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February 4, 2019

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 350 – In the Matter of IDAHO POWER COMPANY, 2019 Annual Power Cost Update.

Attached for filing are the following documents for Staff Opening Testimony:

Exhibit 100 - 103
Exhibit 200 - page 9 is confidential
Exhibit 201 - 202
Exhibit - 203 is confidential/work paper

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
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CASE: UE 350
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

February 4, 2019

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

A. My name is Scott Gibbens. 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/101.

Q. What is the purpose of your testimony?

A. I discuss Idaho Power Company's proposal to estimate benefits of its participation in the Energy Imbalance Market in its net power supply expense (NPSE) for the 2019 October Update portion of its Automatic Power Cost Update (APCU). I will also discuss Staff's review of Idaho Power's compliance with previous Commission orders regarding Oil, Handling, Administrative & General (OHAG), and Rate Spread. Finally, I discuss Staff's review of the load forecast, natural gas price forecast update, and other general updates.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

102: Company's response to Staff DR No. 7
103: CAISO EIM Quarterly Reports, Q2, Q3, Q4 2018

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: EIM BENEFITS

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. Idaho Power's power cost model, AURORA, does not consider EIM operations in its estimation of power costs. When Idaho Power imports or exports energy via the EIM, it is receiving a benefit beyond what AURORA would forecast. When importing power, it will reduce costs because a more expensive utility-owned unit will not have to run. When the Company exports power into the EIM, it will provide a benefit because the market-clearing price is above the cost to run a particular utility-owned unit.

Q. Who participates in the EIM?

A. The EIM was established by the California Independent System Operator (CAISO) on November 1, 2014, with PacifiCorp (PAC) as the first external participant. NV Energy in Nevada joined on December 1, 2015. Puget Sound Energy (PSE) and Arizona Public Service (APS) joined in October 2016.

Portland General Electric (PGE) joined in October 2017. Idaho Power and Powerex began participating in the EIM beginning April 1, 2018.

Q. What is Idaho Power's current proposal for EIM benefits?

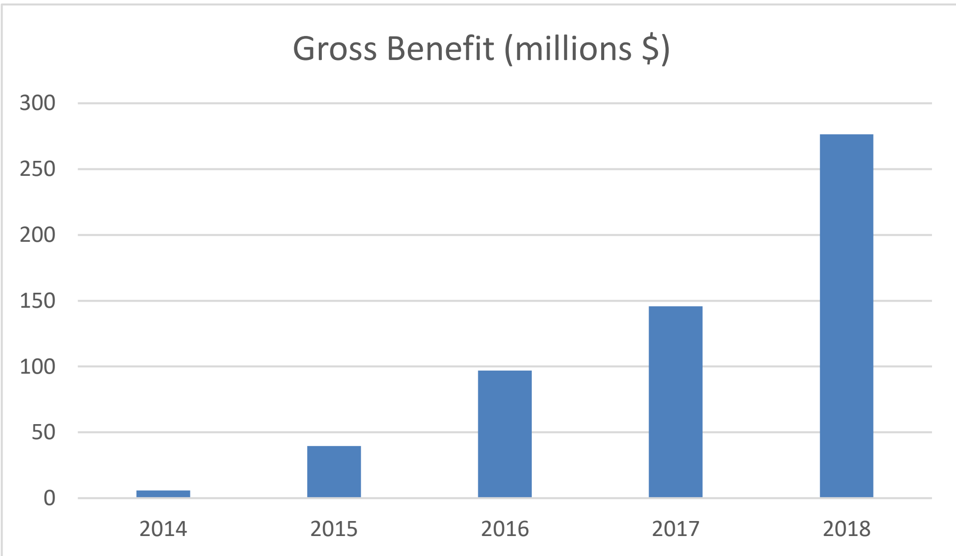
A. Idaho Power proposes to continue to utilize an estimate of benefits equal to that of the February 2016 Energy + Environmental Economics (E3) study of $4.5 Million or roughly $225,000 on an Oregon allocated basis.[1] Although Idaho Power is currently participating in the EIM and receiving benefits from the market, it argues that it does not have a reliable manner in which to estimate benefits based on actual operations.[2] As such, Idaho Power has chosen not to include actuals as part of the benefits estimate at this time.[3] During the January 22, 2019 technical conference, the Company indicated that it hopes to have an updated methodology in place soon, which would inform an updated benefit methodology to be proposed for the March forecast.

Q. Does Staff have concerns with this proposal?

A. Yes. First, as Staff noted in its opening testimony in UE 333, the E3 study did not attempt to quantify the benefit the EIM provides through reduction of the flexible reserve requirements.[4] This benefit is the result of optimizing balancing requirements over a larger footprint through the EIM. For PGE and PacifiCorp, this amount varies. In Idaho Power's 2018 APCU, the stipulating parties agreed to estimate this benefit at $1 million, which was adopted by the Commission.[5]

[1] Idaho Power/100, Blackwell/15.
[2] *Ibid.*
[3] *Ibid.*
[4] Gibbens/102.
[5] Order No. 18-170, p. 6.

Second, the E3 study is becoming increasingly outdated, as it was published in February 2016. At that time, NV Energy was 60 days into participating in the EIM with the only other participants being CAISO and PacifiCorp. Since that time, five other entities have joined the EIM. Below is a chart that shows the annual benefits of the Western EIM over time.



As evidenced by Figure 1, approximately 92 percent of the total benefits realized to date were reported after the completion of the E3 study. This means that while the E3 study performed the estimate as well as could be expected given the information at the time, much more information is available now.

Third, while the Company may have concerns regarding the methodology used by CAISO to estimate the benefits for each participant, it has not been able to quantify the amount of the overestimation to date.[6] An annualized estimate of the CASIO calculated benefit for Idaho Power is over $35.8 million,

[6] Idaho Power/100, Blackwell/15.

or almost eight times larger than the E3 study.[7] On an Oregon-allocated basis, this amounts to $1.8 million, compared to the $225,000 being proposed by the company. In the three quarters since Idaho Power began operations in the EIM, CAISO's methodology estimates the Company has realized almost $27 million on a total company basis.[8] Staff finds that Idaho Power's concerns regarding a methodology that addresses the level of hydro in its system are valid, but the Company has been unable to demonstrate that the CAISO methodology is overestimating actual benefits by such a massive amount such that reliance on the outdated E3 study is appropriate. For instance, the CAISO methodology should result in overestimation of benefits on imports from the EIM, but also underestimation of benefits from exports of hydro-based resources. This is because CAISO's method would be overestimating the true cost of hydro because the bid price does not match the incremental cost. Idaho Power currently has imported more power (54 percent) than exported (46 percent), but the difference is small. With only an eight percent difference, it does not seem plausible that the hydro issue could account for the discrepancy. To illustrate this, assume that hydro resources are just as likely to be involved in an import benefit calculation error (displacee) as they are in an export benefit calculation error (displacer) and the magnitude (bid price) is the same on average. Then the CAISO hydro issue would need to be $404/MWh in order for the E3 study to comport with the CAISO estimate. Or in other words,

[7] Gibbens/103. Alternatively see: https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[8] *Ibid*.

Idaho Power would need to bid the price of hydro in at an average of over $400/MWh. Staff is concerned that a dated E3 study is just as likely to be underestimating benefits as the CAISO methodology is to overestimate actuals.

Finally, Staff is concerned regarding the amount of time available to review Idaho Power's updated methodology if it is filed on March 22, 2019. Two and a half weeks is a limited amount of time to review the intricacies of a program that handles such vast amounts of data.

Q. What is Staff's recommendation regarding EIM benefit estimation?

A. Due to the fact that the Company has indicated it anticipates updating the estimate with a new methodology, Staff will not make a recommendation until it its next round of testimony. Should the Company be unable to complete the updated methodology, Staff recommends that the Company work to incorporate the CAISO benefit estimation in some manner into its APCU estimate. By taking random subsets of transactions, the Company could get a sense of the overestimation present in the CAISO methodology, and use that to discount the total CAISO benefit. This interim solution would still rely on actual and current data, which Staff views as an improvement over the E3 study.

ISSUE 2: OIL, HANDLING, ADMINISTRATIVE AND GENERAL

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.[9] Actual OHAG expenses vary depending on overall production at each plant.

In Docket Nos. UE 301 and UE 314, which are 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.[10] 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.

[9] UE 301 - Idaho Power/100, Blackwell/6.
[10] 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.[11]

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 methodologies set forth in UE 314 and UE 301.

Q. Does Staff agree with Idaho Power's calculation of OHAG in the 2019 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.

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

ISSUE 3: 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.[12] This treatment was agreed to based on concerns that Idaho Power's previous incremental mechanism did 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 were driving load growth, Idaho Power's methodology may have been over- or under-collected in rates. The incremental mechanism did not account for the fact that each service schedule has a different power cost rate and a different load growth rate.

In Idaho Power's 2018 APCU, Idaho Power testified in its Opening Testimony that it used the total cost allocation method, and also filed workpapers summarizing the calculations. After review of the methodology, Staff felt that the calculation did not comply with Commission Order No. 17-165. In the subsequent stipulation in that case, all parties agreed to a more clearly defined rate spread methodology with a glide path to protect against rate shock to any one schedule. Commission Order No. 18-170 states:

> Idaho Power will adopt a modified rate spread methodology. Under the proposed modified methodology, the Oregon jurisdictional share of total

[12] *Id. At p.3*.

NPSE, instead of the Oregon jurisdictional share of incremental NPSE, will be allocated to individual customer classes on the basis of normalized jurisdictional forecasted sales at the generation level for the forecast April through March test period. Any rate increases resulting from the application of this methodology as applied to a customer class will be limited to three percent above the overall average rate increase on a percentage of total revenue basis.[13]

Q. Does Staff have concerns with Idaho Power's application of the total cost method in the 2019 APCU?

A. No. Staff found no issues with the calculations. Idaho Power has correctly implemented the total cost method, which will ensure no over/under recovery of power costs. Further they have correctly limited the percent increases of schedules 19T and 42.

[13] Order No. 18-170, p. 5.

ISSUE 4. LOAD FORECAST

Q. Please describe changes to the Company's load forecast since its October 2017 update.

A. The Company's normalized system load decreased by 1%, or 21 aMW between its last years' October forecast. It currently anticipates a load of 1,833 aMW.[14]

Q. What is driving the decrease in load?

A. Based on Staff's analysis of the Company's model outputs, the decrease in load is primarily due to lower coal-fired generation. Coal fired generation has been replaced by lower cost natural gas generation.

Q. How has PURPA generation impacted the load forecast?

A. PURPA generation is a must-take resource, and it has increased since the last update. This has partially offset the decrease in load forecast generated from lower cost natural gas generation.

Q. Please summarize your analysis of whether the Company's methodology is in compliance with Order No. 08-238.

A. The Company has complied with Order No. 08-238 in terms of its analysis to determine the NPSE for the 2019 October Update. The Company adequately explained the factors driving the decrease in load, and provided workpapers and data to support its modeling.

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[14] Idaho Power/100, Blackwell/10.

ISSUE 5. NATURAL GAS PRICE FORECAST

Q. How does the natural gas price forecast for the 2019 October update compare to prior years' update?

A. The Henry Hub price used for the October 2018 update was $3.18 per MMBtu, and $3.14 per MMBtu in 2019. This is a 2 percent decrease ($0.05).[15]

Q. Has the Company's model inputs for determining natural gas price forecasts changed?

A. Yes. The current update uses multiple natural gas forecast data points and it uses an average price for determining a normalized price. The methodology was approved in Docket Nos. UE 314 and UE 333.[16] The Company has also added an additional forecast data point, the S&P Global Platts ("Platts"), which was recently made available in the 2019 IRP process, and recommended by Staff and Stakeholders.[17]

Q. Please summarize Staff's analysis of the natural gas forecast price forecast.

A. Staff has analyzed the data and remarks that the use of the Platts forecast in addition to those approved in UE 314 and UE 344 provides a more robust natural price forecast than prior years.

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[15] Idaho Power/100, Blackwell/8-9.
[16] Idaho Power/100, Blackwell/9.
[17] *Ibid.*

ISSUE 6. OTHER UPDATES

Q. Did Staff identify any other changes to the Company's models since the October 2018 update?

A. Yes. The Company updated the maintenance rates, forced outage rates, and heat rates for its thermal plants.

Q. Please describe your analysis of the changes.

A. These changes are a consistent practice for every APCU filing.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 350
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

February 4, 2019

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 350
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

February 4, 2019

IDAHO POWER®
An IDACORP Company

January 10, 2019

Subject: Docket No. UE 350 – 2019 Annual Power Cost Update (“APCU”)
Idaho Power Company’s **REDACTED** Responses to the Public Utility Commission of Oregon Staff’s Data Request Nos. 1-8

STAFF’S DATA REQUEST NO. 7:

Is it the Company’s understanding that the E3 Study used as a basis for the EIM benefit estimate includes flexible reserve savings?

IDAHO POWER COMPANY’S RESPONSE TO STAFF’S DATA REQUEST NO. 7:

No. The E3 study does not include flexible reserve savings because these savings are difficult to quantify. As noted in the E3 study, “The study does not estimate savings to [Idaho Power Company] or other EIM participants arising from flexibility reserve reductions due to load and variable resource diversity across the footprint.”

CASE: UE 350
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

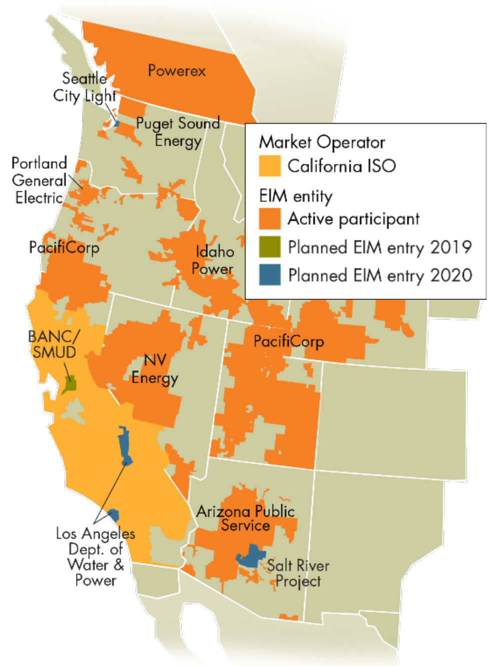
February 4, 2019

WESTERN EIM BENEFITS REPORT

Second Quarter **2018**

July 31, 2018

CONTENTS



EXECUTIVE SUMMARY

Gross benefits from EIM since November 2014

$401.73 million

This report presents the benefits associated with participation in the western Energy Imbalance Market (EIM) for the second quarter of 2018. The benefits include cost savings and the use of surplus renewable energy.

The report shows that EIM is helping to displace less-clean energy supplies with surplus renewable energy that otherwise may have been curtailed.

This analysis demonstrates the real-time market's ability to select the most economic resources across the EIM footprint.

Q2 2018 Gross Benefits by Participant

	(millions $)
Arizona Public Service	$8.59
California ISO	$27.93
Idaho Power	$7.75
NV Energy	$5.34
PacifiCorp	$11.67
Portland General Electric	$5.34
Powerex	$2.27
Puget Sound Energy	$2.32
Total	**$71.21**

*EIM Quarterly Benefit Report Methodology, https://www.caiso.com/Documents/EIM_BenefitMethodology.pdf

**The GHG emission reduction reported is associated with the avoided curtailment only. The current market process and counterfactual methodology cannot differentiate the GHG emissions resulting from serving ISO load via the EIM versus dispatch that would have occurred external to the ISO without the EIM. For more details, see http://www.caiso.com/Documents/GreenhouseGasEmissionsTrackingReport-FrequentlyAskedQuestions.pdf

2018 Q2 BENEFITS

ECONOMICAL

$71.21M

Gross benefits realized due to more efficient inter-and intra-regional dispatch in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD)*

ENVIRONMENTAL

55,267

Metric tons of CO_2** avoided curtailments

OPERATIONAL

46%

Average reduction in flexibility reserves across the footprint

BACKGROUND

The EIM began financially binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs. NV Energy began participating in December 2015, Arizona Public Service and Puget Sound Energy began operations October 1, 2016, and Portland General Electric began participation on October 1, 2017. Most recently, Idaho Power and Powerex began participation on April 4, 2018. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and extends to the border with Canada. The EIM facilitates renewable resource integration and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region.

The ISO began publishing quarterly EIM benefit reports in January 2015. Prior reports can be accessed at https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

The benefits quantified in this report fall into three main categories and were described in earlier studies:[1]

EIM BENEFITS IN Q2 2018

Table 1 shows the estimated EIM gross benefits by each region per month. The monthly savings presented in the table show $26.34 million for April, $25.18 million for May, and $19.69 million for June with a total estimated benefit of $71.21 million.

