Puget Sound Energy
Docket UE-200980 - Energy Imbalance Market Collaborative
Summary Report - November 2021

Introduction

In Puget Sound Energy's (PSE) 2020 power cost only rate case (PCORC), parties to the full multi-party settlement that was approved by the Washington Utilities and Transportation Commission (Commission) reached a compromise on how to treat the costs and benefits associated with the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM). The settlement narrative describes that compromise this way:

> "With respect to the revenue deficiency in this case, the Settling Parties agreed to reduce the cost of market purchases in variable power costs by an agreed-to amount for EIM benefits of $8.0 million and to include $3.9 million for EIM costs in the fixed production costs in this case. The net effect of this adjustments is a reduction of revenue deficiency by $4.4 million."[1]

The parties also agreed to "participate in a collaborative workshop on the estimation and treatment of EIM costs and benefits for rate making purposes."[2]

As a result of this agreement, PSE led a series of five two-hour workshops that included representatives from Commission Staff, Alliance of Western Energy Consumers (AWEC) and Public Counsel. These workshops were held virtually on June 15, July 21, August 4, August 16 and September 17, 2021. The first three workshops included analysts and counsel, and the second two workshops included only analysts.

The content of the series of workshops was the following:

1. Objectives and principles of the collaborative
2. Existing benefit estimates and PSE's current approach to modeling power costs
3. Proposed approach to including the impact of EIM participation in current power cost models using sub-hourly modeling
4. Detailed discussion with analysts
5. Follow up discussion with analysts.

PSE provided slide presentations for workshops 1, 2, 3 and 5 to all participants. These presentations are included as Appendices 1-4 to this report.

Workshop 1

PSE provided an overview of the EIM that included the following information.

- PSE must constantly balance resources and load:
    - Energy purchases and sales are made bilaterally in the term, day-ahead and hour-ahead markets

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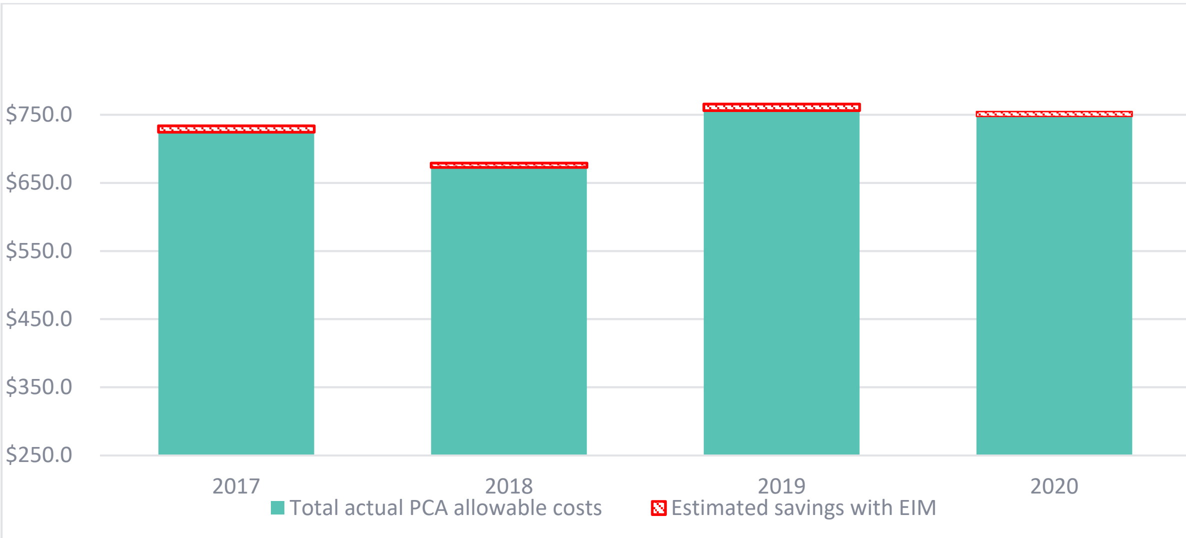
[1] Docket UE-200980 Joint Settlement Narrative in Support of Settlement Stipulation and Agreement, paragraph 12

