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February 12, 2018

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
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RE: Docket No. UE 333 – In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism.

Attached for filing are the following exhibits:

UE 333 Exhibit 100 – 102 Anderson

UE 333 Exhibit 200 Kaufman Redacted, pages 7-8 are confidential
UE 333 Exhibit 201 - 202 Kaufman
UE 333 Exhibit 203 Kaufman Non-Confidential
UE 333 Exhibit 204 Kaufman

UE 333 Exhibit 300-302 Fox and

UE 333 Exhibit 400-402 Gibbens

Exhibit 200 Confidential pages 7-8 and Confidential Exhibit 203 is being mailed to parties who have signed Protective Order 17-443.

/s/ Kay Barnes

Kay Barnes
PUC- Utility Program
(503) 378-5763
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CERTIFICATE OF SERVICE

UE 333

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 12th day of February, 2018 at Salem, Oregon

Kay Barnes

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UE 333 SERVICE LIST

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CASE: UE 333
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

February 12, 2018

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I provide an overview of the Idaho Power Company's (Idaho Power, Company, or IPC) 2018 Automatic Power Cost Update (APCU) filing and Staff's analysis. I also address the Public Utility Regulatory Policies Act (PURPA) expense forecast and load forecast in more depth.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/102, Staff Analysis Based on Idaho Power Response to Staff Data Request No. 03.

Q. How is your testimony organized?

My testimony is organized as follows:

Q. Please describe the Idaho Power Annual Power Cost Update (APCU).

A. The Commission adopted the APCU in Order No. 08-238 to provide Idaho Power with timely recovery of its “net power supply expense” (NPSE).[1] The APCU has two components, the October Update and March forecast, both of which may result in an adjustment to Idaho Power’s rates. The October Update is based on specific inputs to the AURORA model used to forecast power costs and establishes a “baseline” or “normal” forecast based on multiple historical water years. The March Forecast is a forecast of expected power supply expense for the same April through March test period, but calculated by modeling a single forecast water condition from the Northwest River Forecast Center. The October Update filing results in an update to base rates. Any change resulting from the March Forecast is reflected in a separate tariff, Idaho Power’s Schedule 55. Both the base rate change and change to Schedule 55 are effective July 1 of the year following the October Update.

Q. Did the Company propose any modeling changes in the APCU?

A. No, in this year’s filing, IPC did not make any proposed model changes.

Q. Please describe what inputs the Company may update in the October Update.

A. Per Order 08-238, the Company updates the following inputs:

a. Fueling prices and transportation costs;

b. Planned outages and forced outage rates;

c. Heat rates;

d. Forecast of Normalized Load and Normalized Sales;

[1] Order No. 08-238.

e. Contracts for wholesale power and power purchases and sales;

f. Forward price curve;

g. PURPA contract expenses;

h. The Oregon state allocation factor; and

i. Wheeling Expense.

Q. How does Idaho Power's projection of NPSE compare with previous actual NPSE?

A. The October Update predicts an April-March NPSE of $397.2 million. The total "net power supply expense" (NPSE) in the Company's most recent true-up (UE 320) was approximately $412.2 million for the 2016 calendar year. Idaho Power's current projection of NPSE is approximately 3.6 percent lower than the 2016 actual NPSE.

Q. How does Idaho Power's projection of NPSE compare with the previous October Update projection of NPSE?

A. The October update is an increase from the 2017 forecast of $382.1 million to $397.2 million, or about four percent.

Q. What are the drivers of Idaho Power's increased NPSE?

A. The main drivers of the increase in system NPSE since the 2016 October Update (for the 2017 APCU) are increased per-unit coal costs, increased natural gas prices, and decreased surplus sales revenue. Per-unit coal costs increased overall largely because coal fired generation decreased 18 percent, while coal fuel expense decreased only nine percent. The natural gas price forecast for the 2017 October Update increased four percent from the 2016 October Update, resulting from an increase in US gas consumption and a decrease in storage since last year. Surplus sales revenue decreased 37 percent in the 2018 APCU because of decreased market prices.

Q. What issues does Staff address in its Opening Testimony?

A. I address Idaho Power's forecast of expense for PURPA contracts, Idaho Power's general compliance with the APCU methodology, and Idaho Power's agreement to provide work papers relating to its load forecast.

Staff witness Lance Kaufman addresses Staff's review of the method Idaho Power uses to allocate costs between Idaho Power's Oregon and Idaho jurisdictions and between Oregon rate classes; recovery of depreciation expense for plant owned by a subsidiary; and Idaho Power's long-term fuel plan for its Bridger Plant.

Staff witness Scott Gibbens testifies regarding Idaho Power's recovery of costs and benefits of participation in the Energy Imbalance Market (EIM).

Staff Witness John Fox reports on his review of power cost accounting data from Idaho Power.

Staff has not identified any issues with respect to the other inputs. However, Staff is continuing to investigate Idaho Power's heat rates and planned and forced outage rates.

Q. Does Staff recommend any adjustments to Idaho Power's forecast of NPSE?

A. Mr. Kaufman recommends a downward adjustment to NPSE to remove depreciation expense for plant acquired by the subsidiary since Idaho Power's last general rate case. Mr. Gibbens recommends making benefits and non-capital costs of Idaho Power's first year of participation in the EIM subject to recovery under a separate deferral. Mr. Gibbens recommends that Idaho Power recover EIM capital investment in a general rate case.

ISSUE 1. GENERAL COMPLIANCE

Q. Has Staff identified any issues with how Idaho Power has modeled its NPSE?

A. No. Staff's analysis to date shows that Idaho Power has complied with the methodologies previously adopted by the Commission. Staff has only identified concerns with some of the expense that Idaho Power includes in its calculation of NPSE.

Q. You note that the primary drivers of the relatively small increase in NPSE are lowered natural gas price forecast, lower market prices, and increased per-unit coal costs. Does Staff have concerns related to these inputs?

A. Staff has not identified any concerns with Idaho Power's market-price forecasts or its natural gas price forecast. Staff also does not take issue with Idaho Power's calculation of coal prices.

ISSUE 2. OHAG EXPENSES

Q. What are Oil, Handling, Administrative, and General (OHAG) expenses and how are they included in Idaho Power's NPSE?

A. OHAG expenses include the costs of diesel burned at the plant for startup and flame stabilization; labor, equipment, materials, supplies and related overhead loadings on these costs to move coal from the train trestle (or in the case of Bridger, the conveyor) to the coal silos; and labor associated with coal fuel procurement and routine fuel analysis.[2] Actual OHAG expenses vary depending on overall production at each plant.

In Docket Nos. 301 and 314 regarding Idaho Power's 2016 and 2017 APCU filings, the Commission adopted stipulations in which parties agreed to methodological changes to how Idaho Power modeled OHAG expenses. The UE 301 stipulation adopted a hybrid model (Hybrid Model) methodology that separately accounted for OHAG costs associated with Idaho Power's dispatch of the coal plants and the proportional share of total OHAG costs Idaho Power is required to pay to its co-owners.[3] Under the Hybrid Model agreed to by the parties to Docket No. UE 301, Idaho Power would include only the portion of OHAG expenses associated with Idaho Power's dispatch in the AURORA model while separately accounting for Idaho Power's proportional share of OHAG expenses resulting from its partners' dispatch.