The EIM benefits reported here are calculated based on available data. Intervals without complete data are excluded in the calculation. The intervals excluded due to unavailable data are normally within a few percent of the total intervals.

Region	April	May	June	Total
APS	$3.63	$2.95	$2.01	$8.59
PWRX	$0.89	$0.77	$0.61	$2.27
ISO	$9.73	$9.99	$8.21	$27.93
IPCO	$2.57	$2.54	$2.64	$7.75
NV Energy	$2.55	$1.98	$0.81	$5.34
PacifiCorp	$4.43	$4.58	$2.66	$11.67
PGE	$1.48	$1.79	$2.07	$5.34
PSE	$1.06	$0.58	$0.68	$2.32
Total	**$26.34**	**$25.18**	**$19.69**	**$71.21**

TABLE 1: Second quarter 2018 benefits in millions USD by month

[1] PacifiCorp-ISO, Energy Imbalance Market Benefits, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

INTER-REGIONAL TRANSFERS

A significant contributor to EIM benefits is transfers across balancing areas, providing access to lower cost supply, while factoring in the cost of compliance with greenhouse gas (GHG) emissions regulations when energy is transferred into the ISO. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the Fifteen-Minute Market and Real-Time Dispatch (RTD).

Generally, transfer limits are based on transmission and interchange rights that participating balancing authority areas make available to the EIM, with the exception of the PacifiCorp West (PACW)-ISO transfer limit and the Portland General Electric (PGE)-ISO transfer limit in RTD. These RTD transfer capacities between PACW/PGE and the ISO are determined based on the allocated dynamic transfer capability driven by system operating conditions. This report does not quantify a BAA's opportunity cost that the utility considered when using its transfer rights for the EIM.

Table 2 provides the 15-minute and 5-minute EIM transfer volumes with base schedule transfers excluded. The EIM entities submit inter-BAA transfers in their base schedules. The benefits quantified in this report are only attributable to the transfers that occurred through the EIM. The benefits do not include any transfers attributed to transfers submitted in the base schedules that are scheduled prior to the start of the EIM.

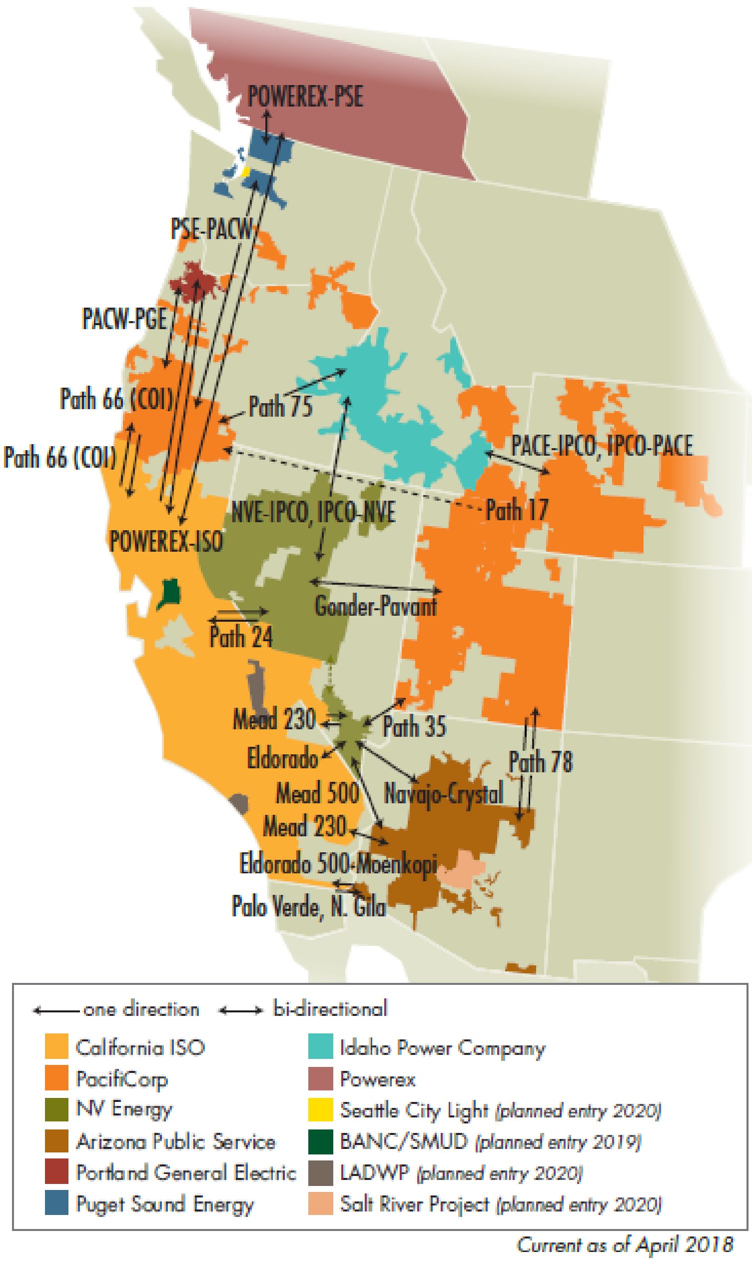
The transfer from BAA_x to BAA_y and the transfer from BAA_y to BAA_x are separately reported. For example, if there is a 100 MWh transfer during a 5-minute interval, in addition to a base transfer from ISO to NVE, it will be reported as 100 MWh from_BAA ISO to_BAA NEVP, and 0 MWh from_BAA NEVP to_BAA ISO in the opposite direction. The 15-minute transfer volume is the result of optimization in the 15-minute market using all bids and base schedules submitted into the EIM. The 5-minute transfer volume is the result of optimization using all bids and base schedules submitted into EIM, based on unit commitments determined in the 15-minute market optimization. The maximum transfer capacities between EIM entities are shown in Graph 1 below.

Month	**From BAA**	**To BAA**	**15min EIM transfer (15m - base)**	**5min EIM transfer (5m - base)**
	AZPS	CISO	89,259	52,854
	AZPS	NEVP	8,471	11,814
	AZPS	PACE	52,935	61,497
	PWRX	CISO	2,016	7,222
	PWRX	PSEI	4,273	4,938
	CISO	AZPS	142,487	166,250
	CISO	PWRX	34,857	68,950
	CISO	NEVP	233,565	350,928
	CISO	PACW	41,529	44,198
	CISO	PGE	17,533	37,415
	IPCO	NEVP	12,169	8,221

	IPCO	PACE	91,356	101,309
	IPCO	PACW	9,646	15,893
	NEVP	AZPS	5,406	5,671
	NEVP	CISO	53,947	27,912
	NEVP	IPCO	26,035	41,257
April	NEVP	PACE	204,274	274,597
	PACE	AZPS	64,107	39,919
	PACE	IPCO	7,718	9,562
	PACE	NEVP	25,087	13,176
	PACE	PACW	42,094	58,876
	PACW	CISO	71,122	71,143
	PACW	IPCO	53,734	52,491
	PACW	PACE	4,861	4,664
	PACW	PGE	14,535	15,530
	PACW	PSEI	28,039	22,234
	PGE	CISO	1,308	932
	PGE	PACW	51,560	54,636
	PSEI	PWRX	41,984	34,794
	PSEI	PACW	64,692	75,999
	AZPS	CISO	79,186	58,612
	AZPS	NEVP	6,799	9,669
	AZPS	PACE	147,558	167,836
	PWRX	CISO	2,187	15,366
	PWRX	PSEI	13,495	12,808
	CISO	AZPS	233,548	262,529
	CISO	PWRX	4,853	42,926
	CISO	NEVP	293,407	376,027
	CISO	PACW	76,019	79,156
	CISO	PGE	18,466	35,840
	IPCO	NEVP	10,415	6,581
	IPCO	PACE	100,808	128,040
May	IPCO	PACW	10,955	14,188
	NEVP	AZPS	7,585	7,654
	NEVP	CISO	39,997	22,674
	NEVP	IPCO	44,642	64,778
	NEVP	PACE	221,644	259,597
	PACE	AZPS	43,829	28,075
	PACE	IPCO	11,255	9,077
	PACE	NEVP	14,271	7,871
	PACE	PACW	61,697	79,721

	PACW	CISO	25,955	26,488
	PACW	IPCO	65,804	79,229
	PACW	PACE	5,410	5,163
	PACW	PGE	21,139	19,376
	PACW	PSEI	27,037	19,023
	PGE	CISO	2,320	1,849
	PGE	PACW	39,492	47,397
	PSEI	PWRX	21,036	18,951
	PSEI	PACW	37,571	45,165
	AZPS	CISO	96,903	75,340
	AZPS	NEVP	18,885	16,349
	AZPS	PACE	45,446	66,710
	PWRX	CISO	2,795	32,103
	PWRX	PSEI	19,098	15,222
	CISO	AZPS	127,789	163,425
	CISO	PWRX	1,973	25,658
	CISO	NEVP	240,113	309,317
	CISO	PACW	48,425	49,982
	CISO	PGE	16,217	24,100
	IPCO	NEVP	25,190	20,322
	IPCO	PACE	60,239	81,078
	IPCO	PACW	24,550	27,811
Jun	NEVP	AZPS	7,139	7,097
	NEVP	CISO	41,304	24,735
	NEVP	IPCO	29,033	50,693
	NEVP	PACE	193,873	241,623
	PACE	AZPS	61,089	43,344
	PACE	IPCO	36,671	26,880
	PACE	NEVP	17,686	8,911
	PACE	PACW	67,636	81,623
	PACW	CISO	60,915	62,106
	PACW	IPCO	46,573	56,249
	PACW	PACE	5,013	5,035
	PACW	PGE	19,898	18,725
	PACW	PSEI	28,862	21,731
	PGE	CISO	3,417	3,218
	PGE	PACW	67,546	72,302
	PSEI	PWRX	26,390	27,641
	PSEI	PACW	47,045	45,385

TABLE 2: Energy transfers (MWh) in the FMM and RTD markets for Q2 2018



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400* **
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150

** Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.*

*** When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.*

GRAPH 1: Estimated maximum transfer capacity (EIM entities operating in Q2 2018)

WHEEL THROUGH TRANSFERS

As the footprint of the EIM grows and continues to change, wheel through transfers may become more common. Currently, an EIM entity facilitating a wheel through receives no direct financial benefit for facilitating the wheel; only the sink and source directly benefit. As part of the EIM Consolidated Initiatives stakeholder process, the ISO committed to monitoring the wheel through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits. The ISO committed to tracking the volume of wheels through in the EIM market in this quarterly report. In order to derive the wheels through for each EIM BAA, the ISO uses the following calculation for every real-time interval dispatch:

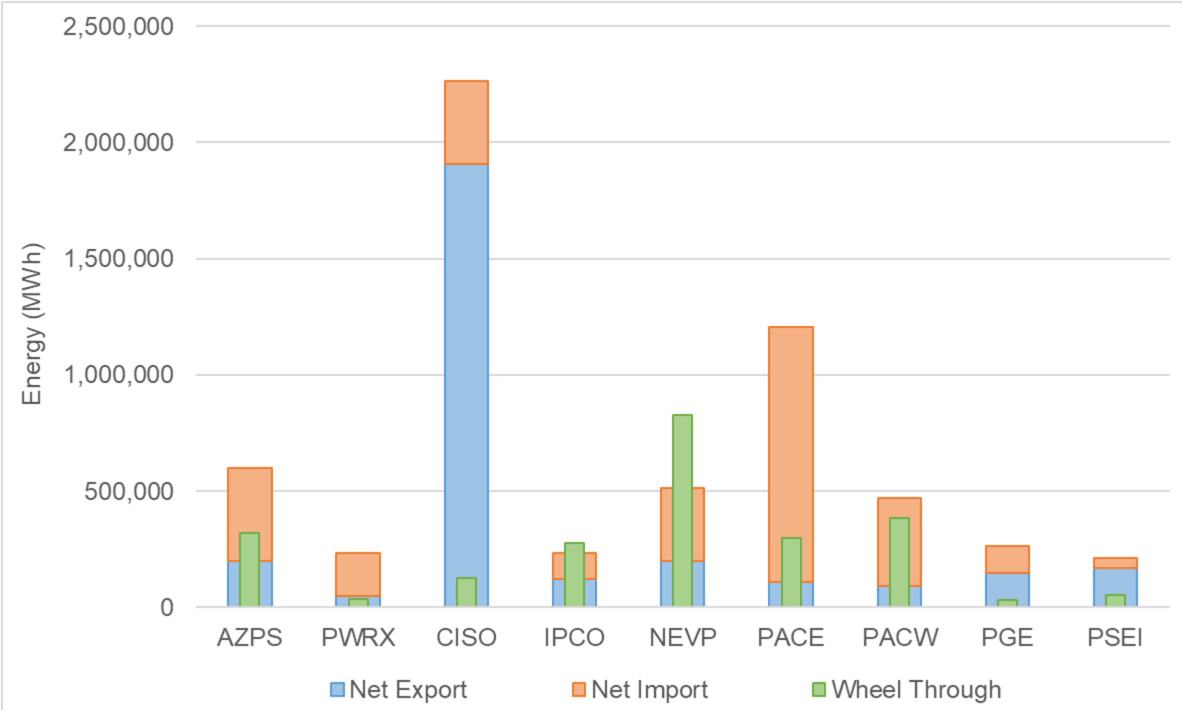
- Total import: summation of transfers above base transfers coming into the EIM BAA under analysis
- Total export: summation of all transfers above base transfers leaving the EIM BAA under analysis
- Net import: the maximum of zero or the difference between total imports and total exports
- Net export: the maximum of zero or the difference between total exports and total imports
- Wheel through: the minimum of the EIM transfers into (total import) or EIM transfer out (total export) of a BAA for a given interval

All wheels through are summed over the month or quarter. This volume reflects the total wheels through for each EIM BAA, regardless of the potential paths used to wheel through. The net imports and exports estimated in this section reflect the overall volume of net imports and exports; in contrast, the imports and exports provided in Table 2 reflect the gross transfers between two EIM BAAs.

The metric is measured as energy in MWh for each month and the corresponding calendar quarter, as shown in Tables 3 through 6 and Figures 2 through 5.