[2] Docket UE-200980 Settlement Stipulation and Agreement, page 6

    - PSE holds operating reserves and contingency reserves (available generation capacity) going into each hour
    - Prior to EIM participation, PSE used only its own generating resources to balance generation and load within the hour.
- EIM is a sub-hourly wholesale energy market that enables purchases and sales in 15-minute and 5-minute increments.
- The EIM is one type of organized market:
    - Organized wholesale markets can include both day-ahead and real-time markets
    - In the western United States, excluding CAISO, day-ahead and hourly markets include only bilateral transactions whereas the EIM is a sub-hourly organized market.
- The bilateral market is limited:
    - Bilateral transactions limit resource optimization because transactions are between individual counterparties rather than a larger load and resource base
    - Volumes are fixed for blocks of hours for day ahead transactions (peak and off peak) and full hours for real time transactions.
- EIM enables more optimal sub-hourly energy supply:
    - EIM allows PSE to purchase from or sell to other market participants to maintain its load/resource balance and optimize available resources every 15 and 5 minutes within the hour
    - CAISO uses a market wide economic dispatch model and participant-submitted data to find the lowest-cost energy to serve real-time demand
    - Diversity of load and resources across the wide geographic area provides for integration of variable resources and more efficient balancing of supply and demand inside the hour.
- Sub-hourly operations are different with the EIM:
    - Before PSE entered the EIM, the hour-ahead process included unit commitments, hourly dispatch and bilateral deals. With the EIM, the hour-ahead process includes these things and submission of hourly base schedules to CAISO
    - Before PSE entered the EIM, within each hour PSE's load office adjusted resources to maintain load-resource balance. With the EIM, CAISO optimizes resource dispatch throughout the EIM footprint while PSE's load office retains ultimate balancing responsibilities, balancing load and resources moment-to-moment and meeting reliability requirements for the Balancing Authority Area (BAA).
- PSE must continue to meet hourly requirements:
    - PSE continues to purchase and sell in the term, day-ahead and hour-ahead markets. These bilateral transactions, combined with the planned dispatch of PSE resources, equal forecasted PSE load going into each hour. This hourly load/resource balance becomes PSE's EIM base schedule.
    - PSE begins each hour with resources sufficient to serve forecasted load
    - PSE must hold sufficient flexible ramping capability and reserved capacity. These requirements ensure entities are able to meet load and reliability obligations without leaning on other participants.
- CAISO-estimated EIM benefits indicate up to a one percent reduction to PSE's actual variable power costs:

- PSE's actual power costs in the Power Cost Adjustment (PCA) were approximately one percent lower than they might have been in 2017 through 2020 without EIM participation as depicted in Figure 1, based on CAISO-estimated benefits.
- PCA sharing bands determined how much of this benefit was assigned to customers.

Figure 1: Actual allowable PCA power costs and estimated impact of EIM participation ($ in millions)[3]



The first workshop also included a discussion of the objective of the collaborative and the final work product. The group agreed that the objective is to "agree on a method to quantify and account for the net impact of EIM participation in PSE's rate year power cost forecasts."

PSE proposed the following principles for treatment of the EIM in PSE's rate year power cost forecasts:

1. The net impact of EIM participation should be reflected in customer rates
2. The approach to incorporating EIM should be consistent with established ratemaking principles as applied to PSE, recognizing that the assumptions and approach to power cost modeling can evolve over time
    a. Power cost projections should accurately represent rate year power costs[4]
    b. Normal conditions for load, hydro and wind
    c. Fundamentals-based power price forecast
    d. Rate year power costs are established on a forward-looking basis
3. Time and effort should be commensurate with the scale of costs and benefits.

There was a comment from the group that it was early in the collaborative process to preclude the possibility of using a backward-looking approach to incorporating EIM benefits.

