assume the EIM energy imbalance and prices are as follows. Every BAA is balanced with Gen + Transfer – Load = 0. Assume the EIM optimization results in $1 GHG price, which means the ISO's LMP is $1 higher than the neighboring BAA (NEVP and PACW), because there is no congestion going into the ISO in the example. In the table below, positive transfer MW means the BAA is importing and negative transfer MW means it is exporting. Also, transfers in the table are sum of the transfers occur in both the FMM and the RTD with base scheduled transfer being excluded.

BAA	Gen	Load	Net transfer in MW	LMP	GHG price
CISO	0	280	280	$31	$0
NEVP	50	20	-30	$30	$1
PACE	150	-200	-350	$20	$1
PACW	100	200	100	$30	$1

EIM energy imbalance and prices by BAA for one 5-minute interval

Transfer cost

The transfers occur in both FMM and RTD, and their volume and prices are listed below. They are calculated from applying the convention that importing is positive and exporting is negative the BAA to BAA transfers, and summing them over all the neighboring BAAs.

BAA	transfer cost
CISO	$7,320 = $4,760+$2,560
NEVP	($870) = $3,890-$4,760

PACE	($9,080) = -$3,890-$5,190
PACW	$2,630 = $5,190-$2,560

EIM transfer cost by BAA

EIM dispatch cost

Now calculate the total bid cost associated with the EIM dispatches (delta from base schedules). The EIM dispatch costs are listed below.

BAA	Gen_EIM	EIM dispatch cost
CISO	0	$0
NEVP	50	$1,450
PACE	150	$2,700
PACW	100	$2,800

EIM dispatch cost by BAA

Counterfactual dispatch cost

Then construct the counter factual dispatches as described in the previous section, and sum up the counter factual dispatch cost for each BAA.

BAA	Gen_CF	Counterfactual dispatch cost
CISO	280	$9,240
NEVP	20	$640
PACE	-200	($3,800)
PACW	200	$6,200

Counterfactual dispatch cost by BAA

GHG cost and revenue

The GHG costs associated with the 280 MW of importing transfer into CISO, and the revenues received by the GHG allocated MWs in both FMM and RTD are listed below.

BAA	GHG FMM MW	GHG RTD MW	GHG cost	GHG revenue
CISO	0	0	$0	$0
NEVP	0	0	$0	$0
PACE	200	200	$20	$200
PACW	70	80	$75	$80

GHG cost and revenue by BAA

EIM benefit

With all the cost and revenue for each BAA available, we can use the formula EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost) + GHG revenue – GHG cost to calculate EIM benefit for each BAA.

BAA	CF dispatch cost	EIM dispatch cost	Transfer cost	GHG cost	GHG revenue	EIM benefit
CISO	$9,240	$0	$7,320	$0	$0	**$1,920**
NEVP	$640	$1,450	($870)	$0	$0	**$60**
PACE	($3,800)	$2,700	($9,080)	$20	$200	**$2,760**
PACW	$6,200	$2,800	$2,630	$75	$80	**$775**

EIM benefit for one 5-minute interval

This calculation is performed for each 5-minute interval with unit $/hr. We convert the $/hr benefit into the dollar benefit by multiplying 1/12. Then the 5-minute interval benefits in dollar amount can be aggregated into the monthly benefit by summing all the 5-minute intervals in the month.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-19

IDAHO POWER COMPANY

ANDERSON, DI
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EXHIBIT NO. 6

Benefits for Participating in EIM

July 28, 2016

Revision History

Date	Version	Description	Author
07/29/2016	1.0		Lin Xu

Table of Contents

Executive Summary

This is the "Quantifying EIM Benefits" report for the second quarter of 2016. The estimated gross benefits for April, May and June 2016 are $23.60 million. This brings the EIM total benefits to $88.19 million since it expanded the real-time market to balancing areas outside the California ISO starting in November 2014.

The total gross benefits for Q2 2016 increased from the last quarter driven by seasonal changes in supply and demand. A similar trend was also observed in 2015 from Q1 to Q2.

The benefit calculation method is described in a separate document.[1] This analysis demonstrates the EIM's ability to select the most economic resources across the PacifiCorp, NV Energy and the California ISO balancing authority areas (BAAs) that comprise the EIM footprint. The benefits quantified in this report fall into three categories and were described in earlier studies.[2]

- ***More efficient dispatch, both inter- and intra-regional, in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD),*** by automating dispatch every fifteen minutes and every five minutes within and across the EIM footprint, including the California ISO, PacifiCorp, and NV Energy.