[2] UE 301 Idaho Power/100, Blackwell/6.
[3] Order No. 16-206, App. A.

In Docket No. UE 314, the Commission adopted the parties' stipulation regarding Idaho Power's forecast of OHAG costs. Under the UE 314 stipulation, the forecast is based on a three-year historical average of actual OHAG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate.[4]

Q. Did Idaho Power calculate OHAG expenses consistently with the previously adopted methodology?

A. Yes, Staff reviewed the calculation to ensure the Company followed the methodology set forth in UE 314 and UE 301.

Q. Does Staff agree with Idaho Power's calculation of OHAG in the 2018 APCU?

A. Yes. Staff found no issues with the calculations. The forecast OHAG amounts utilizes the Hybrid Model methodology and calculates the forecast expense utilizing the proper historical data and trend.

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[4] Order No. 17-165, p. 4.

ISSUE 3. QUALIFYING FACILITIES

Q. What are the changes in forecast qualifying facility (QF or PURPA) generation since the 2017 October Update?

A. The forecast of generation from QFs has decreased 20 aMW since last year's October Update. This change is driven by the expiration of a sales agreement from a 10-MW cogeneration project and a decrease in forecast generation for several other projects.

Q. How accurate has the PURPA forecast been in recent years?

A. The PURPA forecast was reasonably accurate in the 2014 and 2015 APCU filings. However the forecast in the 2016 APCU was 20 percent above actual PURPA expenses for the 2016 power cost year. The forecast for the 2016 power cost year was $208,893,400, yet actual PURPA expenses were only $174,311,189. This 19.8 percent difference is significant and of particular concern given that PURPA expense is the largest category in Idaho Power's variable power cost filing. PURPA expense comprises about 50 percent of total power cost expenses. In the two previous power cost years, the error was much smaller. The PURPA forecast exceeded actuals by 2.3 percent in the 2014 power cost year and by 8.1 percent in the 2015 power cost year.[5]

Q. What is Staff's understanding of the causes of the over-estimation of PURPA expenses in the 2016 APCU?

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[5] Staff/102, Anderson/1.

A. The reasons for the trend toward over-estimating PURPA expenses in the APCU are unclear. Staff is currently waiting on discovery response from Idaho Power regarding the Company's PURPA forecasting process.

Q. What does Staff recommend for the PURPA forecast in Idaho Power's APCU?

A. In the 2018 APCU, Idaho power made downwards adjustments to the forecast generation for certain QFs, resulting in a decrease of about 7.3 aMW or two percent. This may serve to improve the accuracy of the forecast. However, Staff recommends that Idaho Power explain the reasons PURPA expenses were over-estimated to such a large degree in the 2016 APCU and propose steps to remedy any issues with the PURPA forecast if necessary.

ISSUE 4. LOAD FORECAST

Q. Please describe parties' agreement regarding the load forecast in Docket No. UE 314, Idaho Power's 2017 APCU.

A. In the stipulation in UE 314, the stipulating parties agreed that Idaho Power would host a conference call to discuss workpapers for the Company's load forecast. The workshop was held on September 18, 2017.

Q. What did the stipulating parties agree to at the workshop?

A. Idaho Power agreed to file the following workpapers with the 2018 APCU:

- Model output files in Excel format including coefficients, model statistics, and predictions for each equation utilized to develop the forecast for residential, commercial, industrial, and irrigation customers.
- A model key, which provides variable names and definitions for each of the model output files noted above.
- 30-year historical temperature data by weather station, including minimum and maximum daily temperatures, as well as daily precipitation values.
- 30-year historical monthly weather station weighting factors by residential and commercial classes.

Q. Did the Company provide the workpapers as agreed in the Stipulation?

A. Yes. The workpapers Idaho Power filed in October 2017, for the load forecast used in the 2018 APCU, reflect the agreement reached at the workshop. Additionally, the Company provided the mathematical equations used to model the load forecasts in the 2018 APCU in response to a Staff data request. Staff appreciates the Company providing access to the materials necessary to review the load forecast in the 2018 APCU filing.

Q. Has Staff identified any issues with Idaho Power's load forecast in this filing?

A. No. Staff has reviewed the workpapers provided with the Company's load forecast and has identified no issues at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 333
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

February 12, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Rose Anderson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA Bachelor of Arts, International Political Economy University of Puget Sound, Tacoma, WA
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Utility Analyst in the Energy Rates, Finance and Audit Division. My current responsibilities include review of Affiliated Interest filings and utility labor cost analysis. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UE 333
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

February 12, 2018

Idaho Power Company
Actual PURPA expense v forecast

2014-2015 Power Cost Year			
		Total	
Actual	$	162,131,428	
Forecast	$	165,900,000	
% Difference			2.32%

2015-2016 Power Cost Year			
		Total	
Actual	$	159,798,289	
Forecast	$	172,800,000	
% Difference			8.14%

2016-2017 Power Cost Year			
		Total	
Actual	$	174,311,189	
Forecast		208,893,400	
% Difference			19.84%

CASE: UE 333
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

February 12, 2018

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I address issues related to how power costs are allocated between Idaho Power's Oregon and Idaho jurisdictions and between Oregon rate classes; the recovery of depreciation expense for capital investments made by an Idaho Power Joint Venture; and the Jim Bridger long-term fuel plan.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/202, which is Idaho Power Responses to Staff DR Nos. 13, 15, 16, 17, 18, and 19; Exhibit 203, which is Idaho Power Confidential Responses to Staff DRs 18 and 19, and Exhibit 204, which is a workshop presentation regarding the Jim Bridger Fuel Plan.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. RATE SPREAD

Q. Please summarize the issue related to rate spread.

A. In Idaho Power's 2017 Annual Power Cost Update (APCU) parties stipulated that in future APCU filings Idaho Power would use the Staff-proposed "total cost method" to allocate power costs between Idaho Power's Idaho and Oregon jurisdictions and among rate classes in Oregon. Idaho Power testifies in its Opening Testimony that it used the total cost allocation method, and also filed workpapers summarizing the calculations. Staff's initial review indicates that it appears Idaho Power did use the total cost allocation method and that Idaho Power's calculations appear correct. However, because Staff has been unable to determine what portions of Idaho Power's rates are intended to collect power costs, it is not yet possible to say with certainty that the method has been applied appropriately.

Q. Why has Staff been unable to verify past power cost rates?

A. Idaho Power's tariff does not distinguish between base power cost rates and base non-power cost rates. Because of this Staff has a limited ability to audit Idaho Power's filings.

Q. How did Idaho Power allocate costs and design rates in previous dockets?

A. Idaho Power did not allocate total power costs each year. Instead, Idaho Power used a rate update mechanism to allocate expenses incremental to the previous year. For example, for the 2017 APCU, Idaho Power used the following process to allocate incremental power costs:

1. Estimate total system power cost (estimated at $382 million).
2. Estimate system load (estimated to be 14.6 million MWh).
3. Divide total cost by system load to obtain a cost per megawatt (= $26.06).
4. Determine the difference between the 2016 APCU cost per megawatt hour of $23.93 and the 2017 APCU update cost per megawatt hour to arrive at an incremental cost (= $2.13 per megawatt hour).
5. Calculate the Oregon jurisdictional "Incremental Net Power Cost Expense" (INPCE) by multiplying the forecasted Oregon load for the test period (686,534) by the incremental cost per megawatt hour (= $1,462,318).
6. Calculate incremental rate needed to recover incremental amount.