BAA	*Net Export*	*Net Import*	*Wheel Through*
AZPS	199,014	402,296	321,667
PWRX	50,635	181,896	37,024
CISO	1,909,497	355,349	127,205
IPCO	124,228	111,192	279,214
NEVP	200,007	312,017	828,282
PACE	108,331	1,099,203	298,704
PACW	92,398	380,002	386,788
PGE	146,556	117,205	33,778
PSEI	170,138	43,973	51,982

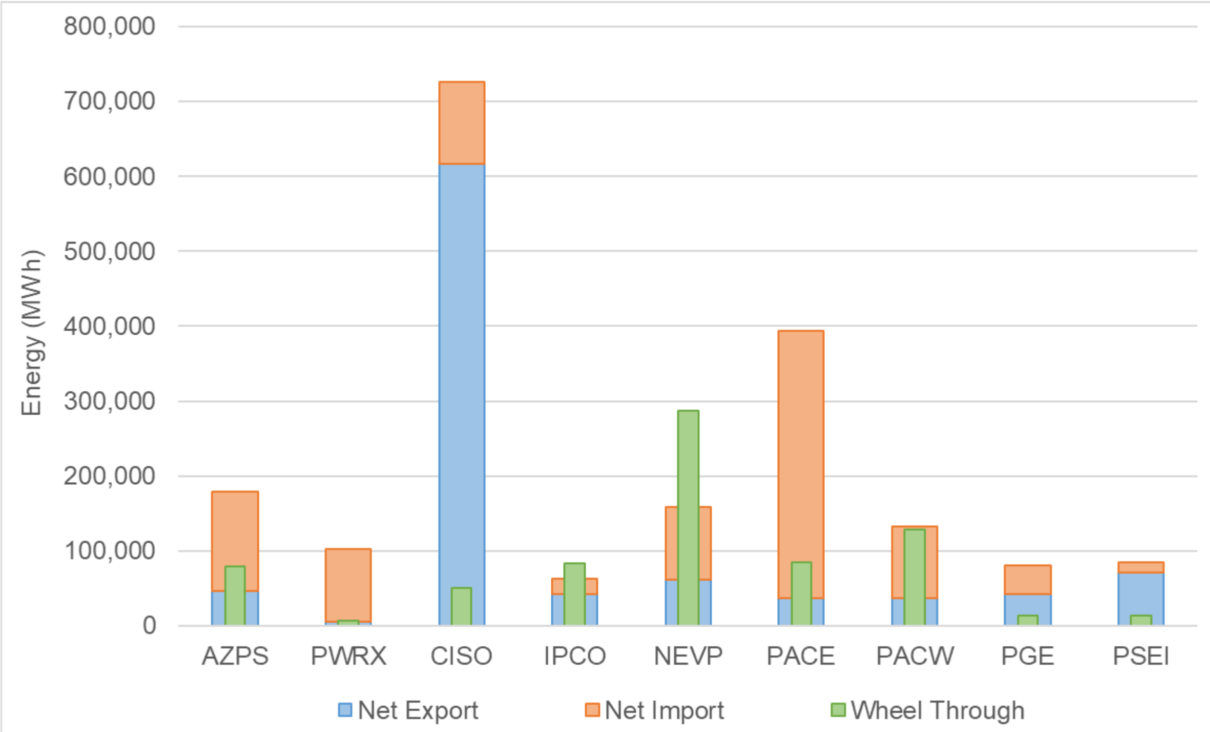
TABLE 3: Estimated wheel through transfers in Q2 2018



GRAPH 2: Estimated wheel through transfers in Q2 2018

BAA	Net Export	Net Import	Wheel Through
AZPS	46,859	132,535	79,305
PWRX	5,561	97,145	6,599
CISO	616,706	109,027	51,036
IPCO	42,444	20,332	82,978
NEVP	61,681	96,382	287,757
PACE	36,403	356,937	85,130
PACW	37,409	95,134	128,653
PGE	41,956	39,333	13,612
PSEI	71,540	13,733	13,439

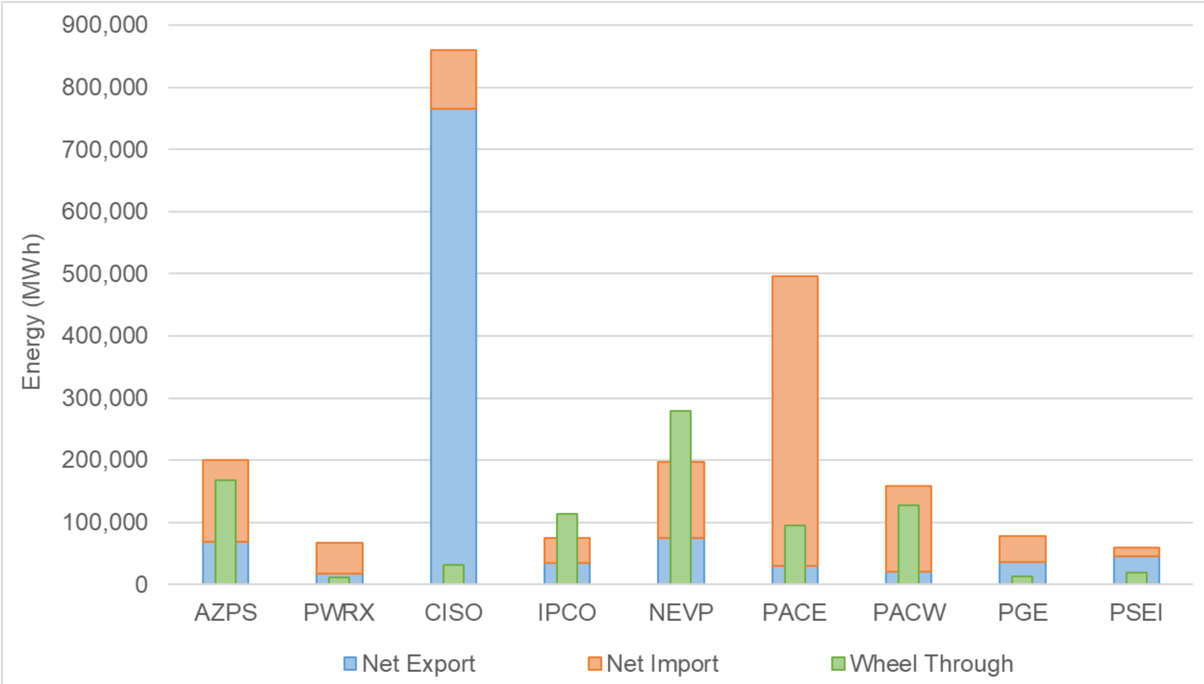
TABLE 4: Estimated wheel through transfers in April 2018



GRAPH 3: Estimated wheel through transfers in April 2018

BAA	Net Export	Net Import	Wheel Through
AZPS	68,824	130,965	167,293
PWRX	16,831	50,534	11,342
CISO	765,499	94,009	30,980
IPCO	34,847	39,312	113,962
NEVP	75,036	121,594	279,666
PACE	29,434	466,084	95,311
PACW	21,217	137,839	128,062
PGE	36,146	42,112	13,101
PSEI	45,799	13,514	18,317

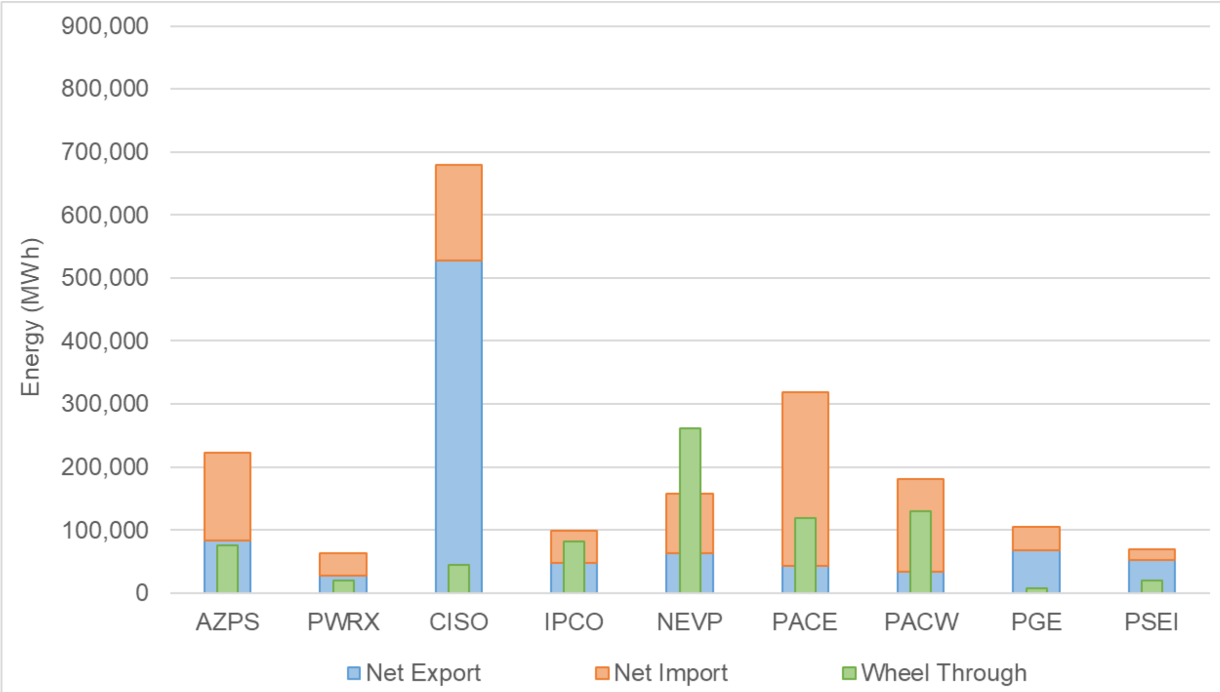
TABLE 5: Estimated wheel through transfers in May 2018



GRAPH 4: Estimated wheel through transfers in May 2018

BAA	Net Export	Net Import	Wheel Through
AZPS	83,330	138,796	75,069
PWRX	28,243	34,216	19,082
CISO	527,292	152,312	45,189
IPCO	46,937	51,548	82,274
NEVP	63,289	94,041	260,859
PACE	42,494	276,182	118,263
PACW	33,772	147,030	130,073
PGE	68,455	35,760	7,065
PSEI	52,799	16,726	20,227

TABLE 6: Estimated wheel through transfers in June 2018



GRAPH 5: Estimated wheel through transfers in June 2018

REDUCED RENEWABLE CURTAILMENT AND GHG REDUCTIONS

The EIM benefit calculation includes the economic benefits that can be attributed to avoided renewable curtailment within the ISO. If not for energy transfers facilitated by the EIM, some renewable generation located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q2 2018 was calculated to be 46,921 MWh (April) + 57,349 MWh (May) + 24,859 MWh (June) = 129,128 MWh total.

The environmental benefits of avoided renewable curtailment are significant. Under the assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO_2/MWh, avoided curtailments displaced an estimated 55,267 metric tons of CO_2 for Q2 2018. Avoided renewable curtailments also may have contributed to an increased volume of renewable credits that would otherwise have been unavailable. This report does not quantify the additional value in dollars associated with this benefit. Total estimated reductions in the curtailment of renewable energy along with the associated reductions in CO_2 are shown in Table 7.

Year	Quarter	MWh	Eq. Tons CO2
2015	1	8,860	3,792
	2	3,629	1,553
	3	828	354
	4	17,765	7,521
2016	1	112,948	48,342
	2	158,806	67,969
	3	33,094	14,164
	4	23,390	10,011
2017	1	52,651	22,535
	2	67,055	28,700
	3	23,331	9,986
	4	18,060	7,730
2018	1	65,860	28,188
	2	129,128	55,267
	Total	**715,405**	**306,112**

TABLE 7: Total reduction in curtailment of renewable energy along with the associated reductions in CO2

FLEXIBLE RAMPING PROCUREMENT DIVERSITY SAVINGS

The EIM facilitates procurement of flexible ramping capacity in the FMM to address variability that may occur in the RTD. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirements. This difference is known as flexible ramping procurement diversity savings. Starting in November 2016, the ISO replaced the flexible ramping constraint with flexible ramping products that provide both upward and downward ramping. The minimum and maximum flexible ramping requirements for each BAA and for each direction are listed in Table 8.

Year	Month	BAA	Direction	Minimum requirement	Maximum requirement
2018	April	AZPS	up	25	252
		CISO	up	246	1,530
		NEVP	up	24	218
		PACE	up	85	319
		PACW	up	53	179
		PGE	up	43	150
		PSEI	up	41	152
		PWRX	up	65	288
		IPCO	up	56	92
		ALL EIM	**up**	**339**	**1,932**
		AZPS	down	17	196
		CISO	down	166	1,055
		NEVP	down	15	242
		PACE	down	69	300
		PACW	down	41	152
		PGE	down	53	189
		PSEI	down	23	135
		PWRX	down	66	399
		IPCO	down	50	96
		ALL EIM	**down**	**288**	**1,568**
2018	May	AZPS	up	0	199
		CISO	up	235	1,530
		NEVP	up	26	170
		PACE	up	107	319
		PACW	up	60	179
		PGE	up	43	147
		PSEI	up	31	152
		PWRX	up	60	166
		IPCO	up	60	92
		ALL EIM	**up**	**314**	**2,291**
		AZPS	down	0	180
		CISO	down	166	1,055
		NEVP	down	17	152
		PACE	down	89	269
		PACW	down	36	185
		PGE	down	61	189
		PSEI	down	26	127
		PWRX	down	69	145
		IPCO	down	54	96
		ALL EIM	**down**	**366**	**1,568**

2018	June	AZPS	up	28	199
		CISO	up	127	1,467
		NEVP	up	32	170
		PACE	up	93	319
		PACW	up	63	179
		PGE	up	45	147
		PSEI	up	35	152
		PWRX	up	66	296
		IPCO	up	55	92
		ALL EIM	**up**	**220**	**1,467**
		AZPS	down	27	180
		CISO	down	242	1,308
		NEVP	down	16	152
		PACE	down	97	269
		PACW	down	29	192
		PGE	down	52	189
		PSEI	down	34	127
		PWRX	down	67	198
		IPCO	down	33	96
		ALL EIM	**down**	**254**	**1,492**

Table 8: Flexible ramping requirements

The flexible ramping procurement diversity savings for all the intervals averaged over a month are shown in Table 9. The percentage savings is the average MW savings divided by the sum of the four individual BAA requirements.

	April		**May**		**June**	
Direction	Up	Down	Up	Down	Up	Down
Average MW saving	736	771	758	748	790	804
Sum of BAA requirements	1,656	1,681	1,609	1,695	1,649	1,704
Percentage savings	44%	46%	47%	44%	48%	47%

Table 9: Flexible ramping procurement diversity savings for second quarter 2018

Flexible ramping capacity may be used in RTD to handle uncertainties in the future interval. The RTD flexible ramping capacity is prorated to each BAA. Flexible ramping surplus MW is defined as the awarded flexible ramping capacity in RTD minus its share, and the flexible ramping surplus cost is defined as the flexible ramping surplus MW multiplied by the flexible ramping EIM-wide marginal price. A positive flexible ramping surplus MW is the capacity that a BAA provided to help other BAAs, and a negative flexible ramping surplus MW is the capacity that a BAA received from other BAAs. The EIM dispatch cost for a BAA with positive flexible ramping surplus MW is increased because some capacities are used to help other BAAs. The flexible ramping surplus cost is subtracted from the BAA's EIM dispatch cost to reflect the true dispatch cost of a BAA. Please see the Benefit Report Methodology in the Appendix for more details.

CONCLUSION

Participation in the western EIM continues to show that utilities can realize cost benefits and reduced carbon emissions. With $401.73 million in gross benefits to date, the realized savings are in line with analysis conducted by each EIM entity before they joined EIM. The EIM resource sharing also continues to have a positive effect on reducing greenhouse gas emissions by using renewable generation that otherwise would have been turned off. Use of this energy to meet demand across the EIM footprint is likely replacing less clean energy sources. The GHG quantified benefits from avoided curtailments of 306,112 metric tons from 2015 to date is roughly equivalent to avoiding the emissions from 64,359 passenger cars driven for one year.

WESTERN EIM BENEFITS REPORT

Third Quarter **2018**

October 29, 2018

WESTERN EIM BENEFITS REPORT

Fourth Quarter **2018**

January 31, 2019

CONTENTS

EXECUTIVE SUMMARY

Gross benefits from EIM since November 2014

$564.88 million

This report presents the benefits associated with participation in the western Energy Imbalance Market (EIM) for the fourth quarter of 2018. The benefits include cost savings and the use of surplus renewable energy.

The report shows the EIM is helping to displace less-clean energy supplies with surplus renewable energy that otherwise may have been curtailed.

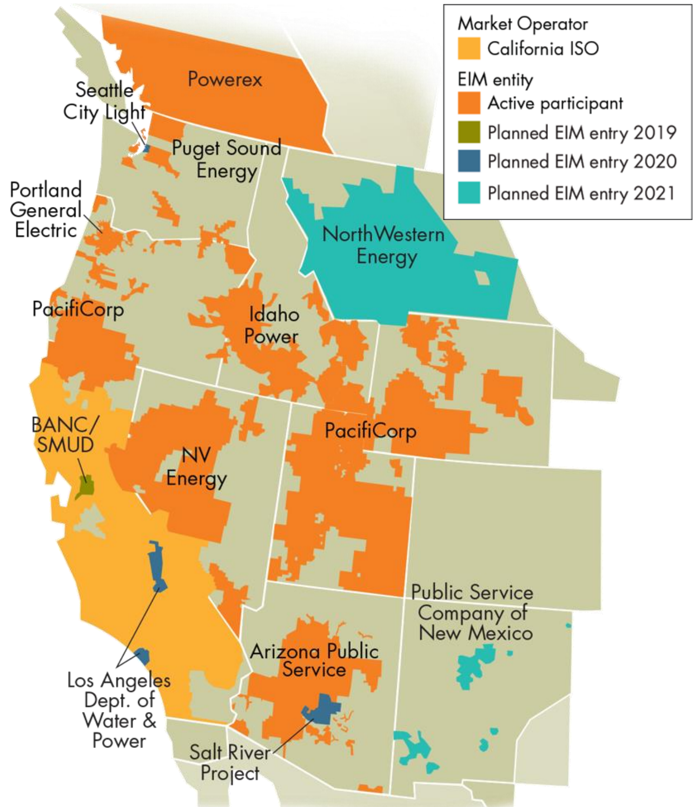
This analysis demonstrates the real-time market's ability to select the most economic resources across the EIM footprint.