- ***Reduced renewable energy curtailment,*** by allowing balancing authority areas to export or reduce imports of renewable generation when they would otherwise need to be economically curtailed, and

- ***Reduced flexibility reserves needed in all balancing authority areas,*** which saves cost by aggregating the load, wind, and solar variability and forecast errors of the combined EIM footprint. This report quantifies the diversity benefits of flexibility reserves for the entire EIM footprint.

Table 1 shows the estimated gross benefits summary for the second quarter of 2016 in millions of dollars per EIM entity.

Region	April	May	June	Total
CAISO	2.56	2.24	3.09	**7.89**
NV Energy	1.09	1.34	2.77	**5.20**
PacifiCorp	4.63	2.44	3.44	**10.51**
Total	8.27	6.03	9.30	**23.60**

Table 1: Estimated gross benefits shown are in millions and accrued in the second quarter of 2016

[1] EIM Quarterly Benefit Report Methodology, https://www.caiso.com/Documents/EIM_BenefitMethodology.pdf
[2] PacifiCorp-ISO, Energy Imbalance Markets Benefits, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

One of the significant contributions to the EIM benefits are transfers across the balancing areas which provide lower supply cost, even while factoring in the cost of compliance with greenhouse gas (GHG) emissions cost when it is transferring into the ISO. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the Fifteen Minute Market (FMM) and Real-Time Dispatch (RTD). Generally, the transfer limits are based on transmission rights and interchange rights that participating balancing authority areas make available to EIM, with the exception of the PACW-ISO transfer limit in RTD. The RTD transfer capacities between PACW and the ISO are dynamically determined based on the allocated dynamic transfer capability driven by system operating conditions. This report does not quantify a BAA's opportunity cost that the utility considered when using its transfer rights for the EIM.

Balancing authority areas may submit base scheduled transfers. These transactions occurred between NV Energy and PACE. The EIM inter-regional benefits are calculated based on the transfer difference between the EIM and the base schedule. This is because the benefits associated with base scheduled transfers, to the extent that they exist, should be attributed to decisions made prior to the EIM, not to the economic efficiencies gained through the EIM.

While market conditions will vary, the EIM continues to provide benefits to participating entities and their customers as demonstrated in this report.

NV Energy's EIM benefits mainly reflect inter-regional transfer benefits resulting from intra-hour transactions. This is attributed to NV Energy's optimization of its base schedules prior to submission to the EIM.

Background

The EIM began financially-binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs, which includes portions of California, Oregon, Washington, Utah, Idaho and Wyoming. NV Energy, operating in Nevada, began participating in December 2015. The EIM facilitates renewable resource integration and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region. The ISO started publishing quarterly EIM benefit reports in January 2015. As other BAAs join the EIM, this report will expand to include the benefits associated with their participation.

EIM Benefits in Q2 2016

Table 1 breaks out the estimated EIM gross benefits by each BAA per month. The savings presented in the table show \$8.27 million for April, \$6.03 million for May, and \$9.30 million for June.

Inter-regional Transfers

One of the significant contributions to the EIM benefits is transfers across the balancing areas which provide lower supply cost. Table 2 provides the 15-minute EIM transfer volume and the 5-minute EIM transfer volume, both with base schedule transfer excluded. NV Energy and PACE had submitted base schedule transfers. The EIM benefit is only attributable the transfers that occurred with EIM, but not the base schedules submitted prior to the EIM.

The transfer from BAA_x to BAA_y and the transfer from BAA_y to BAA_x are separately reported. For example, in an interval, if there is 100 MWh transfer on top of base transfer from CISO to NEVP, it will be reported as 100 MW with from_BAA=CISO and to_BAA=NEVP, and it will be reported as 0 MW with from_BAA=NEVP and to_BAA=CISO in the opposite direction. The 15-minute transfer volume results from EIM optimization in the 15-minute market with all bids and base schedules submitted into EIM. The 5-minute transfer volume results from EIM optimization in the 5-minute market with all bids and base schedules submitted into EIM, and unit commitments determined in the 15-minute market optimization.