Q. What was Staff's concern with Idaho Power's incremental rate process in Docket No. UE 314?

A. The incremental mechanism does not account for the fact that each service schedule has a different power cost rate and a different load growth rate. Depending on which service schedules are driving load growth, Idaho Power's methodology may over or under collect rates. Also, as already discussed, it is very difficult to unwind incremental rate changes to determine exactly how much Idaho Power is recovering for power costs.

Q. What is the total cost method Staff proposed to address this issue?

A. Under Staff's proposed methodology, Idaho Power resets and allocates total Net Power Supply Expense (NPSE) each year rather than making an incremental change to rates for NPSE one year to the next. More specifically, Idaho Power calculates the Oregon jurisdictional share of the APCU revenue requirement by multiplying the system NPSE total per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the April through March test period. Idaho Power also calculates rates by allocating total power cost expense to service schedules rather than incremental expense.

Q. Does Staff have concerns with Idaho Power's application of the total cost method in the 2018 APCU?

A. As noted above, Staff has yet to determine whether Idaho Power correctly applied the total cost method. Staff cannot compare Idaho Power's current rates for power costs to previous rates because Idaho Power's base rates are for both power and non-power costs. Staff believes it is necessary to have separate rates for power costs and non-power costs to allow an adequate review of Idaho Power's APCU. In workshops Staff recommended that Idaho Power maintain separate rates for power costs and non-power costs. Staff will continue to work with Idaho Power to develop tariffs that meet Staff's transparency needs.

In this docket, Staff will continue its investigation of rates applied in previous years to determine if the 2018 APCU rates were appropriately calculated.

ISSUE 2. BRIDGER COAL COMPANY

Q. Please summarize Staff's analysis of Bridger Coal Company (BCC).

A. In Idaho Power's 2017 APCU Staff raised concerns related to BCC depreciation expense. The settlement of the 2017 APCU did not resolve these concerns on a permanent basis. Idaho Power continues to recover depreciation expense from customers for plant that has not been reviewed for prudence. The depreciation rate for such plant is also much higher than that supported by the plant's useful life.

Q. What is BCC's relationship to Idaho Power?

A. BCC is a joint venture of Idaho Power and PacifiCorp and comprises Idaho Energy Resources Co. (IERCO), a wholly owned subsidiary of Idaho Power, and a separate subsidiary of PacifiCorp. Pursuant to Commission order, "separate records and accounts for IERCO are maintained and the operations of IERCO as a joint venture in Bridger are subject to regulatory review and scrutiny together with those of Idaho during general rate cases. The operations of IERCO are summarized in Idaho's semiannual reports of operations filed with the Public Utility Commission. IERCO's results of operations have been merged, consolidated, and included with Idaho's for the purposes of filing of income tax returns and for rate-making purposes."[1]

Q. Please explain how BBC's status as an affiliated interest affects the rate that BCC charges Idaho Power.

[1] Order No. 91-567; *In re Idaho Power Company.*

A. The rate that BCC charges is subject to OAR requirements regarding affiliated interests. However, the treatment of BCC differs from the treatment of most affiliates because Idaho Power's investment in BCC rates is included in Idaho Power's rate base for ratemaking purposes. This means that Idaho Power's base rates include a component for a return on Idaho Power's investment in BCC. However, Idaho Power's base rates do not include any other BCC costs. BCC charges Idaho Power a cost-based rate for coal that includes all costs except the return on investment recovered though Idaho Power's base rates. Accordingly, the coal price does include the return of investment, which is depreciation expense. This treatment appears to be unique to BCC. While the Commission has accepted the treatment in past cases, Staff finds that the treatment should be re-examined.

Q. Is BCC plant subject to prudence review by the Commission?

A. Yes, as part of general rate cases, BCC plant is subjected to a prudence review by the Commission.

Q. Depreciation is not normally included in power costs. Please explain why Idaho Power is including BCC depreciation expense in power costs.

A. BCC is operated as an affiliated interest of Idaho Power. The price that BCC charges Idaho Power for coal is based on the actual operating costs of BCC, including depreciation expense.[2] Depreciation expense is folded into fuel costs, which is included in the APUC as a variable power cost.

[2] Staff Exhibit 202; Idaho Power Response to Staff DR Nos. 13, 16, 17, and 18.

Q. Please summarize BCC post rate case plant and depreciation expense.

A. Idaho Power filed its last general rate case in July 2011. Bridger Coal Company has made [redacted][3] in gross plant additions between January 1, 2011 and December 31, 2017. Over the same period BCC has accumulated [redacted][4] in depreciation reserves for the same plant, and will charge [redacted] in depreciation expense for this plant in 2018. [redacted] of all post rate case plant additions have been fully depreciated so the associated depreciation expense will never be subject to a prudence review.[5]

Q. Should depreciation expense associated with post rate case plant additions be included in rates?

A. No. Post rate case plant has not been subjected to a prudence review. It is not appropriate to recover capital costs from customers for plant that is not in rate base and has not yet been deemed prudent.

Q. Should Idaho Power have the opportunity to recover prudently incurred BCC expenses?

A. Yes, it is reasonable for Idaho Power to have the opportunity to recover prudently incurred expense. However, the APUC does not currently include a process for reviewing rate base investments. Staff encourages Idaho Power to

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[3] Staff Exhibit 203.
[4] Staff Exhibit 203.
[5] Staff Exhibit 203 Kaufman/20.

work with the Commission to develop an appropriate process for recovering these expenses.

Q. What is the impact of excluding the depreciation expense for post rate case plant additions from power costs?

A. Idaho Power is a one third owner of BCC, and approximately one third of annual BCC depreciation expense is included in this case. BCC has annual depreciation expense of [redacted][6] associated with post rate case plant additions. Idaho Power's share of this is [redacted][7] This adjustment would reduce Idaho Power's system power costs by [redacted][8]

Q. Is there evidence that the depreciable lives of some BCC assets are too short?

A. Yes. One quarter of Idaho Power's recent plant additions are fully depreciated, yet remain in service. This includes a host of freight and passenger trucks. BCC appears to fully depreciate trucks over four years.

Q. Please provide a specific example of plant that is depreciated at too high of a rate.

A. For purposes of BCC charges to Idaho Power, trucks owned by BCC are depreciated over four years. BCC is operated by PacifiCorp. PacifiCorp's most recent depreciation study estimates an average life of 14 years for mining

[6] Staff 203 Kaufman/20.
[7] Staff 203 Kaufman/20.
[8] Staff 203 Kaufman/20.

vehicles.[9] The disparity between BCC's vehicle depreciation rates and the rate indicated by PacifiCorp's depreciation study indicates that it is appropriate to review depreciation expense for all of BCC's plant to determine whether it reasonable.