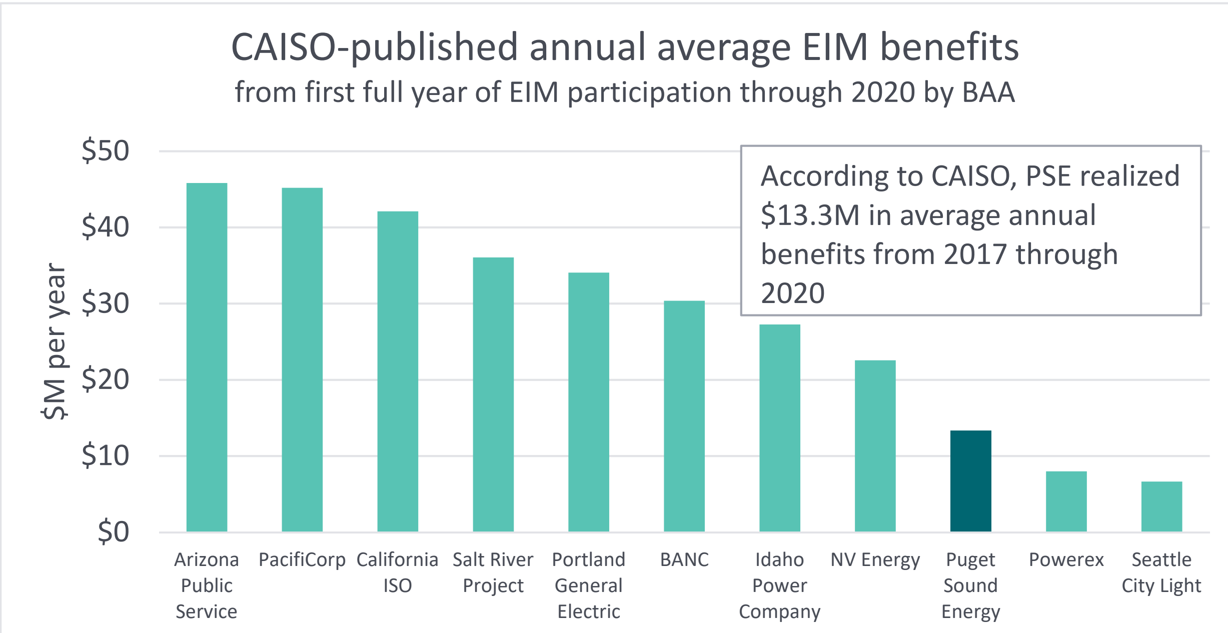
[3] CAISO benefits estimates include O&M savings, which are not included in PCA power costs. Estimated EIM power cost reductions shown here are therefore likely higher than actual savings.
[4] *See* WUTC v. Puget Sound Energy, Dockets UE-111048 & UG-111049, Order 08 (May 7, 2012) at n.303

Workshop 2

The Western EIM connects multiple BAAs in a voluntary real-time energy market serving 14 BAAs. A BAA is responsible for reliably planning and operating an area of the high voltage grid according to federal standards. All BAAs balance supply with demand in real time.

EIM participation benefits power consumers across the West. Figure 2 presents CAISO's estimates of average annual EIM benefits for each market participant.

Figure 2: CAISO-published average annual EIM benefits ($millions)



CAISO uses a counterfactual approach to estimate the benefits of EIM participation:

- The counterfactual dispatch meets the same amount of real-time load imbalance in each BAA *without* EIM transfers between neighboring EIM BAAs
- Real-time load imbalance is the difference between sub-hourly net load and hourly base schedule
- The benefit can take the form of cost savings or net revenues or their combination
- EIM benefit = counterfactual dispatch cost – net EIM participation cost, as described below.

Net EIM participation cost is made up of four components:

- Net participation cost = redispatch cost + net transfer cost + net greenhouse gas (GHG) cost + net flex ramp cost
- Redispatch cost is the difference between counterfactual and EIM dispatch costs
- Net transfer costs are payments for optimized transfers of energy between BAAs and can be positive or negative
- GHG and flexible ramp contribute to EIM benefits on a smaller scale
    - o GHG benefits derive primarily from hydro or wind exports being designated as having flowed to CAISO

- Flex ramp transfers are payments for imports or exports of flexible ramping capacity reserved to handle intra-hour load and generation uncertainties. Flex ramp benefits are not material for PSE.

CAISO benefits estimates should not be interpreted as direct reductions to power costs for three reasons:

1. They are calculated at the BAA level so include third party (non-utility) loads and generation resources, e.g., Microsoft, Green Direct[5], non-utility generators
2. They assume resource bids are equal to actual costs. This is a faulty assumption with respect to hydro resources, because hydro has no incremental power costs. Hydro bids in the EIM are used to communicate operational considerations and opportunity costs, but do not represent actual costs. Bids also include non-fuel resources costs such as variable operations and maintenance expenses, which are not included in power costs
3. They are measured against base schedules, which may be sub-optimal due to bilateral market inefficiency.

PSE uses SettleCore software to validate that CAISO's estimate of PSE's EIM benefits is consistent with CAISO's defined method. SettleCore downloads raw data directly from CAISO and applies algorithms to the raw data to replicate CAISO's benefits calculation.