Q4 2018 Gross Benefits by Participant

	(millions $)
Arizona Public Service	$10.03
California ISO	$4.14
Idaho Power	$5.82
NV Energy	$4.95
PacifiCorp	$21.68
Portland General Electric	$9.12
Powerex	$2.92
Puget Sound Energy	$3.91
Total	$62.57

*EIM Quarterly Benefit Report Methodology, https://www.caiso.com/Documents/EIM_BenefitMethodology.pdf

**The GHG emission reduction reported is associated with the avoided curtailment only. The current market process and counterfactual methodology cannot differentiate the GHG emissions resulting from serving ISO load via the EIM versus dispatch that would have occurred external to the ISO without the EIM. For more details, see http://www.caiso.com/Documents/GreenhouseGasEmissionsTrackingReport-FrequentlyAskedQuestions.pdf



2018 Q4 BENEFITS

ECONOMICAL

$62.57M

Gross benefits realized due to more efficient inter-and intra-regional dispatch in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD)*

ENVIRONMENTAL

10,026

Metric tons of CO_2** avoided curtailments

OPERATIONAL

46%

Average reduction in flexibility reserves across the footprint

BACKGROUND

The EIM began financially binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp Balancing Authority Areas (BAAs). NV Energy began participating in December 2015, Arizona Public Service and Puget Sound Energy began participating on October 1, 2016, and Portland General Electric began participating on October 1, 2017. Most recently, Idaho Power and Powerex began participating on April 4, 2018. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and extends to the border with Canada. The EIM facilitates renewable resource integration and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region.

The ISO began publishing quarterly EIM benefit reports in January 2015. Prior reports can be accessed at https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.The benefits quantified in this report fall into three main categories and were described in earlier studies[1].

EIM BENEFITS IN Q4 2018

Table 1 shows the estimated EIM gross benefits by each region per month[2]. The monthly savings presented in the table show $18.17 million for October, $19.90 million for November, and $24.50 million for December with a total estimated benefit of $62.57 million for the quarter.

Region	October	November	December	Total
APS	$3.94	$2.92	$3.17	$10.03
ISO	$0.27	$1.17	$2.70	$4.14
IPCO	$2.01	$1.70	$2.11	$5.82
NVE	$1.73	$1.51	$1.71	$4.95
PAC	$5.25	$6.79	$9.64	$21.68
PGE	$3.20	$3.04	$2.88	$9.12
PWRX	$0.62	$1.23	$1.07	$2.92
PSE	$1.15	$1.54	$1.22	$3.91
Total	$18.17	$19.90	$24.50	$62.57

TABLE 1: Fourth quarter 2018 benefits in millions USD by month

[1] PacifiCorp-ISO, Energy Imbalance Market Benefits, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

[2] The EIM benefits reported here are calculated based on available data. Intervals without complete data are excluded in the calculation. The intervals excluded due to unavailable data are normally within a few percent of the total intervals.

INTER-REGIONAL TRANSFERS

A significant contributor to EIM benefits is transfers across balancing areas, providing access to lower cost supply, while factoring in the cost of compliance with greenhouse gas (GHG) emissions regulations when energy is transferred into the ISO. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the Fifteen-Minute Market and Real-Time Dispatch (RTD).

Generally, transfer limits are based on transmission and interchange rights that participating balancing authority areas make available to the EIM, with the exception of the PacifiCorp West (PACW)-ISO transfer limit and the Portland General Electric (PGE)-ISO transfer limit in RTD. These RTD transfer capacities between PACW/PGE and the ISO are determined based on the allocated dynamic transfer capability driven by system operating conditions. This report does not quantify a BAA's opportunity cost that the utility considered when using its transfer rights for the EIM.

Table 2 provides the 15-minute and 5-minute EIM transfer volumes with base schedule transfers excluded. The EIM entities submit inter-BAA transfers in their base schedules. The benefits quantified in this report are only attributable to the transfers that occurred through the EIM. The benefits do not include any transfers attributed to transfers submitted in the base schedules that are scheduled prior to the start of the EIM.

The transfer from BAA_x to BAA_y and the transfer from BAA_y to BAA_x are separately reported. For example, if there is a 100 MWh transfer during a 5-minute interval, in addition to a base transfer from ISO to NVE, it will be reported as 100 MWh from_BAA ISO to_BAA NEVP, and 0 MWh from_BAA NEVP to_BAA ISO in the opposite direction. The 15-minute transfer volume is the result of optimization in the 15-minute market using all bids and base schedules submitted into the EIM. The 5-minute transfer volume is the result of optimization using all bids and base schedules submitted into EIM, based on unit commitments determined in the 15-minute market optimization. The maximum transfer capacities between EIM entities are shown in Graph 1 below.

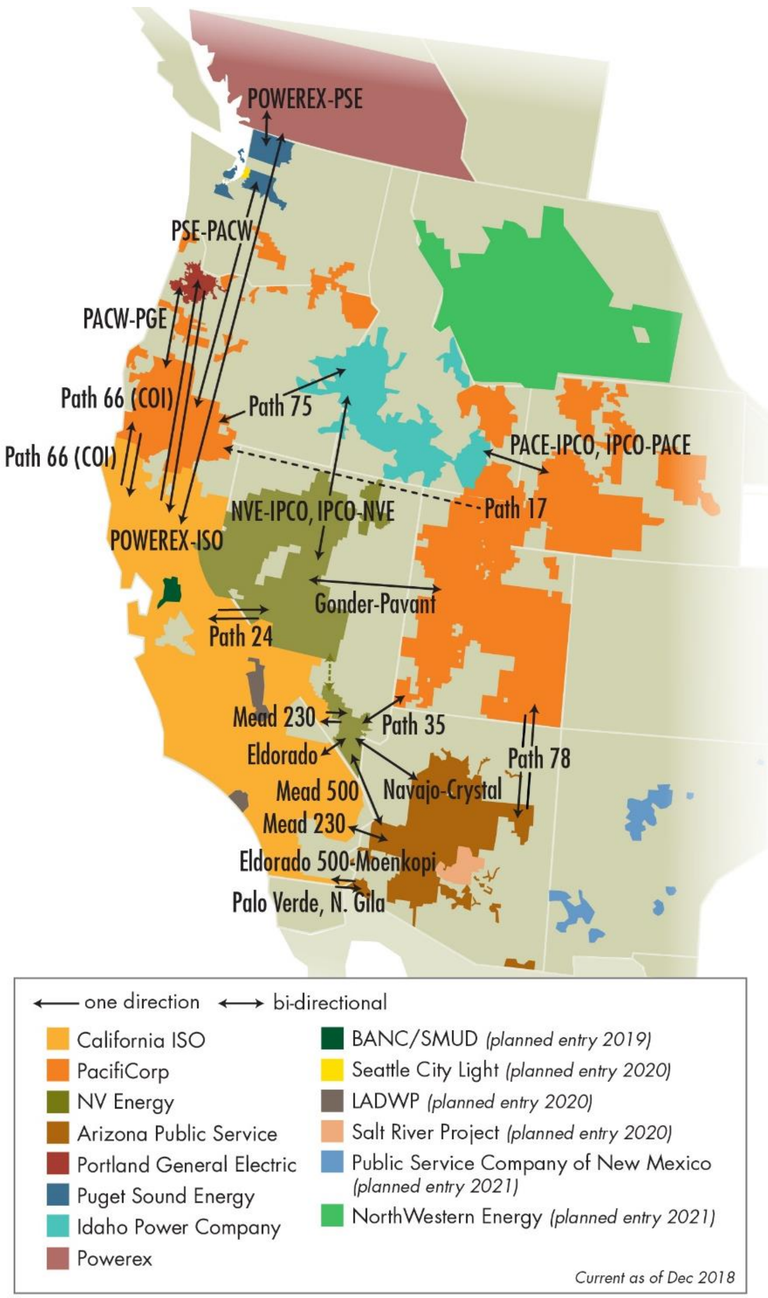
Month	**From BAA**	**To BAA**	**15min EIM transfer**	**5min EIM transfer**
			(15m - base)	**(5m - base)**
	AZPS	CISO	268,032	225,871
	AZPS	NEVP	16,165	16,001
	AZPS	PACE	6,736	13,685
	PWRX	CISO	6,195	12,223
	PWRX	PSEI	12,608	10,948
	CISO	AZPS	23,670	32,188
	CISO	PWRX	13,852	57,896

	CISO	NEVP	37,645	54,413
	CISO	PACW	30,949	36,199
	CISO	PGE	25,572	42,618
	IPCO	NEVP	35,456	21,214
	IPCO	PACE	1,627	344
	IPCO	PACW	19,198	25,888
	NEVP	AZPS	1,278	1,032
	NEVP	CISO	114,251	80,962
	NEVP	IPCO	19,553	25,635
October	NEVP	PACE	27,818	35,086
	PACE	AZPS	155,165	125,119
	PACE	IPCO	77,359	82,985
	PACE	NEVP	45,144	39,034
	PACE	PACW	42,878	49,660
	PACW	CISO	35,625	41,972
	PACW	IPCO	33,926	27,655
	PACW	PGE	63,566	63,175
	PACW	PSEI	86,778	70,492
	PGE	CISO	13,754	11,531
	PGE	PACW	13,417	14,884
	PSEI	PWRX	59,268	50,768
	PSEI	PACW	18,657	13,711
	AZPS	CISO	183,991	188,198
	AZPS	NEVP	7,268	9,480
	AZPS	PACE	6,844	12,966
	PWRX	CISO	3,317	10,210
	PWRX	PSEI	3,666	2,560

	CISO	AZPS	12,597	17,832
	CISO	PWRX	13,604	55,802
	CISO	NEVP	32,739	41,804
	CISO	PACW	21,578	24,133
	CISO	PGE	20,394	31,463
	IPCO	NEVP	43,739	40,839
	IPCO	PACE	3,862	4,790
November	IPCO	PACW	13,979	17,530
	NEVP	AZPS	1,433	774
	NEVP	CISO	133,783	99,555
	NEVP	IPCO	13,045	13,723
	NEVP	PACE	32,717	43,534
	PACE	AZPS	98,914	102,251
	PACE	IPCO	44,800	47,716
	PACE	NEVP	96,508	78,199
	PACE	PACW	24,261	26,700
	PACW	CISO	42,659	59,195
	PACW	IPCO	42,150	38,690
	PACW	PGE	78,729	68,864
	PACW	PSEI	66,472	53,287
	PGE	CISO	5,576	5,285
	PGE	PACW	21,310	21,493
	PSEI	PWRX	75,701	73,797
	PSEI	PACW	15,706	18,095
	AZPS	CISO	155,376	143,656
	AZPS	NEVP	7,274	8,802
	AZPS	PACE	5,968	11,512

	PWRX	CISO	4,301	16,887
	PWRX	PSEI	9,140	6,301
	CISO	AZPS	14,545	23,147
	CISO	PWRX	34,029	75,432
	CISO	NEVP	31,481	48,599
	CISO	PACW	25,258	29,450
	CISO	PGE	16,842	32,983
	IPCO	NEVP	49,070	40,381
	IPCO	PACE	165	230
	IPCO	PACW	12,519	15,466
December	NEVP	AZPS	1,911	2,367
	NEVP	CISO	153,235	116,901
	NEVP	IPCO	25,786	30,883
	NEVP	PACE	21,645	28,426
	PACE	AZPS	131,106	122,285
	PACE	IPCO	16,429	20,933
	PACE	NEVP	133,096	123,342
	PACE	PACW	41,966	46,627
	PACW	CISO	81,620	96,236
	PACW	IPCO	41,026	41,317
	PACW	PGE	88,244	84,008
	PACW	PSEI	100,221	83,195
	PGE	CISO	6,718	6,309
	PGE	PACW	10,030	12,275
	PSEI	PWRX	58,646	55,110
	PSEI	PACW	14,719	12,624

TABLE 2: Energy transfers (MWh) in the FMM and RTD markets for Q4 2018



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
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Path 78 *(PACE to APS)*	625
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PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <–> PSE	150
Powerex <–> ISO	150

[1] *Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.*

[2] *When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.*

GRAPH 1: Estimated maximum transfer capacity (EIM entities operating in Q4 2018)

WHEEL THROUGH TRANSFERS

As the footprint of the EIM grows and continues to change, wheel through transfers may become more common. Currently, an EIM entity facilitating a wheel through receives no direct financial benefit for facilitating the wheel; only the sink and source directly benefit. As part of the EIM Consolidated Initiatives stakeholder process, the ISO committed to monitoring the wheel through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits. The ISO will continue to track the volume of wheels through in the EIM market in the quarterly reports. In order to derive the wheels through for each EIM BAA, the ISO uses the following calculation for every real-time interval dispatch:

- Total import: summation of transfers above base transfers coming into the EIM BAA under analysis
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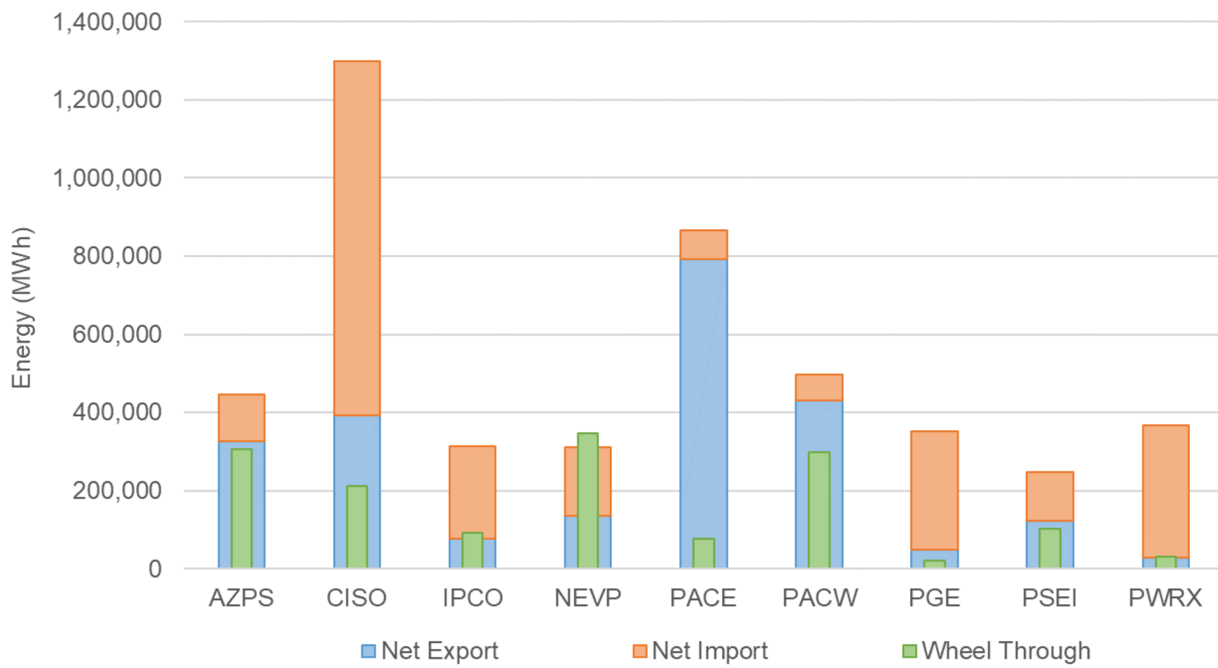
- Net import: the maximum of zero or the difference between total imports and total exports
- Net export: the maximum of zero or the difference between total exports and total imports
- Wheel through: the minimum of the EIM transfers into (total import) or EIM transfer out (total export) of a BAA for a given interval

All wheel throughs are summed over both the month and the quarter. This volume reflects the total wheels through for each EIM BAA, regardless of the potential paths used to wheel through. The net imports and exports estimated in this section reflect the overall volume of net imports and exports; in contrast, the imports and exports provided in Table 2 reflect the gross transfers between two EIM BAAs.

The metric is measured as energy in MWh for each month and the corresponding calendar quarter, as shown in Tables 3 through 6 and Figures 2 through 5.

