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Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration

October 2015

Energy+Environmental Economics

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Executive Summary

Changes in the electricity industry across the Western U.S. are creating new opportunities for cooperation and coordination among electric utilities. As populations and economies throughout the region continue to grow, utilities are increasingly looking to regional solutions to meet their customers' needs at a reasonable cost. State and federal environmental policies and changing customer preferences are driving a transformation of the region's generation mix, significantly increasing its reliance on renewable energy. Regional coordination will help Western utilities respond to these changes at a lower cost to customers while maintaining high levels of reliability.

The benefits of regional coordination have already begun to spur collaborative initiatives among the West's balancing authority areas. In November 2014, the California Independent System Operator (ISO) and PacifiCorp established a joint energy imbalance market (EIM). The new market generated $21 million in customer benefits in the first eight months of operation, in line with initial estimates. NV Energy is on schedule to begin participating in the EIM in November 2015 and two additional utilities — Puget Sound Energy and Arizona Public Service — have announced their intention to participate in the EIM in fall 2016. Portland General Electric and Idaho Power Company have both recently announced plans to explore steps to possible participation in the EIM.

In April 2015, PacifiCorp and the ISO announced a memorandum of understanding to explore PacifiCorp becoming a full participating transmission owner (PTO). As part of this process, PacifiCorp engaged Energy and Environmental Economics (E3) to preliminarily assess the potential incremental benefits[1] beyond those already captured through participation in the EIM, of further integrating PacifiCorp and the ISO, where PacifiCorp becomes a PTO and the ISO becomes a more regional organization through changes in its governance. This report presents an overview of our findings.

Full integration of the PacifiCorp and ISO systems would provide a number of operating, investment, and regulatory cost savings, incremental to those achieved by the EIM, which are summarized in the table below.

Table 1. Benefits of PacifiCorp and ISO integration incremental to the EIM (shaded rows indicate benefits quantified in this report)

Benefit Category	Brief Description
More efficient unit commitment and dispatch	Lower generation costs, from PacifiCorp's participation in the ISO's day-ahead market
Improved market pricing transparency and liquidity	Lower-cost market solutions, from nodal price signals and more liquid markets
Lower frequency response procurement costs	Lower-cost compliance with upcoming NERC requirements,[2] from load and resource diversity
Enhanced reliability	Reduced outage costs, from greater visibility and ISO ability to respond across combined footprint
More efficient overgeneration	Fuel and renewable cost savings, from lower

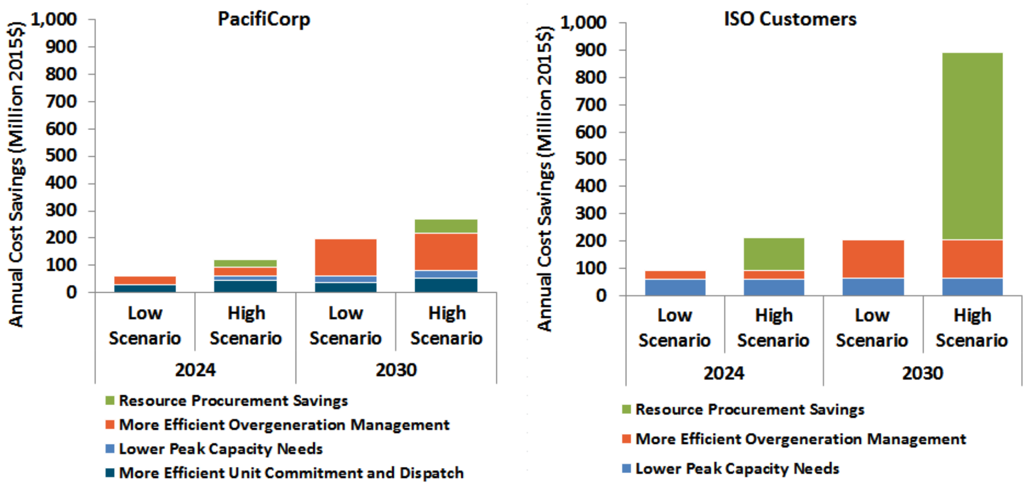
[1] This analysis focuses only on the gross benefits of PacifiCorp and ISO integration. It does not examine potential participation costs, which will be addressed separately by PacifiCorp and the ISO.

[2] NERC BAL-003-1, which goes into effect on April 1, 2016, will require balancing area authorities to meet annual frequency response obligations. More detail on the standard is available on the NERC website, http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf.

management	curtailment of renewable energy
Lower peak capacity needs	Reduced need for generation capacity to meet reliability needs, from peak load diversity
Renewable procurement savings	Lower-cost renewable procurement, from joint resource development and coordinated planning
Lower flexible capacity needs	Lower ramping capacity requirements and costs, from load and resource diversity
Coordinated transmission planning	Lower operating and investment costs, from identification of new high value transmission projects across the combined footprint
Value for capacity	To the extent integration and associated diversity of load frees up existing capacity, such capacity may have value meeting other resource adequacy requirements
Centralized regulatory compliance	Lower regulatory costs, from centralized compliance with federal regulations
Greenhouse gas emissions	Coordinated transmission planning can enable diversified renewable resource procurement, and more efficient management of renewable overgeneration, leading to reduced greenhouse gas emissions

In this report, we develop quantitative estimates for four of these benefits: (1) more efficient unit commitment and dispatch, (2) more efficient overgeneration management, (3) lower peak capacity needs, and (4) renewable procurement savings. The other benefits listed in Table 1 represent important potential sources of additional value for PacifiCorp and existing ISO customers but are more difficult to accurately quantify. Figure 1 shows a range of quantified incremental benefits for PacifiCorp and ISO customers in 2024 and 2030.