Q. What do you recommend regarding Bridger Coal Company?

A. Staff recommends that:

1. Depreciation expense associated with BCC plant added after Idaho Power's last rate case be excluded from rates.
2. The Company include BCC assets in subsequent depreciation studies.

[9] Docket No. UM 1329 Initial Application, p. 48.

ISSUE 3. JIM BRIDGER FUEL PLAN

Q. Please provide background on the Jim Bridger Fuel Plan.

A. In 2016, the Commission ordered Jim Bridger owners PacifiCorp and Idaho Power to collaborate with Staff and other parties to develop a long-term fuel plan for Jim Bridger. Staff held two workshops in early 2017 to address the Jim Bridger fuel plan. At those meetings Staff indicated interest in developing the fuel plan concurrently with the utilities' 2017 IRPs to ensure that the plans were consistent. However, Staff and parties were not engaged in the planning process again until January 2018.

Q. What concerns does Staff have regarding the long-term fuel planning process?

A. Staff has the following concerns:

1. Idaho Power did not consider an important option for the near-term coal supply.
2. Long-term options did not inform the selection of the near-term plan.
3. Idaho Power's long-term plan does not appear to consider the differential planning requirements that SB 1547 (2016) places on Idaho Power and PacifiCorp.
4. Idaho Power is engaging in a fixed volume coal contract without evaluating risks associated with having a fixed volume contract.

Q. What near-term coal supply option should Idaho Power have considered?

A. Idaho Power participated in a January 11, 2018, workshop regarding the Jim Bridger Fuel Plan. The workshop presentation is included as Staff Exhibit 204. Page six identifies five options (Options A-E) for a near-term coal contract with Lighthouse Resources for the Black Butte Mine. Discussions at the workshop revealed that Option B represented a potentially least cost option. However, in order to verify that Option B was least cost, Idaho Power also needs a BCC mine plan analysis with a consistent production volume. Page nine identifies the BCC mine plans that were evaluated. These plans are only consistent with bookend tonnage from Black Butte mine. Idaho Power should have developed a mine plan consistent with Option B.

Q. Why does Staff believe that Option B is potentially the least cost option?

A. This determination was made based on confidential information that was provided to Staff outside of this docket. Staff will provide further detail on this determination once the confidential information is part of this docket.

Q. Why should the long-term options inform the selection of the near-term fuel supply?

A. BCC has fixed reserves. The near-term fuel supply will influence whether and when the BCC reserves are depleted. This in turn has implications for the cost and design of the long-term option.

Q. Why does SB 1547 place differential planning requirements on Idaho Power and PacifiCorp?

A. SB 1547 appears to require that PacifiCorp invest in BCC based on an assumed 2030 life. However, Idaho Power may not be subject to the same limitation. The long-term plan is based on an extended life at BCC; therefore the plan is consistent with Idaho Power's planning requirements. However, Idaho Power should consider how it will navigate different planning needs when PacifiCorp begins to plan in compliance with SB 1547.

Q. How did you determine that Idaho Power has not evaluated the risks of a fixed volume coal contract for Jim Bridger?

A. Staff raised concerns about the risks associated with fixed volume coal contracts in the first three workshops. These concerns were not specifically addressed for Jim Bridger in any of the first three workshops. Idaho Power's selection of the highest volume fixed coal contract for Black Butte coal also exposes customers to the greatest level of risk that Jim Bridger coal burn will be less than anticipated. One key difference between Idaho Power modeling of Jim Bridger and PacifiCorp modeling of Jim Bridger is that Idaho Power anticipates and allows for economic shutdowns of Jim Bridger. PacifiCorp's power cost model does not allow for economic shutdowns. The selection of the high fixed volume coal contract is based on PacifiCorp's model, which likely overestimates the future coal burn at Jim Bridger due to the fact that economic shutdowns were not incorporated.

Q. What recommendations do you have regarding these concerns?

A. Idaho Power may have already executed a Lighthouse contract. If so Idaho Power may have lost the opportunity to fuel Jim Bridger using Option B. Staff was informed that mine plans take several months to develop. There is not sufficient time to determine if Option B was indeed the least cost, or what the appropriate adjustment would be in this docket. Staff recommends that the Commission direct Idaho Power to develop a mine plan consistent with Option B. Staff encourages Idaho Power to engage Staff earlier in the planning process to help ensure that potential least cost options are not overlooked.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 333
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

February 12, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, PGE UE 308, IPC UE 314, PGE UE 319, and PAC UE 327. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UE 333
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

February 12, 2018

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update (“APCU”)
Idaho Power Company’s Responses to the Public Utility Commission of Oregon Staff’s Data Request Nos. 8-25

STAFF’S DATA REQUEST NO. 13:

Please explain how the price for BCC coal is set.

IDAHO POWER COMPANY’S RESPONSE TO STAFF’S DATA REQUEST NO. 13:

Pursuant to the long-term coal sales agreement between Idaho Power, PacifiCorp and BCC, most recently approved by the Public Utility Commission of Oregon (“Commission”) in Order No. 91-567, the coal sales price is computed based on BCC’s total projected costs plus an operating margin equal to the revenue requirement on Idaho Energy Resources Company (“IERCo”) rate base from Idaho Power’s most recent general rate case. Idaho Power owns 100 percent of IERCo, which has a one-third joint venture interest in BCC. Ultimately, the coal sales price reflects current costs associated with procuring coal for use at the Bridger plant, including depreciation expense on assets used to extract coal at the mine. The sales price is adjusted periodically throughout the year as actual cost data becomes available. Each time the sales price is adjusted, the parties execute an amendment to the agreement.

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update ("APCU")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's Data Request Nos. 8-25

STAFF'S DATA REQUEST NO. 15:

Please describe IPC's involvement in developing and evaluating the long term coal supply plan for Jim Bridger.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 15:

As an engaged partner in the Bridger plant, Idaho Power has had numerous discussions with PacifiCorp, its ownership partner, about the long term fueling plan ("LTFP") strategy for the Bridger plant. Most recently, Idaho Power participated in the January 11, 2018, LTFP workshop with PacifiCorp, Staff, and other stakeholders. Idaho Power has worked alongside PacifiCorp in developing the LTFP, by providing Idaho Power-specific assumptions including forecast generation based on projected need, and reviewing the key assumptions of the LTFP. Additionally, Idaho Power is in the process of performing its own independent analysis of the present value revenue requirement of the LTFP, as proposed by PacifiCorp.

IDAHO POWER
An IDACORP Company

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update ("APCU")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's Data Request Nos. 8-25

STAFF'S DATA REQUEST NO. 16:

Please explain how IPC recovers return on investment for BCC from Oregon rate payers.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 16:

Idaho Power owns 100 percent of IERCo, which has a one-third joint venture interest in BCC. Idaho Power accounts for IERCo as an equity method investment. Separate records and accounts for IERCo are maintained and the operations of IERCo as a joint venturer in BCC are subject to regulatory review and scrutiny together with those of Idaho Power during general rate cases.

For general rate case revenue requirement determinations, Idaho Power includes its investment in IERCo as a component of utility rate base, and includes as an offset to the utility revenue requirement the test-year IERCo earnings in the form of electric operating income. Coal delivered from BCC to the Bridger plant is priced at the mine's cost plus an operating margin equal to the revenue requirement on IERCo rate base from the most recent general rate case. This pricing approach ensures that the Company does not earn more than its allowed return on its investment in IERCo between rate cases.