BAA	*Net Export*	*Net Import*	*Wheel Through*
AZPS	325,227	121,580	306,653
CISO	393,149	905,963	212,642
IPCO	75,652	239,138	91,853
NEVP	134,185	177,799	346,543
PACE	792,070	75,036	75,904
PACW	430,822	66,377	299,342
PGE	50,008	302,013	21,937
PSEI	122,841	125,345	102,066
PWRX	27,934	338,638	31,513

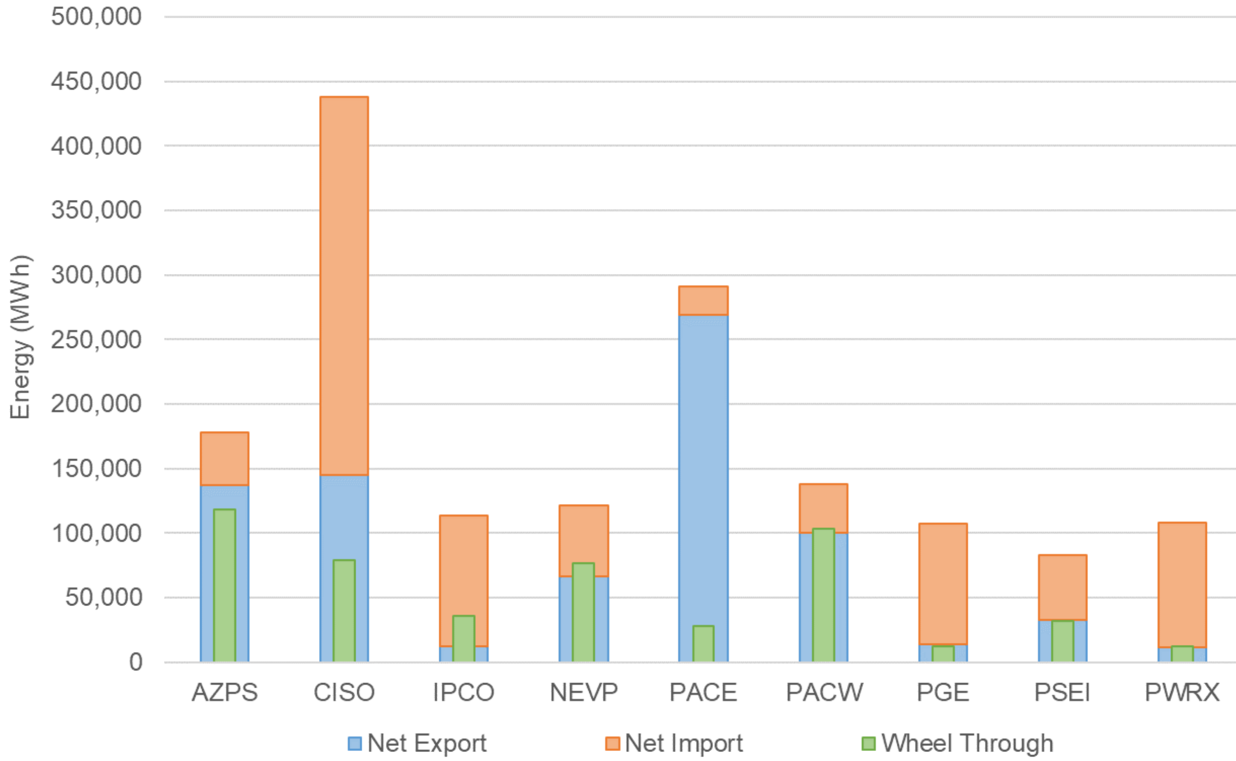
TABLE 3: Estimated wheel through transfers in Q4 2018



GRAPH 2: **Estimated wheel through transfers in Q4 2018**

BAA	Net Export	Net Import	Wheel Through
AZPS	137,379	40,237	118,367
CISO	144,699	293,552	79,272
IPCO	12,086	101,270	35,422
NEVP	66,728	54,788	76,278
PACE	269,472	21,277	27,957
PACW	100,306	37,264	103,349
PGE	13,985	93,525	12,435
PSEI	32,761	49,814	31,861
PWRX	11,351	97,041	11,897

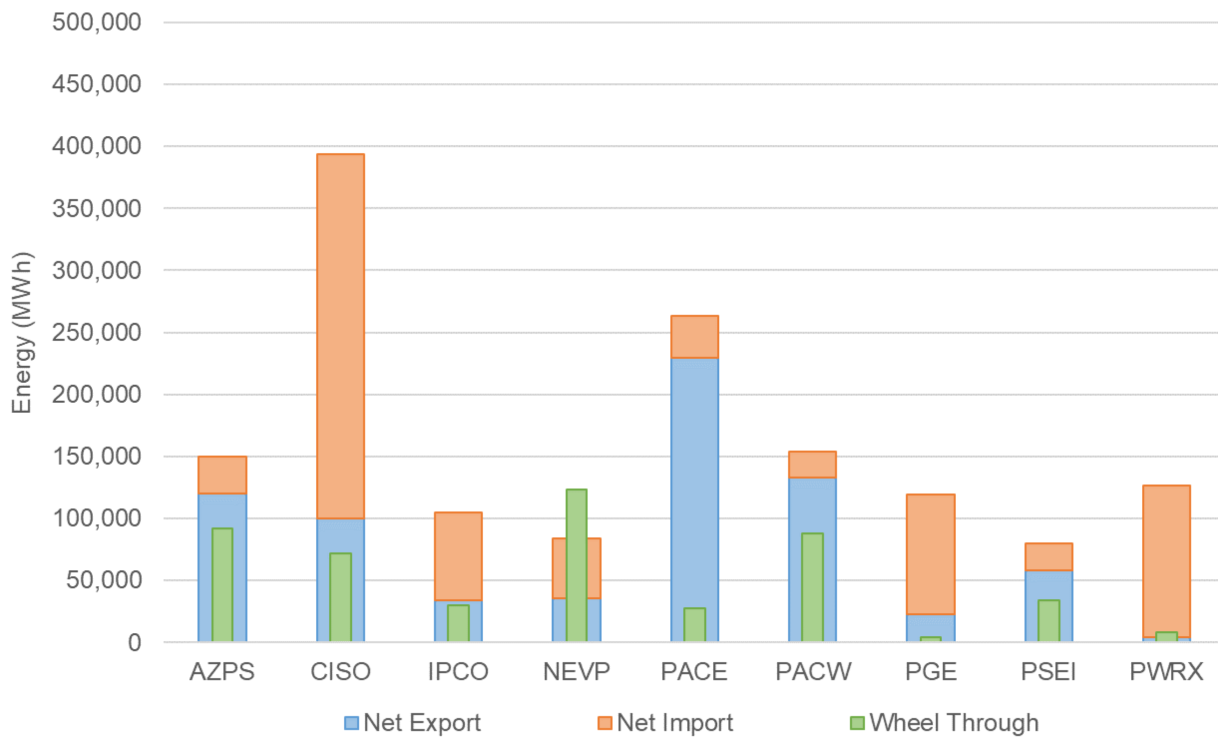
TABLE 4: Estimated wheel through transfers in October 2018



GRAPH 3: Estimated wheel through transfers in October 2018

BAA	Net Export	Net Import	Wheel Through
AZPS	120,037	29,869	91,724
CISO	99,767	293,769	71,451
IPCO	33,937	71,021	29,832
NEVP	35,541	48,355	123,262
PACE	229,514	34,079	27,245
PACW	133,167	20,355	87,940
PGE	22,793	96,518	4,118
PSEI	58,158	21,768	34,228
PWRX	4,579	121,757	8,381

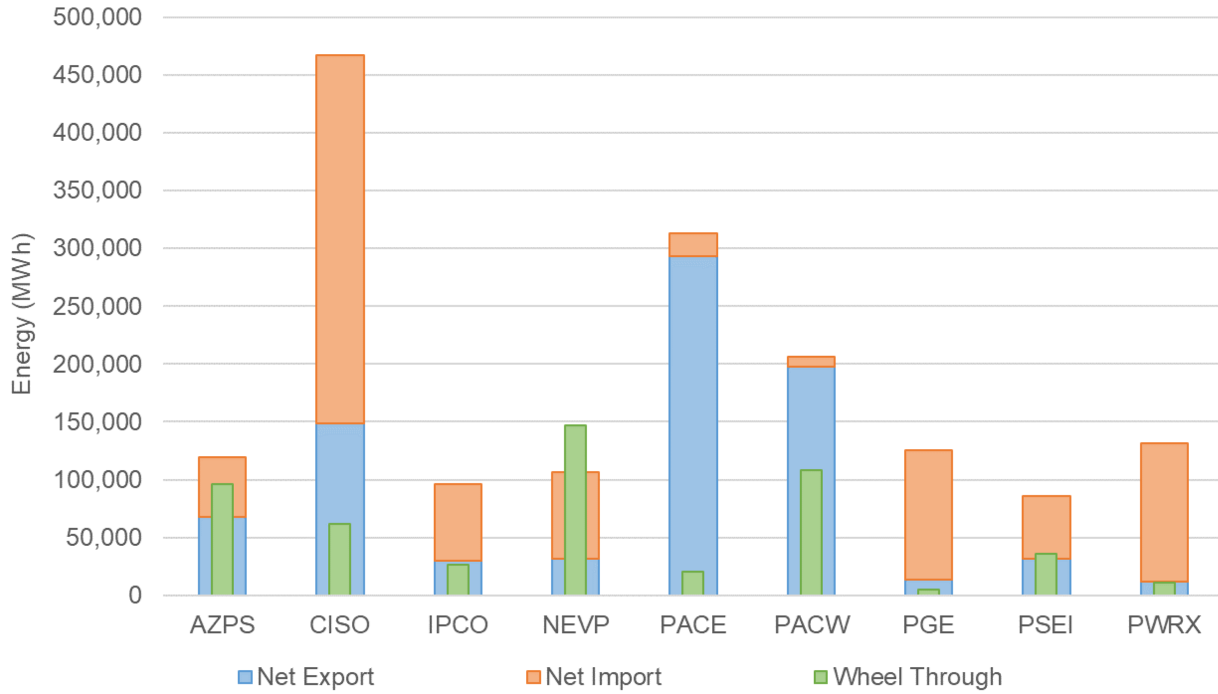
TABLE 5: Estimated wheel through transfers in November 2018



GRAPH 4: Estimated wheel through transfers in November 2018

BAA	Net Export	Net Import	Wheel Through
AZPS	67,810	51,474	96,562
CISO	148,684	318,643	61,920
IPCO	29,629	66,848	26,599
NEVP	31,916	74,656	147,003
PACE	293,084	19,680	20,701
PACW	197,349	8,757	108,053
PGE	13,230	111,969	5,384
PSEI	31,922	53,762	35,978
PWRX	12,004	119,840	11,234

TABLE 6: Estimated wheel through transfers in December 2018



GRAPH 5: Estimated wheel through transfers in December 2018

REDUCED RENEWABLE CURTAILMENT AND GHG REDUCTIONS

The EIM benefit calculation includes the economic benefits that can be attributed to avoided renewable curtailment within the ISO footprint. If not for energy transfers facilitated by the EIM, some renewable generation located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q4 2018 was calculated to be 7,048 MWh (October) + 6,664 MWh (November) + 9,713 MWh (December) = 23,425 MWh total.

The environmental benefits of avoided renewable curtailment are significant. Under the assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO_2/MWh, avoided curtailments displaced an estimated 10,026 metric tons of CO_2 for Q4 2018. Avoided renewable curtailments also may have contributed to an increased volume of renewable credits that would otherwise have been unavailable. This report does not quantify the additional value in dollars associated with this benefit. Total estimated reductions in the curtailment of renewable energy along with the associated reductions in CO_2 are shown in Table 7.

Year	Quarter	MWh	Eq. Tons CO2
2015	1	8,860	3,792
	2	3,629	1,553
	3	828	354
	4	17,765	7,521
2016	1	112,948	48,342
	2	158,806	67,969
	3	33,094	14,164
	4	23,390	10,011
2017	1	52,651	22,535
	2	67,055	28,700
	3	23,331	9,986
	4	18,060	7,730
2018	1	65,860	28,188
	2	129,128	55,267
	3	19,032	8,146
	4	23,425	10,026
	Total	757,862	324,284

TABLE 7: Total reduction in curtailment of renewable energy along with the associated reductions in CO2

FLEXIBLE RAMPING PROCUREMENT DIVERSITY SAVINGS

The EIM facilitates procurement of flexible ramping capacity in the FMM to address variability that may occur in the RTD. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirements. This difference is known as flexible ramping procurement diversity savings. Starting in November 2016, the ISO replaced the flexible ramping constraint with flexible ramping products that provide both upward and downward ramping. The minimum and maximum flexible ramping requirements for each BAA and for each direction are listed in Table 8.

Year	Month	BAA	Direction	Minimum requirement	Maximum requirement
2018	October	AZPS	up	35	199
		CISO	up	149	1,499
		NEVP	up	28	170
		PACE	up	83	319
		PACW	up	42	146
		PGE	up	37	147
		PSEI	up	28	152
		PWRX	up	73	279
		IPCO	up	47	222
		ALL EIM	**up**	**316**	**1,630**
		AZPS	down	31	180
		CISO	down	211	1,316
		NEVP	down	22	152
		PACE	down	90	269
		PACW	down	30	173
		PGE	down	25	189
		PSEI	down	39	127
		PWRX	down	65	198
		IPCO	down	23	208
		ALL EIM	**down**	**300**	**1,492**
2018	November	AZPS	up	0	199
		CISO	up	0	1,499
		NEVP	up	0	170
		PACE	up	0	319
		PACW	up	0	179
		PGE	up	0	147

		PSEI	up	0	152
		PWRX	up	0	268
		IPCO	up	0	222
		ALL EIM	**up**	**0**	**1,630**
		AZPS	down	0	180
		CISO	down	0	1,316
		NEVP	down	0	152
		PACE	down	0	269
		PACW	down	0	151
		PGE	down	0	189
		PSEI	down	0	127
		PWRX	down	0	198
		IPCO	down	0	208
		ALL EIM	**down**	**0**	**1,492**
2018	December	AZPS	up	19	199
		CISO	up	182	1,701
		NEVP	up	35	170
		PACE	up	93	319
		PACW	up	50	179
		PGE	up	30	147
		PSEI	up	23	152
		PWRX	up	79	268
		IPCO	up	43	222
		ALL EIM	**up**	**348**	**1,823**
		AZPS	down	25	190
		CISO	down	180	1,349
		NEVP	down	19	152
		PACE	down	69	321

	PACW	down	27	151
	PGE	down	27	189
	PSEI	down	33	145
	PWRX	down	75	230
	IPCO	down	53	208
	ALL EIM	**down**	**161**	**1,492**

Table 8: Flexible ramping requirements

The flexible ramping procurement diversity savings for all the intervals averaged over the month are shown in Table 9. The percentage savings is the average MW savings divided by the sum of the four individual BAA requirements.

	October		**November**		**December**	
Direction	Up	Down	Up	Down	Up	Down
Average MW saving	743	754	753	749	752	765
Sum of BAA requirements	1,645	1,674	1,625	1,674	1,654	1,611
Percentage savings	45%	45%	46%	45%	45%	47%

Table 9: Flexible ramping procurement diversity savings in Q4 2018

Flexible ramping capacity may be used in RTD to handle uncertainties in the future interval. The RTD flexible ramping capacity is prorated to each BAA. Flexible ramping surplus MW is defined as the awarded flexible ramping capacity in RTD minus its share, and the flexible ramping surplus cost is defined as the flexible ramping surplus MW multiplied by the flexible ramping EIM-wide marginal price. A positive flexible ramping surplus MW is the capacity that a BAA provided to help other BAAs, and a negative flexible ramping surplus MW is the capacity that a BAA received from other BAAs. The EIM dispatch cost for a BAA with positive flexible ramping surplus MW is increased because some capacities are used to help other BAAs. The flexible ramping surplus cost is subtracted from the BAA's EIM dispatch cost to reflect the true dispatch cost of a BAA. Please see the Benefit Report Methodology in the Appendix for more details.

CONCLUSION

With $564.88 million in gross benefits to date, the Western EIM demonstrates that through increased coordination and optimization in the west, utilities can realize cost benefits and reduce carbon emissions. Sharing resources across a larger geographic area, even if it's just in real-time, continues to have a positive effect of reducing greenhouse gas emissions by using renewable generation that otherwise would have been turned off. Use of this energy to meet demand across the EIM footprint is likely replacing less clean energy sources. The quantified benefits from avoided curtailments of renewable generation from 2015 to date reached 324,284 metric tons of CO_2, roughly the equivalent of avoiding the emissions from 68,179 passenger cars driven for one year.

CONTENTS

EXECUTIVE SUMMARY

Gross benefits from EIM since November 2014

$502.31 million

This report presents the benefits associated with participation in the western Energy Imbalance Market (EIM) for the third quarter of 2018. The benefits include cost savings and the use of surplus renewable energy.

The report shows the EIM is helping to displace less-clean energy supplies with surplus renewable energy that otherwise may have been curtailed.

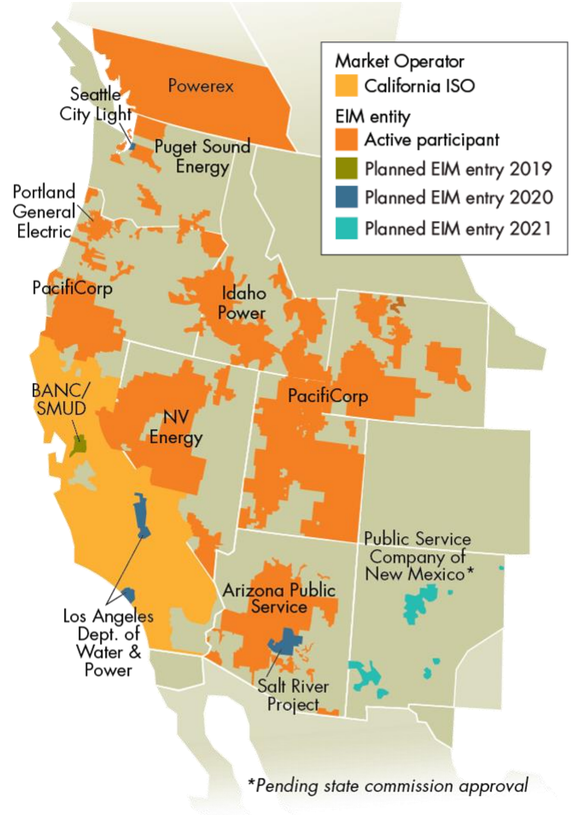
This analysis demonstrates the real-time market's ability to select the most economic resources across the EIM footprint.