Figure 1. Annual incremental cost savings (million 2015$) to PacifiCorp and ISO customers by benefit category, low and high scenarios, 2024 and 2030



We estimate that integration of PacifiCorp and the ISO's balancing authority areas would yield significant incremental annual savings that increase over time. In 2024, we estimate incremental savings of $62 to $122 million (2015$) for PacifiCorp, rising to $200 to $272 million in 2030 (Table 2). For ISO customers, we estimate incremental cost savings of $92 to $213 million in 2024, rising to $203 to $894 million in 2030 (Table 3). Over its first full 20 years, assumed here to be 2020 to 2039, we estimate that PacifiCorp and ISO integration would yield $1.6 to $2.3 billion (2015$) in total present value incremental savings for PacifiCorp, and $1.8 to $6.8 billion for ISO customers.

Table 2. Annual savings in 2024 and 2030 incremental to EIM (million 2015$) for PacifiCorp, low and high scenarios

Benefit Category	Low Scenario 2024	Low Scenario 2030	High Scenario 2024	High Scenario 2030
More efficient unit commitment and dispatch	$31	$36	$46	$54
Lower peak capacity needs	$0	$25	$17	$25
More efficient overgeneration management	$31	$138	$31	$138
Renewable procurement savings	$0	$0	$28	$54
Total benefits	**$62**	**$200**	**$122**	**$272**

Note: Individual categories may not sum to total benefits due to rounding.

Table 3. Annual savings in 2024 and 2030 incremental to EIM (million 2015$) for ISO customers, low and high scenarios

Benefit Category	Low Scenario 2024	Low Scenario 2030	High Scenario 2024	High Scenario 2030
More efficient unit commitment and dispatch	*	*	*	*
Lower peak capacity needs	$61	$65	$61	$65
More efficient overgeneration management	$31	$138	$31	$138
Renewable procurement savings	$0	$0	$121	$691
Total benefits	**$92**	**$203**	**$213**	**$894**

** Expected to be greater than zero but conservatively not included here*

The large range in benefits for 2030, particularly for ISO customers, reflects the significant upside potential for jointly planning transmission to access low-cost renewable resources across the combined footprint, thereby creating an opportunity for California to achieve a portion of its 50% renewable portfolio standard (RPS) target at a reduced cost. This study assumes high-quality wind resource potential in Wyoming is used to meet a portion of the California RPS targets as a means to measure the benefits of joint transmission planning for renewable development strategy, recognizing that alternative transmission and supply options for renewable development exist.

As the results suggest, PacifiCorp and ISO customers will benefit differently from integration. PacifiCorp's largest source of incremental benefits will be operating cost savings — savings in fuel and energy procurement costs that result from participating in the ISO's day-ahead market and importing renewable energy when California has excess supply. ISO customers will realize incremental benefits primarily from investment cost savings — savings from procuring lower cost renewable energy and from reducing the need to replace overgeneration with additional renewable energy to meet policy goals.

Benefits increase significantly over time, particularly for ISO customers facing a 50% RPS target by 2030. Consequently, it is important for stakeholders to take a long-term perspective when evaluating the benefits of PacifiCorp and ISO integration. The high-value, longer-term savings described in this report are linked to planning and investment decisions that require long lead times and clear guidance. Importantly, PacifiCorp and ISO integration in the nearer term would provide the joint processes and certainty that enable more strategic and efficient longer-term investment decisions.

The quantified benefits for both PacifiCorp and ISO customers are sufficient to support continued progress toward PacifiCorp and ISO integration. Over a longer-term horizon, the integration of the PacifiCorp and ISO balancing authority areas would provide PacifiCorp and ISO customers greater flexibility to respond to ongoing changes in state and federal environmental policies, to develop renewable energy, and to reduce greenhouse gas (GHG) emissions at a lower cost. Additionally, the regional transmission organization created through PacifiCorp and ISO integration would lay a foundation for broader participation by other balancing area authorities in the West. While the initial benefits analysis presented in this report indicates there is an opportunity for significant benefits, ultimately, a successful integration will require PacifiCorp and the ISO customers to each have net benefits. The upcoming stakeholder process will provide the guidance for any necessary changes to the ISO tariff and inform the determination of overall costs and benefits. A description of the key cost categories, while not quantified, are included in Section 3 of this report.

The remainder of this report is organized into four sections. Section 1 provides context for the assessment, describing expected changes in the Western Interconnection over the next 15 years. Section 2 presents the benefits assessment, including qualitative descriptions of how different parties stand to benefit and quantitative estimates of a subset of those benefits. Section 3 describes cost categories. Section 4 summarizes key conclusions. A separate technical appendix describes the methods and assumptions used to develop the quantitative benefit estimates.