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update ("APCU")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's Data Request Nos. 8-25

STAFF'S DATA REQUEST NO. 17:

Please explain how IPC recovers return of investment for BCC from Oregon rate payers.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 17:

Please see the Company's responses to Staff's Data Request Nos. 13 and 16. As noted in those responses, the cost of coal delivered from BCC to the Bridger plant consists of total operating costs for BCC, which includes depreciation expense associated with assets in service at the mine.

IDAHO POWER
An IDACORP Company

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update ("APCU")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's Data Request Nos. 8-25

STAFF'S DATA REQUEST NO. 18:

Please identify all BCC plant that has been approved for IPC rate base by the Oregon Commission and the most recent Oregon rate case which reviewed BCC plant investment.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 18:

Please see the protected information attachment provided with this response that includes actual BCC plant as of December 31, 2010. These amounts were included in the determination of the 13-month average of Idaho Power's share of actual plant in the Company's most recent general rate case ("GRC"), Docket UE 233. BCC plant is included in the investment component of IERCo rate base, which was determined in the last GRC using a 13-month average of Idaho Power's share of actual plant with slight forecast adjustments, as demonstrated in Idaho Power/601, Jones/21, filed in that case.

To provide additional clarification regarding the treatment of BCC-related costs during and after a GRC, BCC is a non-utility entity, and therefore, its assets are treated differently for ratemaking purposes than the Company's standard utility assets. Under traditional ratemaking for standard utility assets, the Company invests in rate base on behalf of customers, then requests approval to collect through rates the cost of its investment and a fair rate of return through a ratemaking proceeding at the Commission.

For general rate case revenue requirement determinations, Idaho Power includes its investment in IERCo, which has a one-third joint venture interest in BCC, as a component of utility rate base. Separate records and accounts for IERCo are maintained and the operations of IERCo as a joint venturer in BCC are subject to regulatory review and scrutiny together with those of Idaho Power during general rate cases.

Because BCC costs (including depreciation expense associated with assets currently in service at the mine) reflect the cost of procuring fuel for the Bridger plant, they have been recognized by the Company and the Commission as fuel expense. It should be noted that the return component reflects the total allowed return from the Company's last GRC, which ensures that customer rates are reflective of the current cost of procuring fuel for the Bridger plant and that the Company's return does not exceed what was allowed in the last GRC. The Commission has recognized and approved BCC costs as fuel expense in Docket Nos. UE 92, UE 167, UE 203, UE 213, UE 214, UE 222, UE 233, UE 242, UE 257, UE 279, UE 293, UE 301, and UE 314.

The attachment produced in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 17-443.

January 24, 2018

Subject: Docket No. UE 333 – 2018 Annual Power Cost Update (“APCU”)
Idaho Power Company’s Responses to the Public Utility Commission of Oregon Staff’s Data Request Nos. 8-25

STAFF’S DATA REQUEST NO. 19:

Please identify all BCC plant that has not been approved for IPC ratebase by the Oregon Commission. Is IPC requesting recovery for return on or return of any portion of this plant as part of the current power cost filing?

IDAHO POWER COMPANY’S RESPONSE TO STAFF’S DATA REQUEST NO. 19:

The protected information attachment provided with this response includes BCC investments that have been added to plant-in-service since Idaho Power’s last GRC. The Company is not recovering a return on plant added since the last GRC, nor is it requesting recovery for the return on this portion of plant as part of the 2018 APCU.

As part of the 2018 APCU, the Company has updated fuel expense, including BCC coal costs, which reflect total projected operating costs and depreciation of assets currently in service at the mine.

Please see the Company’s response to Staff’s Request No. 18 for additional description regarding the Commission-approved ratemaking treatment for BCC-related costs.

The attachment produced in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 17-443.

CASE: UE 333
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

February 12, 2018

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 17-443

CASE: UE 333
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

February 12, 2018

Fueling Plan Workshop #3

January 11, 2018

Redacted

PACIFICORP

Discussion Topics

- Provide Update on “Near Term” Fueling Plan for Jim Bridger Plant
  - Bridger Coal Company Mine Options
  - Lighthouse Resources – Black Butte Mine Negotiations/Proposals
  - Union Pacific Railroad – Negotiations/Proposal

Review Action Items from Prior Workshops

- Evaluate Bridger Coal Company ("BCC") Option D against Option E
  - Develop and provide PVRR financial analysis for these two options
- Provide "Near Term" fueling strategy (2018-2021)
  - Preserve flexibility to assess and implement long term fueling options
  - Negotiate new Black Butte agreement
- Evaluate optimum fueling plan for the Jim Bridger plant

Near Term Fueling Plan For Jim Bridger Plant

- Near Term is represented as four (4) years (2018-2021)
  - * Required capital needed to accommodate large increase in PRB coal requires <u>at least</u> 4 years on an expedited basis
- Evaluated and optimized coal supply mix between coal from BCC & Black Butte Mine
- Two Different Annual Coal Supply Options:
  - — Option 1 – BCC at 4.2m tons & Black Butte Mine at 1.8m tons
  - — Option 2 – BCC at 3.75m tons & Black Butte Mine at 2.25m tons
- The two different options were premised upon:
  - — Different tonnage proposals from Lighthouse Resources Inc. (Black Butte Mine) which provided the “bookends” to evaluate the supply options

- Option D (Preferred option from March 2017 workshop)
  - (Underground closes [redacted] Surface closes [redacted])
    - Deadman Wash coal reserves are permitted and mined
- Option E
  - (Both Underground & Surface mine close [redacted])
  - Assumes PRB Coal Conversion
- Developed new Option F
  - (Underground closes [redacted] Surface Mine closes [redacted])
    - Deadman Wash reserves are not permitted or mined
    - Will evaluate multiple fuel sources post [redacted]
- New BCC mine annual production level has been developed and evaluated at 3.75m tons

Lighthouse Resources Inc. Proposals

- Negotiations began in early 2017
- Lighthouse provided five (5) options
  - Option A – 2018-2021 (≈4yrs – 2.250m tons/yr – total 8.250m tons) 2018=x
  - Option B – 2018-2021 (4yrs – 2.000m tons/yr – total 7.250m tons) 2018 (x[redacted])
  - Option C – 2018-2020 (3yrs – 2.000m tons/yr – total 6.000m tons) 2018 (x[redacted])
  - Option D – 2018-2020 (3yrs – 1.800m tons/yr – total 5.400m tons) 2018 (x[redacted])
  - Option E – 2018-2020 (3yrs – 2.250m tons/yr – total 6.750m tons) 2018 (x[redacted])
- 2018 Tonnage Volumes are reduced by 757,800 deferred tons (carryover tonnage from prior contract)

Lighthouse Resources Inc. Proposals continued

- Selected Option
  - Option A – 2018-2021 (≈4yrs – 2.250m tons/year – total 8.250m tons)
- Contract Term:
  - May 1, 2018 – December 31, 2021 (44 months)
  - Buyer's option to extend four (4) additional months (thru-April 2022) to take CY 2021 coal, if needed
- Coal Quality
  - Same as prior contract