PSE's EIM hydro bids can skew CAISO's estimates of EIM benefits, because PSE's EIM bids for hydroelectric resources are sometimes used to manage reservoir storage levels. PSE adjusts the CAISO estimates using its SettleCore benefits model by substituting next-day ICE Mid-C peak prices for actual EIM hydro bids, without adjusting the economic merit order. In 2018 this adjustment resulted in a downward revision of $6.3 million in EIM benefits relative to CAISO's version.

Other utilities in the Northwest recognize the shortcomings of CAISO's methodology and have developed different approaches to reflecting EIM impacts in customer rates.

- PacifiCorp projects future benefits based on historical relationships using regression analysis, with benefits modeled as a function of market prices and transfer capability, and adds GHG benefits
- Portland General Electric adjusts forward-looking hourly model results to include estimated EIM transactions and adds GHG using forward carbon prices
- In Oregon, Idaho Power replicates the CAISO method using SettleCore and adjusts for hydro bids
- In Idaho, Idaho Power excludes EIM adjustments from power cost projections because annual rate changes include recovery of deferred costs including EIM impacts.

PSE uses the Aurora model to forecast power costs, optimizing the portfolio on an hourly level. Model inputs are based on normal conditions, and the model has perfect foresight for load and variable resource generation, so there is no uncertainty or variability. Since the 2019 general rate case (GRC) the cost of holding reserved capacity and flexibility has been included, but resources are never deployed in the model to actually respond to within-hour changes. The current model stops short of sub-hourly

[5] Green Direct is technically not a third party load, but is treated as such for power cost ratemaking.

operations[6], but there are costs associated with sub-hourly balancing. Actual load and resource volumes change constantly, rather than being flat for an entire hour as modeled. Without the EIM, these changes must be followed using only PSE's resources. Limitations of using only PSE's resources include:

- Dispatchable resources operate at less than optimal output to follow variations
- Additional, more expensive resources may need to be dispatched to meet within-hour peaks (which don't show up on an hourly average basis)
- Such resources may need to continue to run out-of-the-money due to minimum run times or physical operating constraints
- Hydro may need to be spilled or wind curtailed to make room for now running uneconomic resources.

With the EIM, imports and exports can be used to follow load and resource changes.

Workshop 3

PSE proposes an approach to including the impacts of EIM participation in rate year power costs. The proposed approach uses the Aurora model to calculate sub-hourly balancing costs and benefits of the EIM:

- Current PSE modeling at the hourly level does not capture the within-hour balancing costs against which EIM benefits are measured
- The Aurora model can be run at sub-hourly intervals to estimate the cost of balancing PSE load and variable resource output within each hour, both with and without access to a sub-hourly market
- The sub-hourly model without a market estimates what PSE's portfolio cost would be if PSE did not participate in the EIM
- The sub-hourly model with a market estimates PSE's portfolio cost including benefits of EIM participation.

The proposed Aurora approach is conceptually similar to the CAISO benefits calculation:

- The sub-hourly model without a market is analogous to the counterfactual dispatch cost used in CAISO's benefits estimates. It includes costs of following sub-hourly load and resource imbalances using only PSE's resources
- The sub-hourly model with a market is analogous to the net EIM participation cost used in CAISO's benefits estimates. It includes benefits of using lower cost market resources to follow imbalances and benefits from sales of surplus generation in sub-hourly intervals, but it does not include net GHG revenue, which will need to be accounted for outside the model
- EIM benefit = portfolio cost without sub-hourly market – portfolio cost with sub-hourly market + GHG benefit.

Assumptions and inputs in hourly model are mostly identical to those used in PSE's 2020 PCORC:

- Load and variable resource inputs are based on normal conditions

[6] See slide 24 from Workshop 2 in Appendix 2 for a graphical depiction of market time frames and PSE's load/resource balancing activity relative to the current hourly modeling approach.

    - Hourly values for entities/resources throughout the WECC are from Aurora database
    - Hourly values for PSE are monthly forecasts shaped using hourly profile from the Aurora database
    - The model has perfect foresight of load and variable resource outcomes.
- Hourly power prices are from the optimized dispatch of resources in the WECC-wide model
    - Modeled prices for northwest region represent Mid-C market prices
- Monthly hydro energy volumes are average volumes from 80 historical years
    - In PSE's 2020 PCORC each of the 80 years was modeled separately and average model results were used in power cost forecast.