1 Context: Developments in the Western Interconnection

Over the next 10 to 20 years, continued growth, environmental policies, and changing customer preferences will drive significant changes in how electricity is generated, dispatched, and distributed across the Western Interconnection. These drivers will create new opportunities for cooperation and coordination among electric utilities to take better advantage of the diversity of loads and resources across the region, and to realize economies of scale in generation and transmission development.

Although many utilities in the West will not see a need for new resources in the near term, continued population and economic growth and retirements of existing generating plants will trigger the need for new generation and transmission after 2020. The population of the 11 states in the continental Western U.S. is expected to grow by 15 million persons, or 20%, from 2015 to 2030.[3] To meet longer-term growth in demand and changes in policy, many utilities are looking to regional solutions, including new interstate transmission and regional wholesale markets.

[3] These 11 states include Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada, Washington, Oregon, and California. Forecasts are from the U.S. Census Bureau, **http://www.census.gov/population/projections/data/state/projectionsagesex.html**.

At the same time, federal and state environmental policies are driving large shifts in the region's generation mix. At a federal level, the Environmental Protection Agency's (EPA's) Regional Haze Rule, Mercury and Air Toxics Standards (MATS), Coal Combustion Residuals (CCR) Rule, and Cooling Water Intake Structures (CWIS) Rule are putting pressure on utilities to retire older coal-fired units. The EPA's Carbon Pollution Standards for new power plants, finalized in August 2015, restricts development of new conventional coal-fired generation. The EPA's Clean Power Plan (CPP), also finalized in August 2015, requires CO_2 emission reductions from existing power plants and is expected to result in the need for additional renewable and natural gas-fired generation.

At a state level, RPS targets will significantly raise the share of renewable energy in the West's generation mix by 2030. Eight of the eleven states in the region have RPS requirements; Utah has a voluntary renewable portfolio goal.[4] California, which accounts for just over 30% of the West's electricity demand,[5] has passed legislation to increase its RPS target from 33% by 2020 to 50% by 2030.[6]

Above and beyond state goals, utility customers are increasingly demonstrating a preference for affordable renewable energy. Most utilities in the West offer separate retail products for renewable power, at premiums of \$0.01 to \$0.02

[4] States with RPS requirements include Arizona (15% by 2025), California (50% by 2030), Colorado (30% for investor-owned utilities and 10-20% for municipal utilities and cooperatives by 2020), Montana (15% by 2015), Nevada (25% by 2025), New Mexico (20% for investor-owned utilities and 10% for cooperatives by 2020), Oregon (25%, 10%, or 5% by 2025, varying by utility size), and Washington (15% by 2020). Utah requires utilities to meet a 20% renewable goal by 2025, if it is cost-effective.

[5] Western Electricity Coordinating Council, 2015, 2015 State of the Interconnection: Reliability, https://www.wecc.biz/Reliability/2015%20SOTI%20Final.pdf.

[6] See California Legislature, Senate Bill 350: Clean Energy and Pollution Reduction Act of 2015, Section 20, http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB350.

per kilowatt-hour (kWh).[7] PacifiCorp, for instance, has over 100,000 customers enrolled in its Blue Sky program, through which it purchases renewable energy credits for its customers for a $0.0195 per kWh premium.[8] There is also growing interest from customers to fund specific renewable energy projects through new product offerings such as community and subscriber solar programs.

In responding to these three drivers — longer-term demand growth, federal and state environmental policies, and changing customer preferences — closer coordination among utilities in planning and operations can lower costs, reduce emissions, and improve reliability. To meet longer-term demand growth and replace retiring fossil fuel plants, utilities can more efficiently use existing generation and transmission capacity throughout the region and reduce the need to build new capacity within their service territories. Utilities can also more effectively plan transmission to acquire lower cost renewables and maintain grid reliability with a much higher dependence on intermittent resources by leveraging resource and load diversity across a larger geographic footprint.

For developing and integrating renewable energy to meet state goals, federal emissions reduction targets, and customer demands, the benefits of regional coordination are increasingly clear. The EIM, in its earliest stage of operations with PacifiCorp and ISO in the market, has already demonstrated the benefits of regional coordination by delivering cost savings and enhancing renewable

[7] See U.S. Department of Energy, Buying Green Power, http://apps3.eere.energy.gov/greenpower/buying/buying_power.shtml.
[8] See PacifiCorp, Blue Sky Renewable Energy, https://www.pacificpower.net/env/bsre.html.

integration.[9] EIM benefits are expected to increase as other utilities join the EIM and as additional renewables are installed in the western U.S. The need for more renewables across the western U.S. dramatically increases the opportunity for customer benefits in both the EIM and in a more integrated regional ISO. The Western Interconnection has some of the highest quality wind and solar resources in the U.S. Many of the best resources, however, are located in areas that are far from load centers and require new transmission to access them. Regional development of renewable resources and the transmission to deliver them across multiple jurisdictions can lower costs, as shown in a 2008 study for the Western Electricity Industry Leaders (WEIL) Group.[10]

Additionally, a number of studies of the Western Interconnection have indicated that a regional approach to system operations — through regionally optimized dispatch of generators and scheduling of transmission — can reduce the costs of integrating renewable energy.[11] More coordinated operations can allow aggregation of larger and more diverse loads, solar and wind resources, and dispatchable resources across multiple balancing authority areas. This aggregation helps address two challenges associated with higher penetration of solar and wind generation: (1) the need to ramp dispatchable generation resources up and down to follow solar and wind output; and (2) the frequency

[9] See California ISO, 2015, *Benefits for Participating in EIM*, July 30, 2015, http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ2_2015.pdf

[10] E3, 2008, *Load-Resource Balance in the Western Interconnection: Towards 2020*, **https://ethree.com/documents/E3_WEIL_Complete_Study.pdf**.