Q3 2018 Gross Benefits by Participant

	(millions $)
Arizona Public Service	$20.78
California ISO	$21.02
Idaho Power	$13.31
NV Energy	$11.09
PacifiCorp	$17.82
Portland General Electric	$9.47
Powerex	$2.65
Puget Sound Energy	$4.44
Total	$100.58

*EIM Quarterly Benefit Report Methodology, https://www.caiso.com/Documents/EIM_BenefitMethodology.pdf

**The GHG emission reduction reported is associated with the avoided curtailment only. The current market process and counterfactual methodology cannot differentiate the GHG emissions resulting from serving ISO load via the EIM versus dispatch that would have occurred external to the ISO without the EIM. For more details, see http://www.caiso.com/Documents/GreenhouseGasEmissionsTrackingReport-FrequentlyAskedQuestions.pdf



2018 Q3 BENEFITS

ECONOMICAL

$100.58M

Gross benefits realized due to more efficient inter-and intra-regional dispatch in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD)*

ENVIRONMENTAL

8,146

Metric tons of CO_2** avoided curtailments

OPERATIONAL

48%

Average reduction in flexibility reserves across the footprint

BACKGROUND

The EIM began financially binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs. NV Energy began participating in December 2015, Arizona Public Service and Puget Sound Energy began operations October 1, 2016, and Portland General Electric began participation on October 1, 2017. Most recently, Idaho Power and Powerex began participation on April 4, 2018. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and extends to the border with Canada. The EIM facilitates renewable resource integration and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region.

The ISO began publishing quarterly EIM benefit reports in January 2015. Prior reports can be accessed at https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.The benefits quantified in this report fall into three main categories and were described in earlier studies.[1]

EIM BENEFITS IN Q3 2018

Table 1 shows the estimated EIM gross benefits by each region per month[2]. The monthly savings presented in the table show $39.66 million for July, $45.09 million for August, and $15.83 million for September with a total estimated benefit of $100.58 million. The benefits in Quarter 3 of this year were higher than usual due to more economical transfers in periods of high loads and higher electric prices following higher fuel prices. This was mainly observed in July and August; the estimated benefits dropped in September to typical ranges tracking lower load levels and fuel prices.

Region	July	August	September	Total
APS	$9.48	$9.34	$1.96	$20.78
ISO	$9.93	$7.85	$3.24	$21.02
IPCO	$4.55	$6.36	$2.40	$13.31
NVE	$4.07	$4.96	$2.06	$11.09
PAC	$5.80	$9.46	$2.56	$17.82
PGE	$3.29	$3.90	$2.28	$9.47
PWRX	$0.93	$1.20	$0.52	$2.65
PSE	$1.61	$2.02	$0.81	$4.44
Total	$39.66	$45.09	$15.83	$100.58

TABLE 1: Third quarter 2018 benefits in millions USD by month

[1] PacifiCorp-ISO, Energy Imbalance Market Benefits, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

[2] The EIM benefits reported here are calculated based on available data. Intervals without complete data are excluded in the calculation. The intervals excluded due to unavailable data are normally within a few percent of the total intervals.

INTER-REGIONAL TRANSFERS

A significant contributor to EIM benefits is transfers across balancing areas, providing access to lower cost supply, while factoring in the cost of compliance with greenhouse gas (GHG) emissions regulations when energy is transferred into the ISO. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the Fifteen-Minute Market and Real-Time Dispatch (RTD).

Generally, transfer limits are based on transmission and interchange rights that participating balancing authority areas make available to the EIM, with the exception of the PacifiCorp West (PACW)-ISO transfer limit and the Portland General Electric (PGE)-ISO transfer limit in RTD. These RTD transfer capacities between PACW/PGE and the ISO are determined based on the allocated dynamic transfer capability driven by system operating conditions. This report does not quantify a BAA's opportunity cost that the utility considered when using its transfer rights for the EIM.

Table 2 provides the 15-minute and 5-minute EIM transfer volumes with base schedule transfers excluded. The EIM entities submit inter-BAA transfers in their base schedules. The benefits quantified in this report are only attributable to the transfers that occurred through the EIM. The benefits do not include any transfers attributed to transfers submitted in the base schedules that are scheduled prior to the start of the EIM.

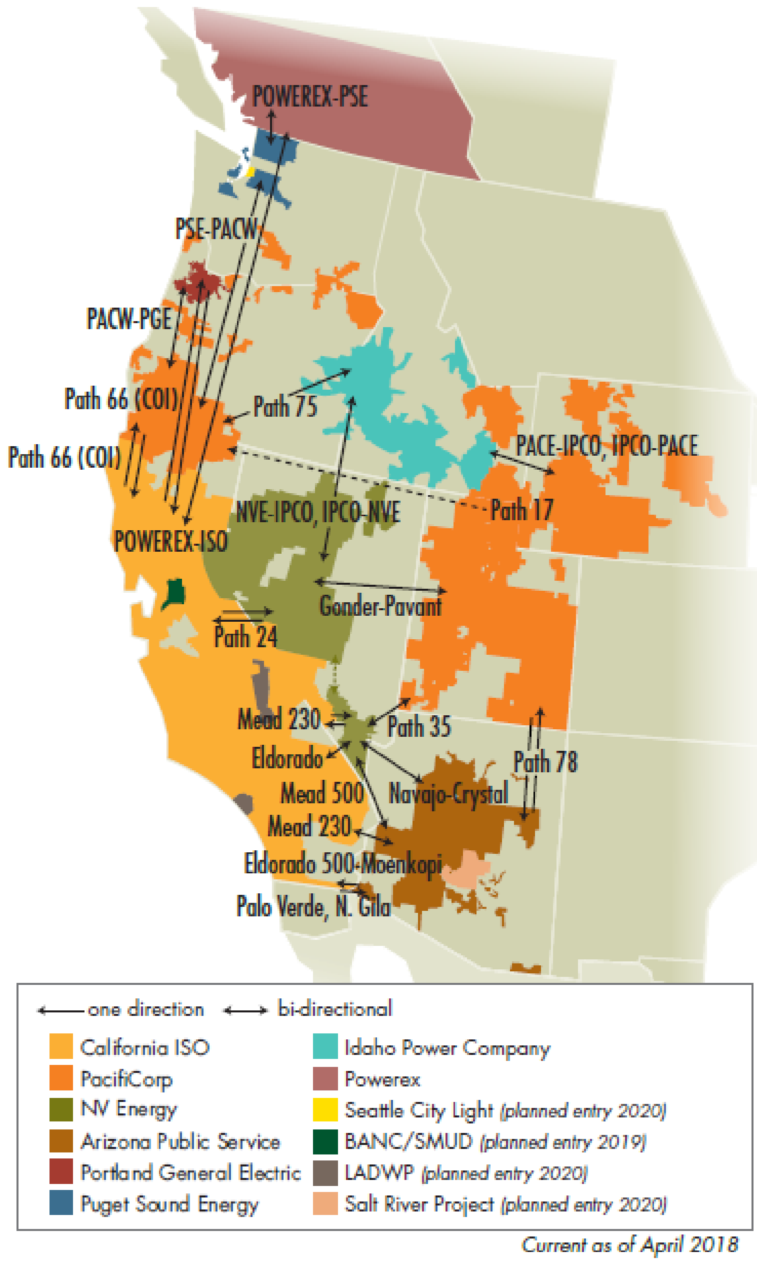
The transfer from BAA_x to BAA_y and the transfer from BAA_y to BAA_x are separately reported. For example, if there is a 100 MWh transfer during a 5-minute interval, in addition to a base transfer from ISO to NVE, it will be reported as 100 MWh from_BAA ISO to_BAA NEVP, and 0 MWh from_BAA NEVP to_BAA ISO in the opposite direction. The 15-minute transfer volume is the result of optimization in the 15-minute market using all bids and base schedules submitted into the EIM. The 5-minute transfer volume is the result of optimization using all bids and base schedules submitted into EIM, based on unit commitments determined in the 15-minute market optimization. The maximum transfer capacities between EIM entities are shown in Graph 1 below.

Month	**From BAA**	**To BAA**	**15min EIM transfer (15m - base)**	**5min EIM transfer (5m - base)**
	AZPS	CISO	308,299	279,306
	AZPS	NEVP	27,273	35,453
	AZPS	PACE	4,011	8,601
	PWRX	CISO	7,039	28,128
	PWRX	PSEI	9,400	6,692
	CISO	AZPS	20,542	26,108
	CISO	PWRX	6,801	34,025
	CISO	NEVP	38,074	63,089
	CISO	PACW	15,181	17,545
	CISO	PGE	13,349	18,579
	IPCO	NEVP	74,651	65,046

	IPCO	PACE	2,465	4,813
	IPCO	PACW	17,963	22,938
	NEVP	AZPS	2,320	9,577
	NEVP	CISO	115,574	93,098
	NEVP	IPCO	4,954	8,886
July	NEVP	PACE	45,656	70,036
	PACE	AZPS	172,719	138,028
	PACE	IPCO	72,451	79,468
	PACE	NEVP	57,884	47,170
	PACE	PACW	58,997	68,577
	PACW	CISO	95,257	113,554
	PACW	IPCO	2,900	2,446
	PACW	PGE	88,242	87,902
	PACW	PSEI	85,520	70,970
	PGE	CISO	6,914	6,990
	PGE	PACW	22,942	24,336
	PSEI	PWRX	58,595	51,164
	PSEI	PACW	17,454	14,592
	AZPS	CISO	336,838	283,392
	AZPS	NEVP	22,131	24,404
	AZPS	PACE	741	1,482
	PWRX	CISO	8,351	31,923
	PWRX	PSEI	10,750	5,366
	CISO	AZPS	11,866	19,684
	CISO	PWRX	6,057	30,432
	CISO	NEVP	38,398	74,357
	CISO	PACW	9,133	11,754
	CISO	PGE	3,567	9,171
	IPCO	NEVP	85,822	64,415
	IPCO	PACE	1,526	1,442
August	IPCO	PACW	15,845	27,465
	NEVP	AZPS	1,203	669
	NEVP	CISO	124,984	92,743
	NEVP	IPCO	848	3,196
	NEVP	PACE	24,691	39,164
	PACE	AZPS	212,357	167,794
	PACE	IPCO	80,531	84,948
	PACE	NEVP	57,552	49,692
	PACE	PACW	46,273	69,641
	PACW	CISO	97,488	117,688
	PACW	IPCO	10,267	7,198

	PACW	PGE	61,184	65,115
	PACW	PSEI	65,444	55,071
	PGE	CISO	7,118	10,097
	PGE	PACW	29,562	30,402
	PSEI	PWRX	56,383	56,670
	PSEI	PACW	30,585	30,024
September	AZPS	CISO	233,913	205,634
	AZPS	NEVP	8,977	10,413
	AZPS	PACE	5,816	6,534
	PWRX	CISO	5,484	19,446
	PWRX	PSEI	9,140	4,692
	CISO	AZPS	31,025	35,535
	CISO	PWRX	12,416	44,696
	CISO	NEVP	46,338	62,393
	CISO	PACW	24,419	30,382
	CISO	PGE	16,475	27,210
	IPCO	NEVP	51,248	34,159
	IPCO	PACE	2,378	2,232
	IPCO	PACW	25,976	33,741
	NEVP	AZPS	1,138	1,100
	NEVP	CISO	147,864	113,253
	NEVP	IPCO	8,312	13,675
	NEVP	PACE	46,582	57,825
	PACE	AZPS	155,787	121,870
	PACE	IPCO	35,502	40,515
	PACE	NEVP	76,716	66,272
	PACE	PACW	29,513	39,796
	PACW	CISO	66,992	82,093
	PACW	IPCO	36,858	23,759
	PACW	PGE	47,967	47,583
	PACW	PSEI	64,917	46,803
	PGE	CISO	2,102	4,064
	PGE	PACW	22,931	21,154
	PSEI	PWRX	54,029	48,050
	PSEI	PACW	25,278	25,967

TABLE 2: Energy transfers (MWh) in the FMM and RTD markets for Q3 2018



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400* **
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <--> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <--> PSE	150
Powerex <--> ISO	150

** Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.*

*** When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.*

GRAPH 1: Estimated maximum transfer capacity (EIM entities operating in Q3 2018)

WHEEL THROUGH TRANSFERS

As the footprint of the EIM grows and continues to change, wheel through transfers may become more common. Currently, an EIM entity facilitating a wheel through receives no direct financial benefit for facilitating the wheel; only the sink and source directly benefit. As part of the EIM Consolidated Initiatives stakeholder process, the ISO committed to monitoring the wheel through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits. The ISO will continue to track the volume of wheels through in the EIM market in the quarterly reports. In order to derive the wheels through for each EIM BAA, the ISO uses the following calculation for every real-time interval dispatch:

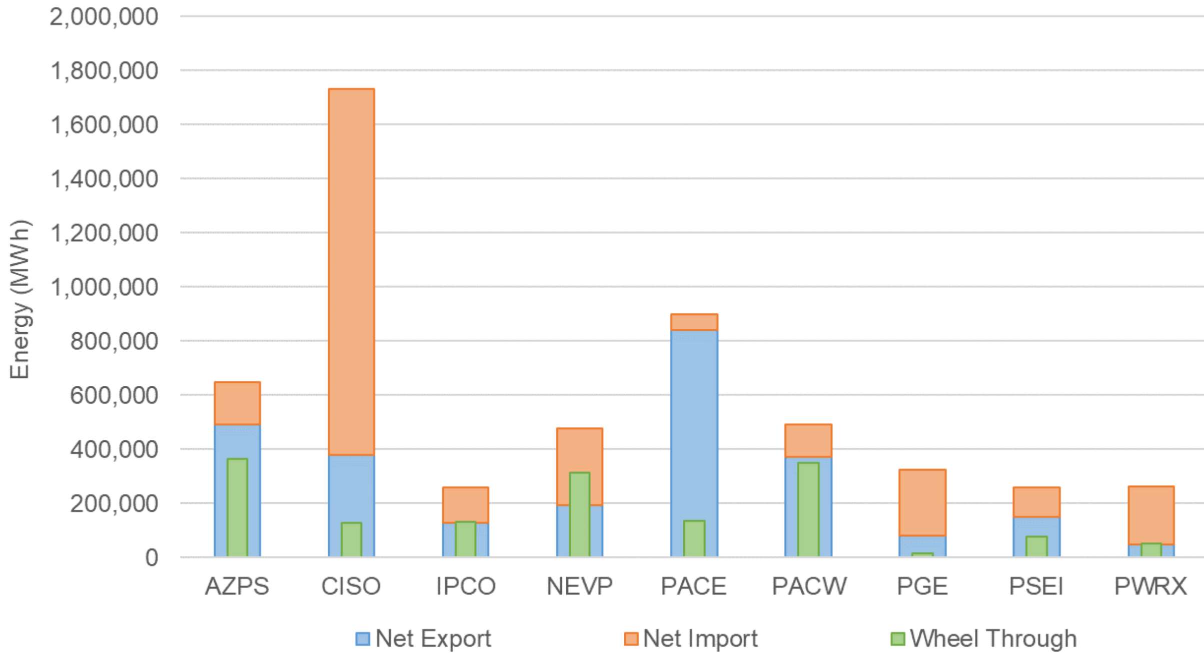
- Total import: summation of transfers above base transfers coming into the EIM BAA under analysis
- Total export: summation of all transfers above base transfers going out of the EIM BAA under analysis
- Net import: the maximum of zero or the difference between total imports and total exports
- Net export: the maximum of zero or the difference between total exports and total imports
- Wheel through: the minimum of the EIM transfers into (total import) or EIM transfer out (total export) of a BAA for a given interval

All wheel throughs are summed over both the month and the quarter. This volume reflects the total wheels through for each EIM BAA, regardless of the potential paths used to wheel through. The net imports and exports estimated in this section reflect the overall volume of net imports and exports; in contrast, the imports and exports provided in Table 2 reflect the gross transfers between two EIM BAAs.