Union Pacific Proposal

- Negotiations began in early 2017
  - Contract Term: 2018-2021 (4 Years)
  - Tonnage
    - Annual Minimum is 2.0m tons
    - Annual Maximum is 4.0m tons
  - Obtained rail rates from different coal regions
    - Black Butte Mine
    - Kemmerer Mine
    - PRB Mines
    - Colorado – Twenty-Mile Mine
  - Rates
    - Black Butte - Minimal Rate Increase over 2017 average rate ([redacted])
  - Train Size
    - Black Butte - Flexible unit train size ranging from 71-120 cars

Options Supply/Tonnage Assumptions

- Option 1 (BCC at 4.2m tons; BB at 1.8m tons*)
  - PacifiCorp share (BCC at 2.8m tons; BB at 1.5m tons)
- Option 2 (BCC at 3.75m tons; BB at 2.25m tons)
  - PacifiCorp share (BCC at 2.5m tons; BB at 1.8m tons)

* Black Butte 1.8m ton option is for 3 years only

[redacted]

[redacted] [redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

Calculation of Estimated Price Savings Related to Option 2

$/MMBtu Delivered Variance	$	[redacted]
Multiplied by Option 1 MMBtus	$	[redacted]
PacifiCorp Price Savings from Option 2	$	[redacted]

PacifiCorp “Deliverables” to be included in the Long Term Fueling Plan delivered in March 2018

- Long Term Fueling Plan will include:
  - Updated BCC mine costs
  - Updated Third Party – Burns & McDonnell’s plant capital requirements study
  - Coal inventory level risk mitigation study by Runge Pincock Minarco
  - Updated U.P. long term “indicative” rail rates/contract rates
  - Updated long term third party coal pricing
  - PVRR analysis evaluating least cost/least risk options
  - BCC’s final reclamation cost review – this is ongoing
  - Compare Options D, E, and F from slide 5

Questions

CASE: UE 333
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

February 12, 2018

Q. Please state your name, occupation, and business address.

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is your role in relation to the 2018 Idaho Power 2018 Annual Power Cost Update (APCU)?

A. I was assigned to review the accounting data in Federal Energy Regulatory Commission ("FERC") accounts for the April 2016 – March 2017 Power Cost base year: fuel expense (FERC Accounts 501 and 547), purchased power expenses (FERC Account 555), surplus sales revenues (FERC Account 447), transmission of electricity by others / wheeling expenses (FERC Account 565).

Q. Did you obtain additional information from Idaho Power?

A. Yes, we received transaction level accounting detail from the Company in the confidential responses to Staff Data Request No. 1.

Q. What period of time was included in the accounting detail?

A. We reviewed transactions for the period of time corresponding to the base year for the APCU, April 2016 through March 2017.

Q. In general, what are the results of your review?

A. In general, Staff finds the costs recorded in these accounts to be consistent with the definitions found in the Code of Federal Regulations, Title 18, Chapter

1, Subchapter C, Part 101 – Uniform system of accounts prescribed for public utilities and licensees subject to the provisions of the Federal Power Act.

Q. Did you notice anything unusual?

A. Yes, the base year fuel costs for the Jim Bridger Plant include a $6.3 million charge for the Joy Longwall mining accident. The circumstances surrounding this incident have been recently vetted in Commission Order No. 17-444. A corresponding charge of $12.6 million has been recorded by PacifiCorp reflecting the respective ownership interests in the Bridger Coal Company.

Q. Did you confirm this cost is not included in the 2018 APCU forecast?

A. Yes, the Company's response to Staff Data Request No. 33 confirms this cost is not included.

Q. Did you notice anything else unusual?

A. Yes, further analysis of FERC account 565 Transmission indicates, for most transactions, a cost between $1 and $2 per MWh. However, there are some higher and lower amounts.

Q. Did you inquire about these amounts?

A. Yes, we issued Staff Data Request No. 41. The Company cited several reasons that transmission costs would be higher or lower including; resales of purchased transmission capacity, variances in Open Access Transmission Tariff ("OATT") rates, and the Joint Ownership and Operating Agreements with PacifiCorp and Bonneville Power Administration.

Q. Did you perform any additional power cost analysis?

A. Yes, I compared the power plant output and cost per MWh as reported on the Company's 2015 and 2016 FERC Form 1 to the modeled results in the 2018 APCU forecast.

Q. How did you obtain the FERC Form 1?

A. The forms are filed by the Company annually pursuant to Docket No. RE 78. The forms for 2015 and 2016 were filed as RE 78(4) and RE 78(5), respectively.

Q. Did you prepare an exhibit showing the comparison?

A. Yes, the results of my analysis are attached as Exhibit Staff/302.

Q. Are the FERC Form 1 results directly comparable to the APCU model?

A. No, the FERC forms are prepared on a calendar year basis and the model year is April through March.

Q. What is the purpose of the comparison then?

A. The FERC forms are filed after the annual financial results for the Company are known and audited. Therefore, they provide a convenient way to compare known results for a 12 month period independent of the APCU and PCAM process.

Q. Why did you choose 2015 and 2016 years for comparison?

A. The annual FERC Form 1 are customarily available and filed with the Commission around May 1 of each year. 2016 is the most recent year available. We added another year to determine if the results were similar.

Q. In general, what is the result of your analysis?

A. Exhibit Staff/302 shows actual plant usage and cost per MWh vary significantly from the optimized values in the model.

Q. Have you considered potential explanations for the variances such as weather, operational, or market conditions?

A. Yes, we issued Staff Data Requests No. 39 and 40. The Company's response cited several reasons for the variance in plant output.

- A reduction in hydropower generation due to warm winter weather resulting in lower than average streamflow conditions,
- Higher than average precipitation during the irrigation season, and
- Slightly higher than normal summer temperatures.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 333
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

February 12, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	John L. Fox
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010). I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.
EXPERIENCE:	From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work. I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead. I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.

CASE: UE 333
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 302

Exhibits in Support Of Opening Testimony

February 12, 2018

STAFF EXHIBIT 302

IS EXCEL SPREADSHEET

(Provided in electronic format)