[11] See, for instance, GE Energy, 2010, *Western Wind and Solar Integration Study: Executive Summary*, **http://www.nrel.gov/docs/fy10osti/47781.pdf**; Michael Milligan, Brendan Kirby, and Stephen Beuning, 2010, *Combining Balancing Areas' Variability: Impacts on Wind Integration in the Western Interconnection*, **http://www.nrel.gov/docs/fy10osti/48249.pdf**; E3, 2014, *Investigating a Higher Renewable Portfolio Standard in California*, **https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf**.

and severity of overgeneration conditions, when solar and wind generation exceeds the grid's capacity to absorb it.

The potential benefits of regional coordination have already begun to spur greater integration among balancing authority areas across the West. In November 2014, the ISO and PacifiCorp established the EIM. The EIM is a real-time market with a centralized five-minute dispatch across participating balancing authority areas, enabling more flexible use of generators on a sub-hourly timescale across a large geographic footprint. NV Energy is on schedule to begin participating in the EIM in November 2015. Puget Sound Energy and Arizona Public Service are scheduled to join in fall 2016. Portland General Electric and Idaho Power Company have both recently announced plans to explore steps to possible participation in the EIM.

The EIM is an important initial step toward more coordinated operations among balancing area authorities in the West and remains a strong standalone value proposition. Beyond the EIM and its real-time market, however, there are opportunities to create significant additional value for customers by extending cooperation and coordination among the West's utilities to day-ahead markets, resource procurement, and transmission planning. PacifiCorp's integration with the ISO would represent an important move toward this more collaborative paradigm.

2 Benefits Assessment

2.1 Identification of Benefits

Integration of the PacifiCorp and ISO balancing authority areas would lead to a number of operating, investment, and regulatory cost savings incremental to the EIM. These savings are enabled by different aspects of integration.

+ ***Operating cost savings*** include lower fuel costs, renewable curtailment costs, and outage costs. These savings are enabled by the more efficient and reliable use of generation and transmission that comes from operating as a single system rather than two separate systems.
+ ***Investment cost savings*** include lower generation procurement and transmission costs, which are enabled by the ability to plan for the generation and transmission needs of the joint PacifiCorp-ISO system, rather than the needs of each separate system.
+ ***Regulatory cost savings*** include the lower cost of complying with federal energy regulations, which are enabled by PacifiCorp and the ISO's ability to comply as a single combined entity rather than as separate entities.

Table 4 lists expected savings and benefits, organized around these three categories.

Table 4. Benefits of PacifiCorp-ISO full integration
(shading indicates benefits that are quantified in this report)

Savings Category	Benefit Category	Description
Operating	**More efficient unit commitment and dispatch**	PacifiCorp's participation in the ISO's day-ahead market will provide lower-cost unit commitment and dispatch solutions, enabling efficiency gains incremental to those achieved with the EIM.
	Improved market pricing transparency and liquidity	PacifiCorp's participation in the ISO's day-ahead market will increase transparency of locational prices throughout the West and facilitate improved trading; the addition of PacifiCorp generators will also increase liquidity in the ISO's day-ahead market.
	Lower frequency response procurement costs	The combined PacifiCorp-ISO system may reduce the quantity and cost of frequency response resources required for balancing authorities to comply with NERC BAL-003-1 requirements, effective beginning in 2016.
	Enhanced reliability	By combining operations, the ISO will have real-time visibility and greater ability to identify and respond to emergency conditions across the combined footprint, reducing the number and duration of power outages.
	Greenhouse gas emissions	Coordinated transmission planning can enable diversified renewable resource procurement, and more efficient management of renewable overgeneration, leading to reduced greenhouse gas emissions
Operating / Investment	**More efficient overgeneration management**	Full coordination of import and export schedules through a centralized day-ahead market will allow the combined PacifiCorp-ISO system to respond more flexibly to renewable overgeneration, reducing the need for renewable resource curtailment.
Investment	**Lower peak capacity needs**	PacifiCorp and the ISO customers can plan capacity for meeting the combined system's coincident peak load, which is lower than the sum of their non-coincident peak loads as separate entities.
	Renewable procurement savings	Full coordination can facilitate lower cost procurement of renewable resources and joint procurement of new transmission across the combined footprint, creating investment cost savings for both PacifiCorp and ISO customers.
	Lower flexible capacity needs	Due to load and resource diversity, the maximum three-hour ramp required for the combined PacifiCorp-ISO system is lower than the sum of maximum ramps they require as standalone entities, reducing total flexible capacity needs.
	Coordinated transmission planning	Joint transmission planning will allow identification of new regional transmission projects, in addition to renewable energy-driven projects,

		that increase operating and investment cost savings.
	Value for capacity	To the extent integration and associated diversity of load frees up existing capacity, such capacity may have value meeting other resource adequacy requirements.
Regulatory	**Centralized regulatory compliance**	Integration will allow PacifiCorp and the ISO to comply with federal regulations as a single entity, increasing efficiency and reducing costs relative to separate compliance.