The metric is measured as energy in MWh for each month and the corresponding calendar quarter, as shown in Tables 3 through 6 and Figures 2 through 5.

BAA	Net Import	Net Export	Wheel Through
AZPS	156,828	492,078	365,046
CISO	1,355,904	377,370	128,945
IPCO	133,902	126,231	130,799
NEVP	285,871	192,121	312,593
PACE	57,243	840,597	135,694
PACW	119,478	372,105	350,170
PGE	241,216	82,188	15,215
PWRX	215,351	46,284	50,323
PSEI	111,463	148,281	78,753

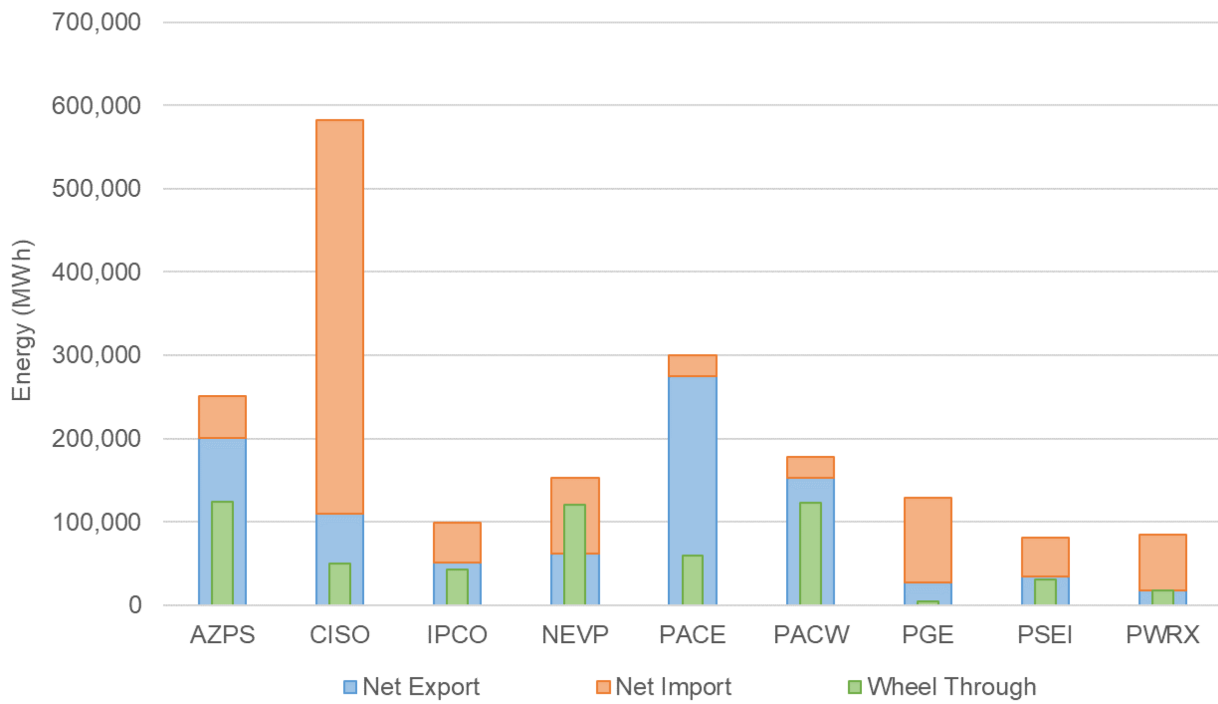
TABLE 3: Estimated wheel through transfers in Q3 2018



GRAPH 2: **Estimated wheel through transfers in Q3 2018**

BAA	Net Import	Net Export	Wheel Through
AZPS	50,085	200,290	123,922
CISO	472,764	110,109	49,683
IPCO	48,735	50,799	42,312
NEVP	91,011	61,971	120,253
PACE	24,685	274,731	59,127
PACW	25,294	152,402	123,123
PGE	102,186	26,739	4,649
PWRX	67,552	17,204	17,783
PSEI	46,489	34,555	31,347

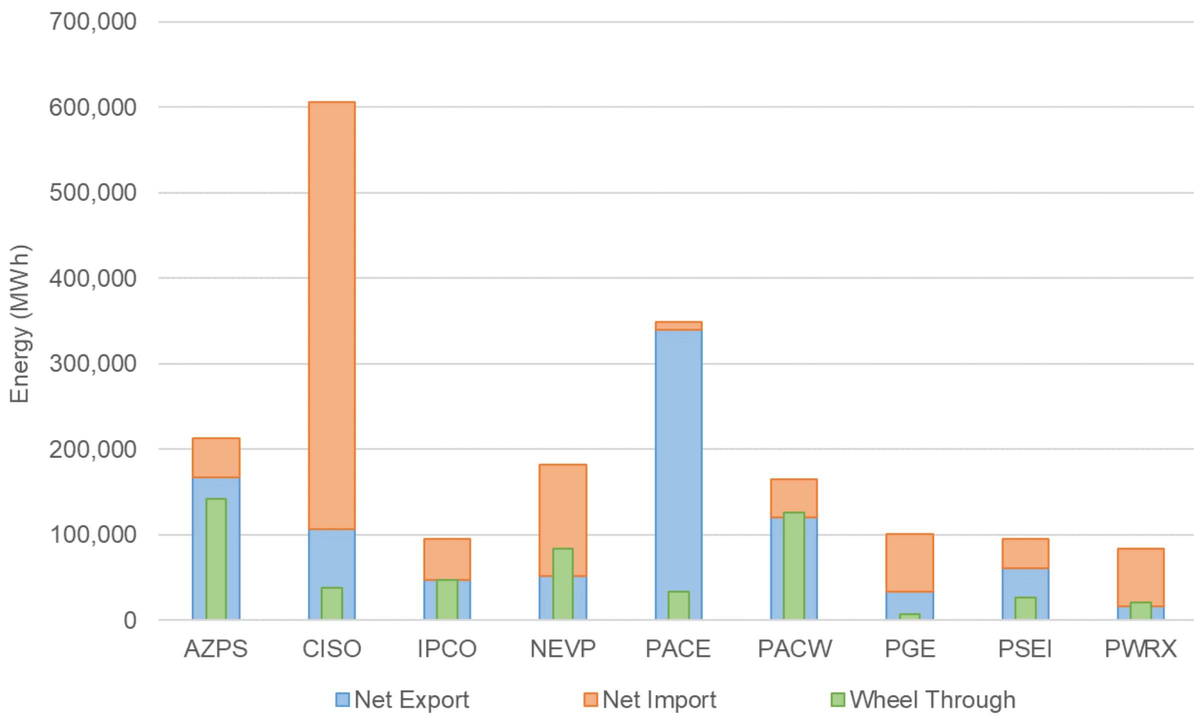
TABLE 4: Estimated wheel through transfers in July 2018



GRAPH 3: Estimated wheel through transfers in July 2018

BAA	Net Import	Net Export	Wheel Through
AZPS	45,924	167,558	142,655
CISO	499,048	107,162	38,498
IPCO	48,770	46,917	46,736
NEVP	129,643	52,349	83,879
PACE	8,873	339,691	33,368
PACW	44,486	120,518	125,551
PGE	67,445	33,868	6,926
PWRX	66,773	16,744	20,656
PSEI	34,347	60,504	26,476

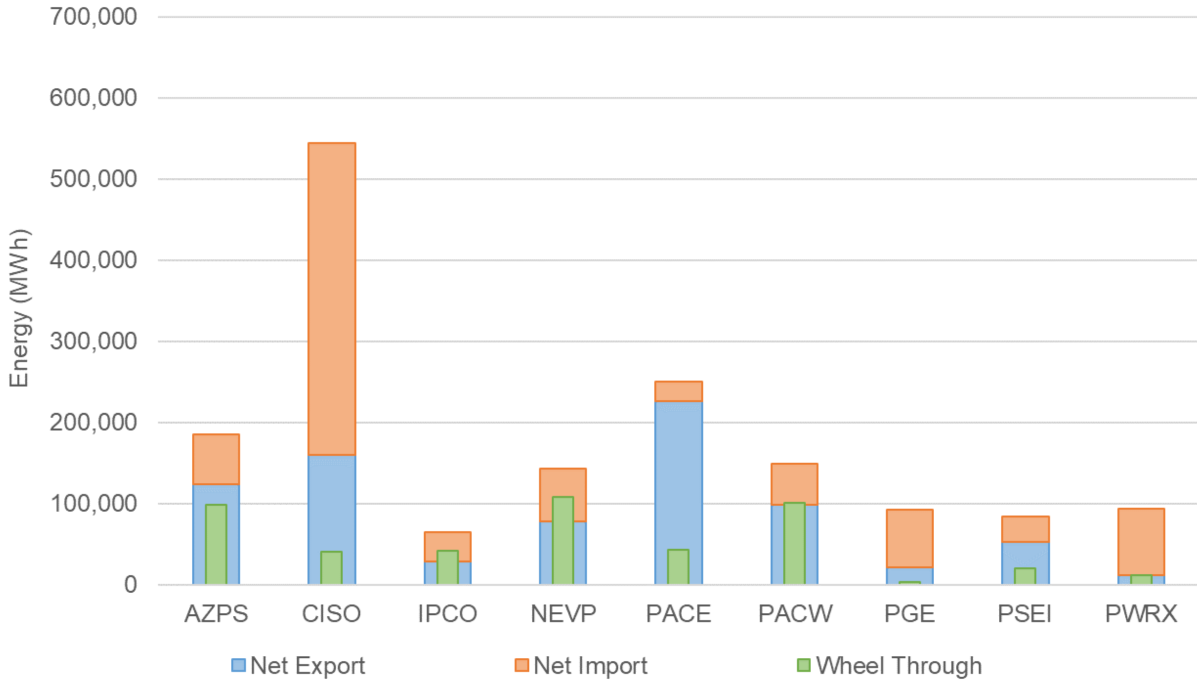
TABLE 5: Estimated wheel through transfers in August 2018



GRAPH 4: Estimated wheel through transfers in August 2018

BAA	Net Import	Net Export	Wheel Through
AZPS	60,818	124,230	98,469
CISO	384,092	160,099	40,763
IPCO	36,396	28,515	41,751
NEVP	65,217	77,801	108,461
PACE	23,685	226,175	43,199
PACW	49,697	99,185	101,496
PGE	71,585	21,580	3,640
PWRX	81,026	12,336	11,884
PSEI	30,627	53,222	20,930

TABLE 6: Estimated wheel through transfers in September 2018



GRAPH 5: Estimated wheel through transfers in September 2018

REDUCED RENEWABLE CURTAILMENT AND GHG REDUCTIONS

The EIM benefit calculation includes the economic benefits that can be attributed to avoided renewable curtailment within the ISO footprint. If not for energy transfers facilitated by the EIM, some renewable generation located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q3 2018 was calculated to be 5,206 MWh (July) + 5,879 MWh (August) + 7,947MWh (September) = 19,032 MWh total.

The environmental benefits of avoided renewable curtailment are significant. Under the assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO_2/MWh, avoided curtailments displaced an estimated 8,146 metric tons of CO_2 for Q3 2018. Avoided renewable curtailments also may have contributed to an increased volume of renewable credits that would otherwise have been unavailable. This report does not quantify the additional value in dollars associated with this benefit. Total estimated reductions in the curtailment of renewable energy along with the associated reductions in CO_2 are shown in Table 7.

Year	Quarter	MWh	Eq. Tons CO2
2015	1	8,860	3,792
	2	3,629	1,553
	3	828	354
	4	17,765	7,521
2016	1	112,948	48,342
	2	158,806	67,969
	3	33,094	14,164
	4	23,390	10,011
2017	1	52,651	22,535
	2	67,055	28,700
	3	23,331	9,986
	4	18,060	7,730
2018	1	65,860	28,188
	2	129,128	55,267
	3	19,032	8,146
	Total	734,437	314,258

TABLE 7: Total reduction in curtailment of renewable energy along with the associated reductions in CO2

FLEXIBLE RAMPING PROCUREMENT DIVERSITY SAVINGS

The EIM facilitates procurement of flexible ramping capacity in the FMM to address variability that may occur in the RTD. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA's requirements. This difference is known as flexible ramping procurement diversity savings. Starting in November 2016, the ISO replaced the flexible ramping constraint with flexible ramping products that provide both upward and downward ramping. The minimum and maximum flexible ramping requirements for each BAA and for each direction are listed in Table 8.

Year	Month	BAA	Direction	Minimum requirement	Maximum requirement
2018	July	AZPS	up	0	199
		CISO	up	0	1,499
		NEVP	up	0	170
		PACE	up	0	319
		PACW	up	0	161
		PGE	up	0	147
		PSEI	up	0	152
		PWRX	up	0	296
		IPCO	up	0	222
		ALL EIM	**up**	**0**	**1,630**
		AZPS	down	0	180
		CISO	down	0	1,294
		NEVP	down	0	152
		PACE	down	0	269
		PACW	down	0	192
		PGE	down	0	189
		PSEI	down	0	127
		PWRX	down	0	198
		IPCO	down	0	209
		ALL EIM	**down**	**0**	**1,492**
2018	August	AZPS	up	0	199
		CISO	up	0	1,499
		NEVP	up	0	170
		PACE	up	0	319
		PACW	up	0	179
		PGE	up	0	147
		PSEI	up	0	152
		PWRX	up	0	279
		IPCO	up	0	222
		ALL EIM	**up**	**0**	**1,630**
		AZPS	down	0	180
		CISO	down	0	1,316
		NEVP	down	0	152
		PACE	down	0	269
		PACW	down	0	192
		PGE	down	0	189
		PSEI	down	0	127
		PWRX	down	0	198
		IPCO	down	0	209
		ALL EIM	**down**	**0**	**1,492**

2018	September	AZPS	up	36	199
		CISO	up	0	1,499
		NEVP	up	39	170
		PACE	up	83	319
		PACW	up	46	143
		PGE	up	53	138
		PSEI	up	26	152
		PWRX	up	71	279
		IPCO	up	45	222
		ALL EIM	**up**	**250**	**1,630**
		AZPS	down	35	180
		CISO	down	231	1,316
		NEVP	down	27	152
		PACE	down	82	269
		PACW	down	31	188
		PGE	down	35	189
		PSEI	down	29	127
		PWRX	down	65	198
		IPCO	down	20	203
		ALL EIM	**down**	**300**	**1,492**

Table 8: Flexible ramping requirements

The flexible ramping procurement diversity savings for all the intervals averaged over a month are shown in Table 9. The percentage savings is the average MW savings divided by the sum of the four individual BAA requirements.

	July		**August**		**September**	
Direction	Up	Down	Up	Down	Up	Down
Average MW saving	864	877	807	845	741	798
Sum of BAA requirements	1,757	1,754	1,722	1,758	1,652	1,714
Percentage savings	49%	50%	47%	48%	45%	47%

Table 9: Flexible ramping procurement diversity savings for third quarter 2018

Flexible ramping capacity may be used in RTD to handle uncertainties in the future interval. The RTD flexible ramping capacity is prorated to each BAA. Flexible ramping surplus MW is defined as the awarded flexible ramping capacity in RTD minus its share, and the flexible ramping surplus cost is defined as the flexible ramping surplus MW multiplied by the flexible ramping EIM-wide marginal price. A positive flexible ramping surplus MW is the capacity that a BAA provided to help other BAAs, and a negative flexible ramping surplus MW is the capacity that a BAA received from other BAAs. The EIM dispatch cost for a BAA with positive flexible ramping surplus MW is increased because some capacities are used to help other BAAs. The flexible ramping surplus cost is subtracted from the BAA's EIM dispatch cost to reflect the true dispatch cost of a BAA. Please see the Benefit Report Methodology in the Appendix for more details.

CONCLUSION

With $502.31 million in gross benefits to date, the realized savings are in line with analysis conducted by each EIM entity before they joined EIM. Sharing resources across a larger geographic area, even if it's just in real-time, continues to have a positive effect of reducing greenhouse gas emissions by using renewable generation that otherwise would have been turned off. Use of this energy to meet demand across the EIM footprint is likely replacing less clean energy sources. The GHG quantified benefits from avoided curtailments of 314,258 metric tons from 2015 to date is roughly equivalent to avoiding the emissions from 66,071 passenger cars driven for one year. These reports also reflect variability from month to month and quarter to quarter, caused by seasonal conditions. Growing participation in the western EIM demonstrates that utilities can realize cost benefits and reduced carbon emissions with increased coordination and optimization in the west.