The ISO continued to export a significant amount of energy to NV Energy and PacifiCorp in this quarter, which was first observed in Q1 2016. It is also worth noting that a significant level of energy that was exported by the ISO consisted of renewable generation.

Year	Month	from_BAA	to_BAA	15m EIM transfer (15m - base)	5m EIM transfer (5m - base)
2016	April	CISO	NEVP	151,098	141,142
2016	April	CISO	PACW	10,899	11,286
2016	April	NEVP	CISO	48,422	73,963
2016	April	NEVP	PACE	118,420	123,547
2016	April	PACE	NEVP	38,270	41,397
2016	April	PACE	PACW	10,354	21,736
2016	April	PACW	CISO	76,026	81,880
2016	May	CISO	NEVP	178,120	158,983
2016	May	CISO	PACW	27,561	27,804
2016	May	NEVP	CISO	29,820	62,126
2016	May	NEVP	PACE	134,092	133,344
2016	May	PACE	NEVP	24,513	29,969
2016	May	PACE	PACW	13,800	25,499
2016	May	PACW	CISO	54,856	52,302
2016	June	CISO	NEVP	151,491	134,804
2016	June	CISO	PACW	42,772	44,661
2016	June	NEVP	CISO	55,793	87,306
2016	June	NEVP	PACE	52,150	63,785
2016	June	PACE	NEVP	77,205	76,448

2016	June	PACE	PACW	36,809	52,867
2016	June	PACW	CISO	36,723	39,296

Table 2: Energy transfers (MWh) in the FMM and RTD for the second quarter of 2016

Reduced Renewable Curtailment

The EIM helps avoid renewable curtailments within the ISO, which has both economic and environmental benefits. The EIM benefit calculation includes the economic benefits that can be attributed to avoided renewable curtailment within the ISO. If not for energy transfers facilitated by the EIM, some renewable generation located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q2 2016 was calculated to be 67,373 MWh (April) + 49,296 MWh (May) + 42,136 MWh (June) = 158,806 MWh total. The energy being exported by the ISO included a significant level of renewable generation.

The environmental benefits of avoided renewable curtailment are significant. Under the assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO_2/MWh, avoided curtailments displaced an estimated 67,969 metric tons of CO_2 for Q2 2016. Avoided renewable curtailments may also have reduced the volume of renewable credits that would have been retracted. However, this report does not quantify the additional value in dollars associated with this benefit.

Flexible ramping procurement diversity savings

The EIM facilitates procurement of flexible ramping capacity in the FMM to address variability that may occur in the RTD. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirement. This difference is known as the flexible ramping procurement diversity savings. Starting in June 2015, the ISO implemented an automated tool to analyze historical uncertainties and calculate the flexible ramping requirement for each BAA in the EIM. In Q2 2016, the flexible ramping requirement for the ISO varied from 300 MW to 500 MW, the requirement for PACE varied from 91 MW to 150 MW, the requirement for PACW varied from 60 MW to 100 MW, and the requirement for NVE varied from 80 MW to 100 MW. Due to the reduction in flexible ramping requirement associated with the larger EIM footprint, the total requirement across the four BAAs varied from 400 MW to 530 MW.

The flexible ramping procurement diversity savings for all the intervals averaged over a month are listed in Table 3. The percentage saving is the average MW savings divided by the sum of the four individual BAA requirements.

	April	May	June
Average MW saving	281	280	270
Sum of BAA requirements	777	770	758
Percentage savings	36%	36%	36%

Table 3: Flexible ramping procurement diversity saving for the second quarter of 2016

Under the current flexible ramping constraint design, the procured flexible ramping capacity can be fully accessed in RTD. If the flexible ramping procurement in the FMM is beneficial, it will reduce the RTD dispatch cost. With the EIM benefits being quantified on a 5-minute level, the benefit of flexible ramping is fully captured in the RTD dispatch. The EIM benefits calculated at a 5-minute level includes the savings from procuring and deploying flexible ramping. However, this analysis does not breakout the dollar savings separately because the savings are tightly integrated with the RTD dispatch.

Conclusion

The EIM continued to show significant benefits during the second quarter of 2016. The total benefits for the quarter of $23.60 million are consistent with pre-launch studies, and reflect the transfer benefits of a more robust EIM footprint, that includes both PacifiCorp and NV Energy.