We developed quantitative estimates for four of the benefit categories described in Table 4: (1) more efficient unit commitment and dispatch, (2) more efficient overgeneration management, (3) lower peak capacity needs, and (4) renewable procurement savings. The benefits not quantified in this study may represent significant value to both PacifiCorp and ISO customers, but are more difficult to accurately quantify.

In addition, integration of the PacifiCorp and ISO systems will provide a path to a lower carbon future both within and outside of California when compared to what each individual entity could achieve on its own. Although a full accounting of emission reductions from PacifiCorp-ISO integration is beyond the scope of this report, we qualitatively describe key ways in which it leads to lower emissions.

2.2 Description of Quantified Benefits

2.2.1 MORE EFFICIENT UNIT COMMITMENT AND DISPATCH

There are a number of barriers to efficient trade of electricity across balancing areas in the West, including separate unit commitment and dispatch, "pancaked" transmission rates and losses,[12] and illiquid, non-transparent markets. Centralizing system operations across multiple balancing areas can eliminate these barriers, making more efficient use of generation and transmission and lowering production costs.

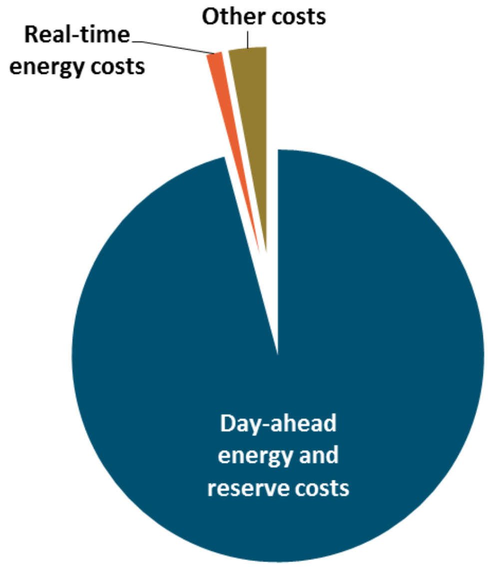
For PacifiCorp and the ISO, the EIM is already eliminating some barriers to trade. However, the EIM only covers real-time imbalance energy — optimizing least-cost dispatch of generation to respond to real-time changes in loads and resources. In an integrated PacifiCorp-ISO system, PacifiCorp's participation in the ISO's day-ahead market will enable three main efficiency improvements incremental to the EIM: (1) optimal unit commitment, resulting in fewer conventional generator starts and lower startup costs; (2) day-ahead nodal dispatch, resulting in lower transmission congestion and re-dispatch costs; and (3) co-optimized energy and ancillary services, resulting in lower energy and ancillary service costs. These improvements translate to customer savings through reductions in utilities' cost of generating and procuring energy for their customers.

The relative size of the ISO's day-ahead and real-time markets suggests that significant incremental value is available from PacifiCorp's participation in the day-ahead market, relative to participating in the EIM alone. From 2009 to 2013, day-ahead energy and operating reserve costs represented 93% to 96% of

[12] Pancaked transmission rates and losses occur when transmission customers are charged separate, layered access and loss fees by multiple transmission owners to move power across multiple balancing areas, resulting in high transmission costs for long-distance transactions.

the ISO's total wholesale energy costs, while real-time energy costs accounted for 1% to 3% (see Figure 2).[13]

Figure 2. Share of day-ahead energy and reserve costs, real-time energy costs, and other costs in the ISO's total wholesale energy costs, 2013[14]



The incremental benefits of PacifiCorp's participation in the ISO's day-ahead market, in addition to savings from the EIM, are difficult to assess. As an alternative to statistical analysis or detailed production simulation modeling, we draw on the experience of other regions, including the Southwest Power Pool

[13] The real-time energy market can result in incremental or decremental dispatch changes relative to the day ahead, so real-time transactions typically comprise a higher percentage share of total transaction volume than of total wholesale energy costs. Real-time transaction volumes, however, are still considerably smaller than day-ahead transactions.

[14] Other costs include bid cost recovery costs, reliability-must-run and capacity procurement mechanism costs, and the ISO's grid management charge. Data are from California ISO, 2014, *2013 Annual Report on Market Issues & Performance*, **https://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf**.

(SPP) and Midcontinent Independent System Operator (MISO), to estimate benefits for this report.[15] We only estimate unit commitment and dispatch savings for PacifiCorp, as PacifiCorp is likely to see larger changes in operations than the ISO. However, it is likely that ISO customers will also realize savings from opportunities for more efficient day-ahead transactions with resources located in PacifiCorp's service area.