Additional assumptions and inputs are needed for sub-hourly models:

- Sub-hourly load and wind inputs are interpolated from same normal values in the hourly model. On average sub-hourly outcomes are identical to hourly values used to establish base schedules
- Sub-hourly power prices are from the optimized dispatch of resources in a sub-hourly WECC-wide model
    - Modeled prices for northwest region represent EIM prices at PSE's system
    - Implicit assumption that all WECC entities are EIM participants
- PSE's market purchases and sales from the hourly model are an input to sub-hourly models. These transactions represent bilateral market transactions included in PSE's hourly base schedules.

The simplified hydro assumption is necessary to manage model run times and output data:

- Current forecasts use average results from 80 individual scenarios (one for each year in the historical hydro data set). This requires 160 model runs in the current hourly modeling approach
- Proposed sub-hourly modeling approach includes three additional model runs for each scenario. This would require 400 total model runs to do each hydro year individually
    - Additional runs are in 15-minute intervals, requiring four times as much run time and generating four times more output data to process than the hourly model
    - Proposed approach includes five total runs with average hydro to manage run time
- Avista used median hydro as model input in its 2020 GRC[7] per Energy + Environmental Economics (E3) recommendation. E3 reviewed hydro forecast methodologies of seven utilities and PSE is the only one modeling more than one hydro scenario.

GHG benefits must be estimated outside the Aurora model. In the short run, a simple average of historical GHG net benefits provides a reasonable estimate of expected future benefits. This issue should be revisited because the amount of GHG benefits may change with increased compliance with Washington's Clean Energy Transformation Act (CETA).

PSE tested the proposed approach using its Aurora model from the 2020 PCORC, for the rate year ending May 2022. The sample results rely on the same natural gas prices and portfolio inputs used in PSE's supplemental filing. The analysis only included the portion of power costs that are calculated using Aurora. Remaining costs of approximately $271 million are fixed costs that do not vary materially based

[7] Docket UE-200900, Exh. CGK-1T and CGK-8

on model output. The proposed approach estimates EIM benefits of $13.5 million for the PCORC rate year as depicted in Figure 3.

Figure 3: Summary of Estimated Rate Year EIM Benefits

The proposed sub-hourly model produced the following results:

- Average sub-hourly market prices align with hourly prices, with increased volatility in the sub-hourly market
- Natural gas-fired peaking units generate more and operate at more efficient output levels with a sub-hourly market, resulting in a lower average cost. Combined cycle gas resources have similar but less pronounced results
- Wind generation is about 1.9 percent higher with a sub-hourly market due to fewer curtailments
- The higher generation from thermal and wind resources drives sub-hourly market sales revenue.

The net impact of including EIM in PSE's power cost forecast is less than estimated EIM benefits, because the sub-hourly model includes costs of sub-hourly operations that were excluded in the hourly model. Using the PCORC model, these sub-hourly costs total $5.9 million. The combined impact of sub-hourly costs not previously modeled and EIM benefits is a power cost reduction of $7.6 million, as depicted in Figure 4.

Figure 4: Net Impact of Sub-hourly Model with EIM on Variable Power Costs

When $3.9 million of fixed EIM labor and administrative costs are included, the net impact of including the EIM in the forecast is a $3.6 million reduction to power costs. This compares to the $4.1 million benefit included in the 2020 PCORC settlement.

In summary, PSE's proposed approach combines a new sub-hourly Aurora model with the existing hourly model to calculate portfolio costs at the sub-hourly level including the re-dispatch and transfer revenue benefits of EIM participation. The sub-hourly results become the Aurora model costs used for PSE's power cost forecasts. An additional sub-hourly model run can be used to calculate portfolio costs without the EIM solely to identify the EIM benefits that are included in the sub-hourly model with the EIM. Average actual GHG benefits based on recent available data are deducted from power costs. Test year actual EIM-related costs charged to FERC account 557 are included in fixed power costs.

Workshop 4

The purpose of the August 16 workshop was to provide analysts in the collaborative the opportunity to explore the proposed sub-hourly model in more detail than had been provided on August 4. PSE opened the Aurora model and walked through the sections of the model that were altered in order to calculate sub-hourly EIM impacts. That included:

1. Sub-hourly wind inputs that are interpolated from hourly values
2. Sub-hourly load being automatically interpolated by the model
3. Table where market transmission is reduced in the “with market” run and market transmission is removed for the “without market” run
4. Other high level model settings (run period, solve every 15 minutes, etc.).