Steam Power Plant Costs

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line		2015 FERC Form 1			2016 FERC Form 1					
		Output KWh	Cost	Per KWh	Output KWh	Cost	Per KWh			
1	Jim Bridger	4,096,050,000	$ 145,941,847	$ 0.0356	3,671,656,000	$ 152,278,587	$ 0.0415			
2	Boardman	182,941,000	$ 8,638,503	$ 0.0472	134,253,000	$ 7,044,131	$ 0.0525			
3	Valmy	249,740,000	$ 23,358,414	$ 0.0935	239,264,000	$ 25,743,638	$ 0.1076			
4	Danskin	255,025,000	$ 11,156,089	$ 0.0437	198,102,000	$ 9,724,917	$ 0.0491			
5	Bennett Mountain	157,875,000	$ 7,085,015	$ 0.0449	103,240,000	$ 4,432,877	$ 0.0429			
6	Langley Gulch	1,662,770,000	$ 44,307,662	$ 0.0266	1,420,178,000	$ 36,343,265	$ 0.0256			
		2015 FERC Form 1			2016 FERC Form 1			2018 APCU Exhibit 101-NPSE		
		Output MWh	Cost	Per MWh	Output MWh	Cost	Per MWh	Output MWh	Cost	Per MWh
7	Jim Bridger	4,096,050	$ 145,941,847	$ 35.63	3,671,656	$ 152,278,587	$ 41.47	1,300,534	$ 48,822,400	$ 37.54
8	Boardman	182,941	$ 8,638,503	$ 47.22	134,253	$ 7,044,131	$ 52.47	251,299	$ 7,499,400	$ 29.84
9	Valmy	249,740	$ 23,358,414	$ 93.53	239,264	$ 25,743,638	$ 107.60	529,909	$ 21,297,800	$ 40.19
10	Danskin	255,025	$ 11,156,089	$ 43.75	198,102	$ 9,724,917	$ 49.09	447,938	$ 13,025,900	$ 29.08
11	Bennett Mountain	157,875	$ 7,085,015	$ 44.88	103,240	$ 4,432,877	$ 42.94	271,316	$ 7,810,300	$ 28.79
12	Langley Gulch	1,662,770	$ 44,307,662	$ 26.65	1,420,178	$ 36,343,265	$ 25.59	2,275,787	$ 44,113,100	$ 19.38

CASE: UE 333
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

February 12, 2018

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a senior utility analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I discuss Idaho Power Company's proposal to include costs and benefits of its participation in the Energy Imbalance Market in its net power supply expense (NPSE) for the 2018 October Update portion of its Automatic Power Cost Update (APCU).

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/402, which is a study of potential EIM benefits by Energy + Environmental Economics (E3).

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ENERGY IMBALANCE MARKET

Q. What is the Energy Imbalance Market?

A. The Energy Imbalance Market (EIM) is an automated dispatch system that allows for efficient balancing of load and generation. Generation and load must be balanced within strict parameters at all times in order for the electric grid to remain stable. A large sustained imbalance between generation and load will cause both voltage and frequency instability on the grid. This balancing and coordination of generation assets is performed on several time scales, starting from months or weeks ahead with generation unit planning, to next-day planning, and then to real-time balancing. The EIM allows for very efficient and automated re-dispatch of generators to precisely and continuously meet load in a sliding, five-minute window.

Q. Who participates in the EIM?

A. The EIM was established by the California Independent System Operator (CAISO) on November 1, 2014, with PacifiCorp as the first external participant. NV Energy in Nevada joined on December 1, 2015. Puget Sound Energy and Arizona Public Service joined in October 2016. Portland General Electric joined in October 2017. Idaho Power plans to join the EIM beginning April 1, 2018.

Q. Please explain how Idaho Power proposes to include EIM costs and benefits in the 2018 APCU.

A. Idaho Power has proposed to include all incremental costs associated with the entrance into the EIM market. This includes start-up expenses, software integration, metering investments, labor expenses, and software fees. The revenue requirement associated with the incremental EIM costs is $81,520 on an Oregon-allocated basis, or roughly $1.6 million on a total company basis. As a forecast of benefits, Idaho Power is proposing to match the benefits to costs, which would result in a $0 impact to NPSE.

Q. Why did Idaho Power propose to match benefits to costs rather than include independent forecasts of costs and benefits?

A. The Company states that without historical experience there is uncertainty surrounding the amount of benefits that may be realized without any historical experience. Further Idaho Power states that this treatment mirrors the Commission-approved way in which both Portland General Electric (PGE) and PacifiCorp forecast their benefits in the first year of EIM participation.

Q. Does Staff have concerns regarding Idaho Power's projected level of benefits?

A. Yes. As a voluntary program designed to improve efficiency and lower costs, a base assumption should be that participation in the EIM will provide a net benefit to customers. And here, there is evidence to support such an assumption. Idaho Power commissioned a study of EIM benefits in February 2016 from Energy + Environmental Economics (E3). In that study, E3 forecast 2020 sub-hourly dispatch cost savings of $4.5 million for the Company.[1] Notably, the $4.5 million of savings in the E3 study do not include flexibility reserve savings that the other two regulated utility companies include in their

[1] Staff/402; E3 Study.

EIM-based power cost forecast adjustments. These amounts range from $3.1 million in benefits for PacifiCorp to $1 million for PGE.[2] Adding the more conservative amount of $1 million to Idaho Power's benefit forecast results in roughly $5.5 million in EIM benefits.

Q. Does Staff's concern regarding Idaho Power's projection of EIM participation benefits affect its recommendation regarding the treatment of EIM costs and benefits in the APCU?

A. Yes. Staff acknowledges that PacifiCorp's and PGE's forecasts of net variable power costs included projections of first-year benefits and costs of EIM participation that netted to zero. However, there is a timing difference between Idaho Power and the other utilities that means the potential for harm to customers if Idaho Power over-recovers for EIM costs is greater than it was for PGE and PacifiCorp.

Q. Please explain Staff's concern regarding the timing of Idaho Power's EIM participation.

A. Staff's concerns relate to (1) the potential that the deadband applied to any NPSE true-up in Idaho Power's Power Cost Adjustment Mechanism (PCAM) will absorb net benefits associated with EIM and (2) the magnitude of the benefits at issue. Idaho Power plans to start participating in the EIM in April 2018. The test year for the APCU is April 1 through March 31. Accordingly, the costs and benefits at issue are for a full year of participation in the EIM. If Idaho Power receives significantly more benefits from EIM participation than it

[2] See UE 319/PGE/300, Niman et al/9 and UE 323/PAC/100, Wilding/25.

currently projects, there is potential for Idaho Power to over-recover for its power costs for the April through March period. Although there is a retroactive true-up to capture the variance between projected NPSE and actual NPSE though the PCAM, Idaho Power has the opportunity to keep excess NPSE up to the deadband established by the Commission.

In contrast, PacifiCorp and PGE joined the EIM in the last quarter of the test year used for their power cost recovery mechanisms. Accordingly, the costs and benefits at issue were less for these two utilities than for Idaho Power. While it was still possible that net benefits from EIM participation would be absorbed by deadbands applied in PacifiCorp's and PGE's power cost recovery mechanisms, the relative magnitude of the benefits lost to customers would be significantly less for PGE and PacifiCorp customers than it would be for Idaho Power's customers.

Q. Does Staff have any other concerns with Idaho Power's proposed treatment of EIM costs and benefits?

A. Yes. Staff also objects to Idaho Power's inclusion of recovery of capital costs and return on capital investments in the APCU. The APCU is designed for recovery of NPSE, not capital costs. Under standard ratemaking procedure in Oregon, capital investments are reviewed for prudence during general rate case proceedings. In general rate proceedings, the utility's rate base is reviewed as a whole to make sure plant that is fully depreciated is removed. Idaho Power proposes to selectively include new investments in rate base without any chance for removing investment that is fully depreciated, which is not appropriate.

In addition, the APCU has an accelerated schedule and is designed so that parties and the Commission need only review relatively few specific inputs and specific modeling. This accelerated process is not the appropriate mechanism to review the prudence of new investment.