2.2.2 LOWER PEAK CAPACITY NEEDS

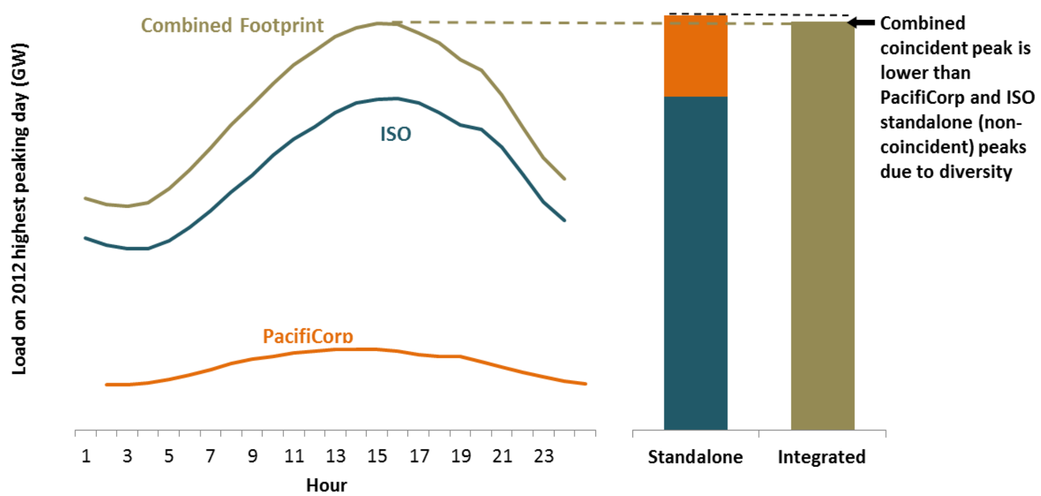
Currently, resource adequacy obligations require PacifiCorp and ISO customers to build or contract for local resources to meet their own individual system peak loads plus a planning reserve margin. With an integrated system, PacifiCorp and ISO customers can instead plan capacity to meet the combined system's peak load, plus any local capacity requirements resulting from transmission constraints. Because PacifiCorp's peak load occurs during different hours than that of the ISO system, the coincident peak demand for the combined PacifiCorp-ISO system will be smaller than the sum of the non-coincident peaks for the two systems operating separately. As a result, the peak generation capacity required to serve the combined system peak is lower, leading to capacity cost savings and lower costs to customers.

Figure 3 illustrates this peak load diversity benefit for a single year. Due to geography and different weather conditions, peak demand in PacifiCorp's service territory typically occurs earlier in the day, and often in a different day or month, than peak demand in the ISO. As a result, the coincident peak demand of the combined PacifiCorp-ISO system is lower than the peak demands of the

[15] PacifiCorp and the ISO will consider if additional analysis is necessary as policy and costs are further developed.

two standalone systems, as the bars on the right-hand side of the figure illustrate.

Figure 3. Illustration of peak capacity savings from PacifiCorp's integration with the ISO [16]



Peak capacity savings can be expressed using a coincidence factor — the ratio of each entity's coincident peak demand under the combined system to its non-coincident peak demand as a standalone entity — with savings adjusted for transmission constraints.[17] A lower coincidence factor implies less coincidence with the combined system peak load, and an entity with a lower coincidence factor will generally realize larger peak capacity savings as part of the combined system. Based on historical data, we estimate that PacifiCorp's coincidence factor is significantly lower than the ISO's because the combined coincident

[16] Data are from FERC Form 714 for PacifiCorp and the ISO footprint.

[17] More formally, peak capacity savings for each entity i are calculated as

$$PCS_i = NCP_i \times \left(1 - \frac{CP_i}{NCP_i}\right) \times (1 + PRM_i)$$

where PCS_i is peak capacity savings for entity i, NCP_i is entity i's non-coincident peak load, CP_i is entity i's coincident peak demand, $CP_i./NCP_i$ is the coincidence factor, and PRM_i is entity i's planning reserve margin.

peak demand typically occurs much closer to the ISO's standalone peak demand. For PacifiCorp, potential capacity cost savings are limited by transmission constraints, assumed here to be 776 MW.[18]

Actual savings will depend on planning and regulation practices in the PacifiCorp and ISO regions. For PacifiCorp, capacity savings will be realized as new thermal resources in its integrated resource plan are displaced. Recognizing that the timing of new resource needs is uncertain, we use a range of scenarios for calculating peak capacity savings for PacifiCorp customers. In a high benefits scenario, we assume new thermal resources are displaced beginning in 2024. In a low-benefits scenario, we assume new resources will not be displaced until 2028.

In the nearer-term, PacifiCorp may also realize cost savings from selling capacity freed up by peak load diversity into California's resource adequacy (RA) market. This new revenue source would reduce costs to PacifiCorp customers. The amount of incremental capacity that would be available for sale in California is uncertain at this time, as are the RA contract prices that would result. These potential nearer-term benefits are therefore not quantified in this report.