CASE: UE 350
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Opening Testimony

February 4, 2019

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

A. My name is Sabrinna Soldavini. I am a Utility 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. The purpose of my testimony is to discuss the issues of PURPA expense, re-pricing, and Bridger Coal Company depreciation expenses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/202, Idaho Power Responses to Staff Data Requests (DRs) and Exhibit Staff/203, Idaho Power's workpaper related to BCC Depreciation.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, PURPA EXPENSE

Q. How does Idaho Power's 2019 October update of PURPA expense differ from the previous year's October projection?

A. The 2019 October update estimates a total PURPA expense of $221.1 million.[1] The 2018 October update estimated a total $217.2 million in PURPA expense.[2] This is a $3.9 million, or two percent increase, from last year's October update, and represents approximately 57 percent of the 2019 October update NPSE.[3]

Q. How much of Idaho Power's generation comes from PURPA generation?

A. The 2019 October update includes 343 aMW of PUPRA generation for the test period, an increase of 11 aMW over the 2018 October update, which included 332 aMW of PURPA generation.[4] This 343 aMW accounts for approximately 19 percent of Idaho Power's generation in the 2019 October Update.

Q. Have any additional PUPRA projects been added to the forecast for the 2019 APCU?

A. Yes. The 2019 APCU includes the addition of six new PURPA projects.[5] The six new projects, including five solar projects and one hydro project, are expected to go online between July 30, 2019 and December 31, 2019.[6] The projects have a total combined nameplate capacity of 28.85 MWh.[7] The Company notes in its testimony that the six new PURPA projects are

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[1] Idaho Power/100, Blackwell/10.
[2] *Ibid.*
[3] *Ibid.*
[4] *Ibid.*
[5] *Ibid.*
[6] Staff/202, Soldavini/1 (IPC Response to Staff Data Requests 11 and 12).
[7] Idaho Power/100, Blackwell/10.

responsible for approximately 50 percent of the increase in PURPA expense, and an increase in forecasted PURPA generation and updated contract values are responsible for the remaining projected increase in PURPA expense.[8]

Q. Have there been any changes to how PURPA expenses are incorporated into the APCU?

A. Yes. As a result of the 2018 APCU, there is a new process for incorporating PURPA expenses in the March forecast.[9] In that case, Idaho Power, Staff and the Oregon Citizens' Utility Board (CUB) signed a stipulation that sets forth the future treatment of PURPA projects in the APCU. All new PURPA projects expected to come online during the APCU test period are included in the October update and assumed to operate for the entire 12-month test period to establish a normalized level of PURPA expenses to be included in base rates. However, for March updates beginning with this case, Idaho Power now also adjusts the forecast to incorporate each new PURPA project's expected online date. New PURPA projects expected to come online during the test period will have their forecasted generation and expense included in the forecast beginning in the month they are expected to come online. For example, Idaho Power expects the Brush Solar project to come online on July 30, 2019. Accordingly, the March update should include forecasted PUPRA generation and expense for Brush Solar beginning in July of the test period. The agreed-upon treatment also includes modification of the expected online date for any

[8] *Ibid.*
[9] Order 18-170 approving the Stipulation among Idaho Power, Staff and CUB.

new PUPRA project using the three-year average Contract Delay Rate (CDR) of historical PURPA projects.

Q. Has Staff verified compliance with the stipulated methodology in Order No. 18-170?

A. Staff has requested and received the names and expected online dates for the six new PURPA projects, and will review the March update to ensure the 2018 stipulation was adhered to.[10]

[10] Staff/202, Soldavini/1 (IPC Response to Staff Data Requests 11 and 12).

ISSUE 2, RE-PRICING OF AURORA

Q. Please provide background on the issue of re-pricing.

A. Idaho Power's initial testimony provides a thorough explanation of the process and history of the re-pricing process in Idaho Power/100, Blackwell/11 through Blackwell/13. I will provide a brief overview here.

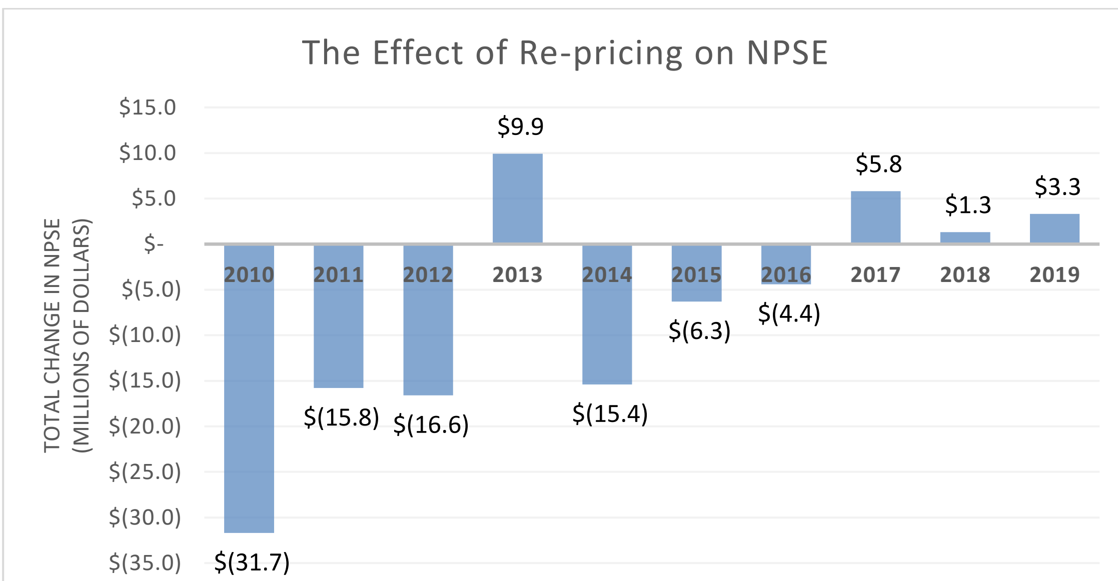
Idaho Power uses the AURORA model to forecast purchased power and surplus sales volumes for an April to March Test Period. The Company first utilizes AURORA-modeled electricity market prices to determine levels of purchased power and surplus sales volumes based on the concept of economic dispatch – optimizing the generation of electricity generation facilities to meet system load, at least cost. Pursuant to Order No. 05-871, these AURORA generated volumes are then re-priced using a forward electricity price curve for the Mid-Columbia (Mid-C) hub. Once re-priced and adjusted for inflation, these values become the final estimates for purchased power expense and surplus sales revenue in the Company's forecasted NPSE.

Q. How has re-pricing AURORA typically adjusted the NPSE estimates for the October update?

A. Generally, re-pricing the AURORA model has resulted in decreases to NPSE and benefits to Oregon ratepayers, through a combination of changes to forecasted purchased power expenses and surplus sales revenues. The results from re-pricing for the last 10-years can be seen in the table and chart below.

Figure 1 Re-Pricing and the Effect to NPSE ($Millions of Dollars)

Year	Before Repricing		After Repricing		Effect on NPSE
	Purchased Power Expense	Surplus Sales Revenue	Purchased Power Expense	Surplus Sales Revenue	
2010[11]	$40.2	$84.5	$38.4	$114.4	$ (31.7)
2011[12]	$36.3	$61.3	$42.1	$82.9	$(15.8)
2012[13]	$40.3	$86.9	$41.9	$105.1	$(16.6)
2013[14]	$29.6	$110.3	$14.3	$85.1	$9.9
2014[15]	$20.6	$72.5	$19.7	$86.9	$(15.4)
2015[16]	$15.0	$56.1	$14.2	$61.6	$(6.3)
2016[17]	$8.3	$54.8	$10.1	$61.0	$(4.4)
2017[18]	$16.0	$49.1	$14.9	$42.2	$5.8
2018[19]	$15.7	$31.3	$12.1	$26.4	$1.3
2019[20]	$13.4	$36.1	$11.0	$30.4	$3.3



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11 *See* UE 214 Idaho Power/100, Wright/7.
12 *See* UE 222 Idaho Power/100, Wright/6.
13 *See* UE 242 Idaho Power/100, Wright/6.
14 *See* UE 257 Idaho Power/100, Wright/8.
15 *See* UE 279 Idaho Power/100, Wright/8.
16 *See* UE 293 Idaho Power/100, Wright/7.
17 *See* UE 301 Idaho Power/100, Noe/13.
18 *See* UE 314 Idaho Power/100, Blackwell/13 through Blackwell/14.
19 *See* UE 333 Idaho Power/100, Blackwell/12
20 Idaho Power/100, Blackwell/13.

Observable from the data is a shift in both the magnitude and direction of the effect of re-pricing the AURORA modeled volumes. From 2010-2016, re-pricing produced benefits to Oregon ratepayers in the form of reduced NPSE costs. However, for the last three years, re-pricing has led to increases in total NPSE, with increases of $5.8, $1.3, and $3.3 million in 2017, 2018, and 2019 respectively.

Q. How has re-pricing adjusted the NPSE estimates for the October 2019 update?

A. For the October 2019 update, the AURORA-generated forecast for purchased power expenses and surplus sales revenues are $13.4 million and $36.1 million, respectively.[21] After re-pricing with Mid-C hub forward curves, purchased power expenses decrease by $2.4 million to $11.0 million, while surplus sales revenues decrease by $5.7 million to $30.4 million – resulting in a $3.3 million increase in NPSE.[22]

Q. Does Staff have a recommendation for this issue?

A. Staff is not recommending changes to the methodology at this time, but will continue to monitor the effect of re-pricing on NPSE. Additionally, Staff will continue to monitor actual versus projected purchased power expense and surplus sales revenue, with the goal of determining if the current methodology remains the best way to forecast these elements.

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[21] Idaho Power/100, Blackwell/13.
[22] *Ibid.*

ISSUE 3, BRIDGER COAL COMPANY DEPRECIATION

Q. Please explain Bridger Coal Company's (BCC) relationship to Idaho Power.

A. BCC is a joint venture of Idaho Power and PacifiCorp, which is owned by Idaho Energy Resources Co. (IERCO), a wholly owned subsidiary of Idaho Power, and a separate subsidiary of PacifiCorp. Pursuant to Commission order, "separate record and accounts for IERCO are maintained and the operation 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."[23]

Q. Please summarize Staff's analysis of BCC Depreciation.

A. In the 2018 APCU, Staff raised the issue of the Company's recovery of depreciation expense from ratepayers related to plant that has been added since the Company's last general rate case and has yet to be reviewed for prudence, as well as the depreciation rates of BCC assets[24]. In the 2018 stipulation approved in Order No. 18-170, the stipulating parties agreed that in subsequent APCUs, Idaho Power would submit workpapers detailing the justification of the depreciable lives of BCC assets as well as any variations to BCC depreciation levels from the levels established in the Company's most recent rate case.

[23] Order No. 91-567.
[24] *See* UE 333 Staff/200, Kaufman/5 through Kaufman/9.

Q. How has BCC depreciation expense varied since the Company's most recent rate case?

A. Idaho Power calculates total BCC depreciation expense for the period ranging from April 2017 – March 2018 at approximately **[Begin Confidential]** [redacted]. **[End Confidential]** This represents an approximately **[Begin Confidential]** [redacted] **[End Confidential]** over the prior year, which the Company notes is largely due to **[Begin Confidential]** [redacted] **[End Confidential]** Since the Company's last general rate case in 2011, BCC depreciation expense has ranged from approximately **[Begin Confidential]** [redacted] **[End Confidential]** [25]

Q. Has Staff confirmed Idaho Power provided the necessary workpapers, as outlined in Order No. 18-170?

A. Yes. Idaho Power has submitted workpapers as part of this year's APCU outlining the depreciable lives of BCC assets. The associated workpapers also include a description of how and why BCC depreciation expense has varied from the level set in its most recent general rate case.

Q. Does Staff have a recommendation for how BCC Depreciation costs should be treated?

A. Staff received supplemental information from Idaho Power on February 1, 2019 support of the Company's level of depreciation expense and plant retirement.

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[25] Staff/203, Soldavini/1.

As such, there is insufficient time to review the information before the filing of this testimony. Staff will continue its review of the issue, including the potential for further discovery, and reserves the right to make a future recommendation regarding BCC depreciation in this case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 350
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

February 4, 2019

WITNESS QUALIFICATION STATEMENT

NAME:	Sabrinna Soldavini
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Masters of Science, Agricultural Economics Purdue University, West Lafayette, Indiana Bachelor of Science, Economics University of Oregon, Eugene, Oregon
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities. Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in Data Analysis, and Program Coordination within the technology sector.

CASE: UE 350
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

February 4, 2019

STAFF'S DATA REQUEST NO. 11:

Please refer to Idaho Power/100, Blackwell/10. Please provide the name and expected online date for the six new PURPA QFs referenced therein. Please explain how the costs of these contracts are included in IPC's power cost forecast.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 11:

Please see the table below for the name and expected online date for the six new Public Utility Regulatory Policies Act of 1978 ("PURPA") projects included in the 2019 APCU.

Name	Expected Online Date
Baker Solar Center	12/31/2019
Brush Solar	10/1/2019
MC6 Hydro	7/30/2019
Morgan Solar	10/1/2019
Ontario Solar Center	12/31/2019
Vale 1 Solar	10/1/2019

In developing the forecast of PURPA expenses for the APCU, for each PURPA project (134 projects currently online or expected to come online during the 2019 APCU test year), Idaho Power Company ("Idaho Power" or "Company") multiplies the average monthly delivered generation by the applicable contract rate. The sum of the forecast PURPA contract expenses is added to the AURORA-modeled power supply expenses for the test period to produce total net power supply expense for the APCU. For new projects, such as the projects noted above, that do not have historical actual generation data, and therefore the average monthly delivered generation is not available, the Company relies on the profile of expected generation provided by the PURPA project to determine the forecast contract expense for the test period.

Additionally, for the October Update, forecast generation for new PURPA projects expected to come online during the APCU test year is annualized, meaning if a project comes online or is scheduled to come online for any month of the reporting period, it is assumed the project will be online for all months of that reporting year. This process has been utilized since the APCU mechanism was implemented in order to establish a base or normalized level of PURPA expense to be included in base rates.

For the March Forecast, forecast generation for new PURPA projects expected to come online during the APCU test year is included beginning in the month in which the project is expected to come online. Furthermore, the expected online date for any new PURPA project is adjusted using a three-year average Contract Delay Rate of historical PURPA projects. This process has been utilized since the 2018 APCU per the settlement stipulation approved in Order No. 18-170.

STAFF'S DATA REQUEST NO. 12:

Please explain in narrative form, the rationale for requiring re-pricing of the AURORA model. Does IPC believe any of the factors leading to the re-pricing requirement have changed since that time?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 12:

The re-pricing of AURORA-generated volumes of purchased power and surplus sales with a forward-based price curve using the Mid-Columbia ("Mid-C") hub is based on a proposal made by Staff and accepted by the Public Utility Commission of Oregon ("Commission") in Docket No. UE 167. In that docket, Staff claimed that, "Idaho Power's AURORA modeling does not reasonably reflect the relationship between Northwest hydro conditions and Northwest natural gas and electricity market prices." Consequently, Staff made the recommendation to replace the AURORA-modeled market electricity prices with a forward price curve. "The Commission should use Idaho Power's April 30, 2004 forward electricity price curves for the Mid-C hub to adjust Idaho Power's filed [Net Variable Power Costs]." Staff suggested that, "[T]hese forward market prices are more representative of the average level of spot market prices for the period rates from this docket are expected to be in effect, than the modeled market-clearing prices . . . ." The Commission accepted Staff's recommendation in Order No. 05-871.

Order No. 05-871 also directed the parties to work together to consider whether there is a more effective regulatory mechanism for Idaho Power to recover its allowable power costs. Following that Order, the Company filed its request for a power cost adjustment mechanism ("PCAM"). The result of that filing was a settlement stipulation approved by the Commission in Order No. 08-238, Docket No. UE 195, establishing the APCU and implementation of the PCAM, or the annual power supply expense true-up. The settlement stipulation prescribes a methodology for determining normalized net power supply expenses for the APCU October Update comparable to the methodology adopted by the Commission in Order No. 05-871. Per the settlement stipulation, the output of the AURORA model will be used to determine the net power supply average dispatch for normal loads and average streamflow conditions, and the wholesale electric prices for purchased power and surplus sales determined by the AURORA model will be replaced with an average forward electric price curve (Docket No. UE 195, Stipulation, p. 3). Although the Company continued to question the repricing of AURORA-modeled power purchases and sales, it agreed to the repricing methodology for settlement purposes.

CASE: UE 350
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203
WORK PAPERS

Exhibits in Support
Of Opening Testimony

February 4, 2019

Staff Exhibit 203 is confidential and is subject to

UE 350 Protective Order No. 18-429.

CERTIFICATE OF SERVICE

UE 350

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 4th day of February, 2019 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763

UE 350 – SERVICE LIST

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