Q. What are Staff recommendations for EIM benefits and costs?

A. First, Staff recommends that benefits and non-capital costs for the first year of Idaho Power's participation in the EIM be subject to recovery outside the APCU through deferred accounting and amortization. Any potential refund or charge would still be subject to an earnings test under ORS 757.259(5), but would not be absorbed in the PCAM's deadband. This treatment would account for the uncertainty in the benefits, but still ensure that customers receive an appropriate share of whatever net benefits (costs) are realized. The earnings review that is required before any deferred amounts amortized could protect the Company in that it would not have to pass along the EIM benefits if its earnings are not sufficient.

Second, Staff recommends that the Commission reject Idaho Power's proposal to include recovery of and return on capital investments as part of its recovery of NPSE. As Staff has described, the APCU is not the intended forum to review new investments for prudence. And, Staff's proposed deferral is also not an appropriate mechanism because it would result in the inclusion of a discrete capital investment with no review of the entire rate base.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 333
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

February 12, 2018

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon
Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 333
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

February 12, 2018

An IDACORP Company

Idaho Power Company
Energy Imbalance Market Analysis

February 2016

Energy+Environmental Economics

PLEXOS®
Integrated Energy Model

Idaho Power Company Energy Imbalance Market Analysis

February 2016

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Prepared For:
Idaho Power Company

Prepared By:
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Energy and Environmental Economics, Inc. (E3)

Tao Guo, Guangjuan Liu, and Yannick Degeilh
Energy Exemplar

Table of Contents

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.

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.

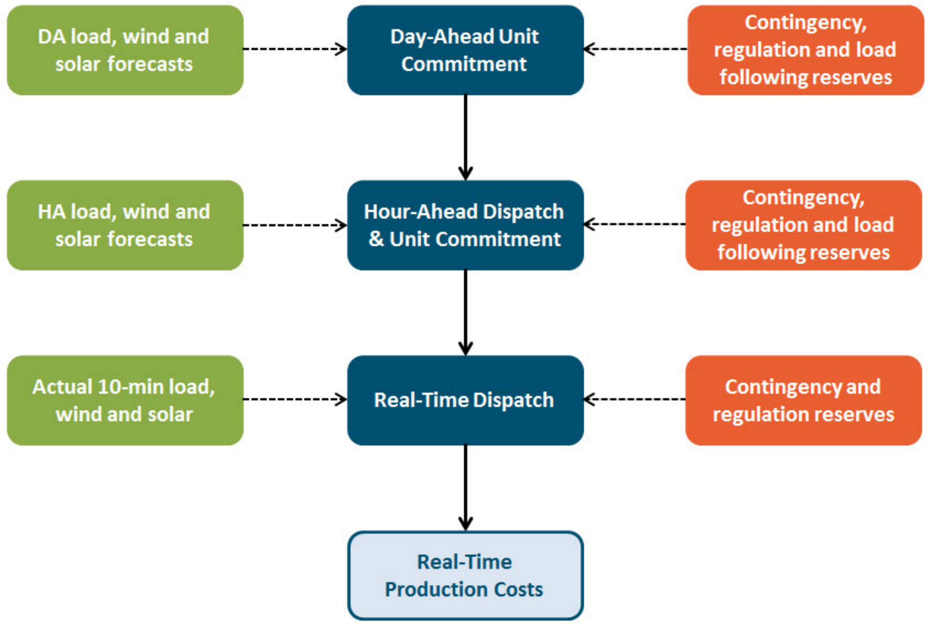
This study does not quantify savings associated with flexibility reserve reductions. Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; 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 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.

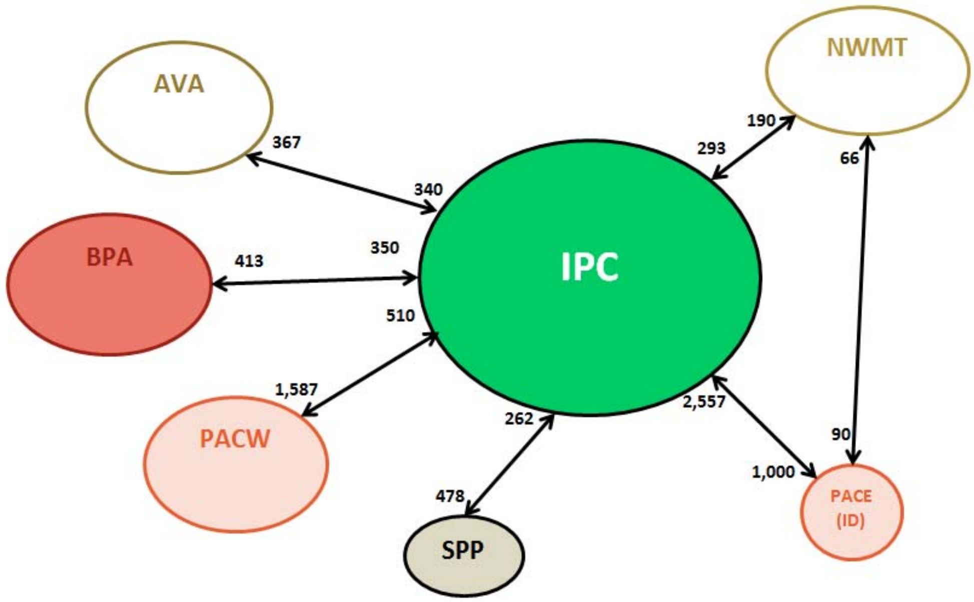
2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

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.

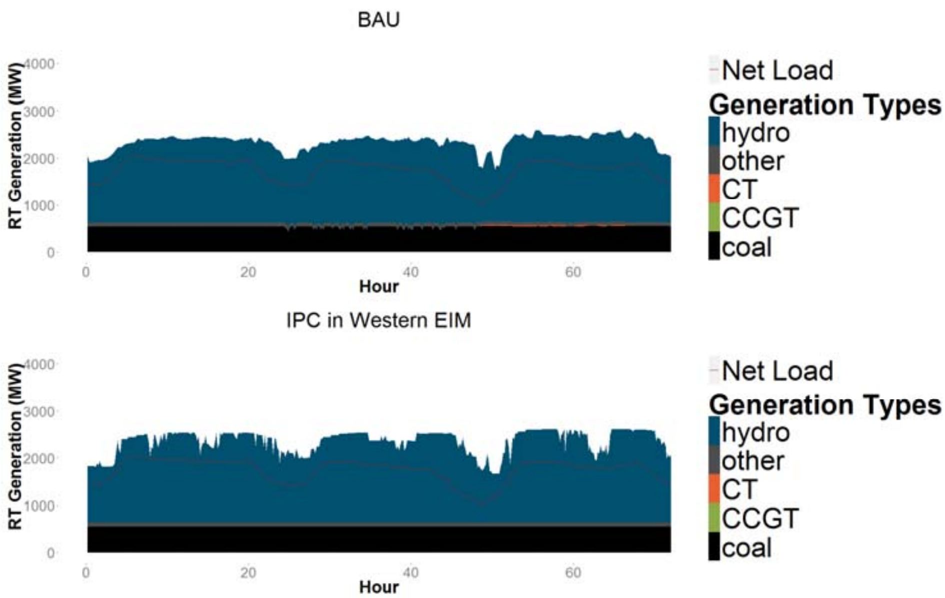
3.3 EIM Results Discussion

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.