For the ISO, customers realize capacity savings in the first year of integration, as utilities have lower RA requirements and are required to sign fewer RA contracts. The value of these savings increases over time, as the ISO system

[18] For this analysis, transfer capability assumptions were based on the amount of transmission rights currently held by PacifiCorp. However, it is possible that additional transfer capability may be available in an integrated PacifiCorp-ISO system. For instance, coordinated transmission planning could significantly increase the transfer capability between the two systems.

approaches load-resource balance — assumed here to occur in 2024 — and capacity prices rise to the net cost of new entry.

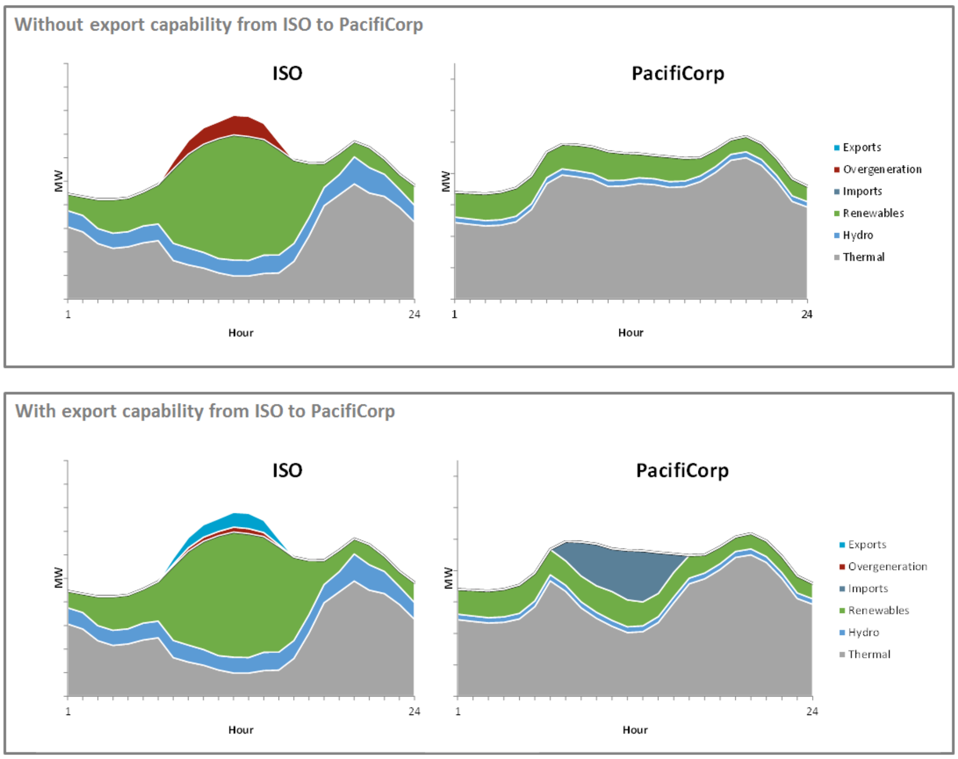
2.2.3 MORE EFFICIENT OVERGENERATION MANAGEMENT

In September 2015, the California legislature passed SB 350, which establishes a 50% RPS standard by 2030. Recent studies have shown that, without changes to existing operating practices and procurement trends, meeting this 50% target would result in significant curtailment of renewable energy. Under a scenario in which solar PV accounts for the majority of California's new renewable resources, for instance, curtailment could occur in more than 20% of hours and comprise nearly 10% of total available renewable generation in 2030.[19] On the margin, curtailment of new solar PV resources could reach as high as 65% of expected output.[20]

PacifiCorp and ISO integration would enable a portion of this renewable overgeneration to be used to serve customers in the PacifiCorp service territories, as Figure 4 illustrates. In the upper portion of the figure ("Without export capability"), California is unable to export solar PV overgeneration to the PacifiCorp region and must curtail it. In the lower portion of the figure ("With export capability"), thermal generators in PacifiCorp are backed down to allow California to export solar PV overgeneration to PacifiCorp.

[19] E3, 2014, *Investigating a Higher Renewables Portfolio Standard in California*, p. 14, https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.
[20] See ibid., p. 15.

Figure 4. Illustrative impact of day-ahead export capability from ISO to PacifiCorp



This greater operational flexibility for addressing overgeneration benefits both ISO and PacifiCorp customers. To meet their RPS requirements, ISO customers must replace curtailed overgeneration by procuring additional renewable energy to meet annual RPS targets. Reducing overgeneration lowers their procurement costs, creating savings that are passed on to customers. By backing down thermal generation, PacifiCorp reduces fuel costs, leading to customer savings, and also reduces CO_2 emissions in its service territories.[21]

[21] By enabling PacifiCorp to reduce thermal dispatch and assuming displacement of natural gas-fired generation, overgeneration management could reduce CO_2 emissions in PacifiCorp's territory by 0.2 million metric tons in

Additionally, some of the renewable procurement cost savings in California are expected to accrue to PacifiCorp customers through market price dynamics.[22]