There was discussion about sub-hourly interpolation. Participants suggested that the use of interpolation to estimate sub-hourly wind shapes might not adequately represent wind variability and might not lead to an accurate representation of EIM benefits. Participants suggested exploring the use of historical wind data to develop sub-hourly wind shapes. PSE could do this for PSE’s wind resources, and if it looks like a reasonable approach, the next step would be to determine how to estimate wind shapes for other resources in the region.

PSE agreed to examine historical wind data for PSE’s resources, develop new wind shapes, and estimate the impact on modeled EIM benefits and report back to the group.

PSE also opened a spreadsheet that contained summary outputs of model runs with and without the market. This spreadsheet was sent to participants after the meeting so they could examine the results. The file includes:

- Cost and energy output from the hourly modeling using average hydro as an input, summarized by month
- Cost and energy output from the sub-hourly model with a sub-hourly market summarized by month
- Cost and energy output from the sub-hourly model without a sub-hourly market summarized by month
- Aurora-generated power prices from the hourly pricing model
- Aurora-generated power prices from the sub-hourly pricing model.

Workshop 5

The purpose of the September 17 workshop with analysts was to follow up on suggestions made by participants at the August 16 workshop regarding how to approach the sub-hourly shaping of wind generation in the sub-hourly model. The agenda was:

1. Review PSE’s approach for shaping wind sub-hourly
2. Discuss alternative approach using historical data
3. Consider impact of historical sub-hourly wind shapes on portfolio costs and EIM benefit estimate
4. Touch on hydro assumption required for sub-hourly model.

There was discussion of the two alternatives for shaping sub-hourly wind data. Use of historical data to develop wind shapes resulted in a marginally lower level of EIM benefits. PSE suggested that the difference in benefits was not material enough to warrant the added complexity of using historical data and continued to recommend its proposed interpolation approach.

There was also a discussion of the need to use average or median hydro as an input to the model rather than running the model separately for every year of the historical hydro record, and analysts expressed general support for that plan.

Collaborative analysts requested additional data for their review. PSE made the following data available to them via a file sharing service on September 21:

- Historical EIM prices
- Sub-hourly market prices used in the sub-hourly analysis based on interpolated wind shapes (PSE proposal) and historical wind shapes.
- Sub-hourly wind inputs
- Sub-hourly dispatch results.

Conclusion

At the first collaborative meeting, the group agreed that the objective was to “agree on a method to quantify and account for the net impact of EIM participation in PSE’s rate year power cost forecasts.” To advance that objective, PSE hosted five meetings, provided the information described in this document, and facilitated discussion among participants.

In summary, the material included:

- An overview of the EIM and how it fits into the context of PSE’s operations
- An explanation of CAISO’s calculation of EIM benefits
- Descriptions of the approaches taken by three other utilities in the Pacific Northwest to incorporating the impact of the EIM in their customer rates, with references to source documents
- A review of PSE’s current method for projecting rate year power costs
- A proposed approach to extend PSE’s existing models to sub-hourly intervals to incorporate the impacts of EIM participation, with information on the financial impacts based on rate year power costs from the 2020 PCORC
- A large volume of data for review by analysts.

The collaborative parties agree that the approach to incorporating EIM impacts on rate year power costs described in this report is a reasonable method for quantifying and accounting for the net impact of EIM participation in PSE’s rate year power cost forecasts.

This approach combines a new sub-hourly Aurora model with the existing hourly model to calculate portfolio costs at the sub-hourly level including the re-dispatch and transfer revenue benefits of EIM participation. The sub-hourly results become the Aurora model costs used for PSE’s power cost forecasts. An additional sub-hourly model run can be used to calculate portfolio costs without the EIM solely to identify the EIM benefits that are included in the sub-hourly model with the EIM. Average actual GHG benefits based on recent available data are deducted from power costs. Test year actual EIM-related costs charged to FERC account 557 are included in fixed power costs.

The parties recommend use of the approach described in this report in PSE's future rate proceedings and agree that it will be used in PSE's 2022 GRC. However, this recommendation does not preclude any party from reviewing the accuracy of the calculation of PSE's projected EIM benefits in the 2022 GRC or future cases; nor does it preclude any party from proposing modifications or recommending an alternative approach in response to changed circumstances in future cases (after the 2022 GRC).