2.2.4 RENEWABLE PROCUREMENT SAVINGS

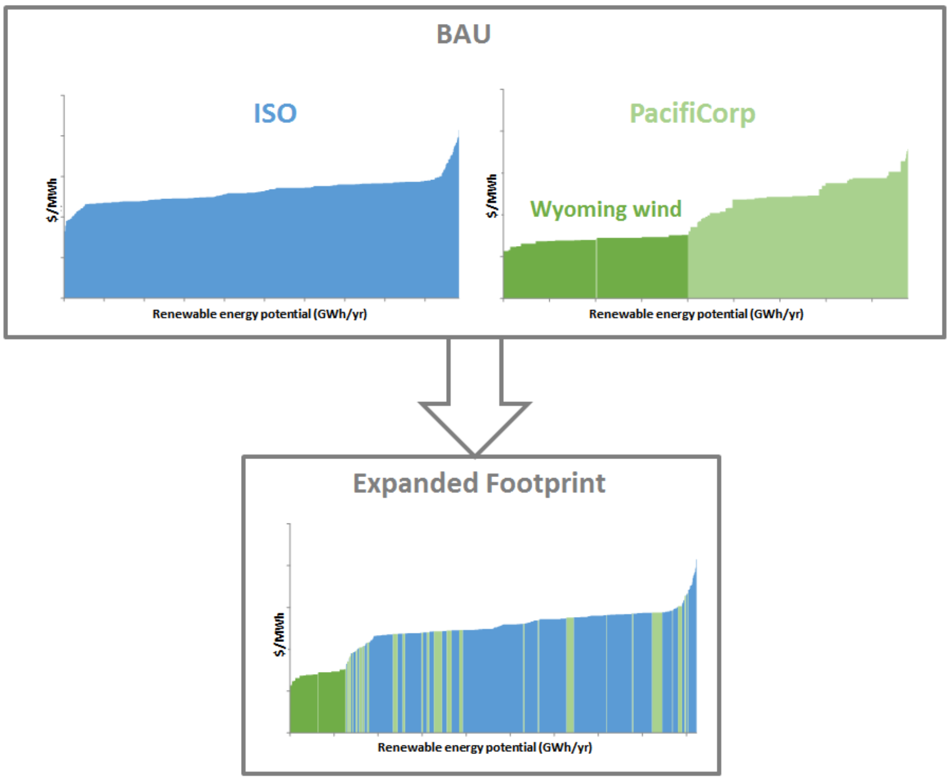
In both PacifiCorp and the ISO, the highest quality undeveloped renewable resources are often located far from load centers, requiring new transmission lines to deliver their energy to customers. These resources can be very low cost, but require larger-scale development to achieve the economies of scale in transmission necessary to lower per-unit ($/MWh) transmission costs. Without economies of scale, high transmission costs can make remote renewable resources uneconomic.

Wind in Wyoming is an important example of a high-quality resource in PacifiCorp's service territory that requires significant new transmission to access cost-effectively. PacifiCorp's near-term demand for new renewable resources may not be sufficient to fully cover the cost of large scale transmission investment. Similarly, ISO customers would benefit from the improved economies of scale for regional transmission needed to access lower cost renewable resources that would reduce the cost of meeting a 50% RPS target. PacifiCorp and ISO integration can facilitate joint transmission planning processes that could enable access to high-quality, low-cost wind resources from Wyoming.

2024 and by 0.6 million metric tons in 2030. Emission reductions will be greater if overgeneration management displaces coal-fired generation.

[22] The technical appendix provides further detail on assumptions for calculating the distribution of benefits for PacifiCorp and ISO customers from more efficient overgeneration management.

Figure 5. Illustrative renewable resource supply curves for the ISO, PacifiCorp, and combined across the PacifiCorp-ISO footprint



Resource cost (in $/MWh), excluding transmission, shown on the y-axis, and cumulative renewable energy (in GWh/yr) shown the x-axis. The dark green portion of PacifiCorp's renewable resource supply curve represents Wyoming wind; the light green portion represents other renewable resources within PacifiCorp's service territory.

Figure 5 illustrates the benefits of developing renewable resources from geographically diverse areas of the West for both ISO customers and PacifiCorp. The figure highlights the low cost position of wind from Wyoming within separate and joint renewable resource supply curves for PacifiCorp and the ISO. Limited to in-state resources, ISO customers will have moved significantly up the ISO renewable supply curve by 2030 to meet a 50% renewable requirement. On this higher part of the supply curve, costs are increasing due to higher marginal overgeneration, lower resource quality, higher cost technologies, and required transmission upgrades. Without regional coordination, and with consideration of evolving state and federal policies, PacifiCorp would also likely procure renewable resources on a more expensive part of its resource supply curve (light green portion of Figure 5), avoiding high per-unit transmission costs to access low cost resources such as Wyoming wind.

By integrating the two supply curves, a significant amount of in-state resource development in California will still be required, but ISO customers can obtain cost savings for their overall portfolio by displacing the need to develop the highest cost in-state resources. Integration can also help reduce the cost of developing renewable resources for PaciCorp customers by enabling greater economies of scale for transmission development.

PacifiCorp's need and timing for additional renewable procurement remains uncertain, depending on the future direction of federal and state policies and uncertainties in future renewable energy costs. To reflect this uncertainty, in the low benefits scenario we assume PacifiCorp has minimal need for new renewable resources, and we exclude potential savings from renewable procurement for both PacifiCorp and the ISO. In the high benefits scenario, we assume federal and state environmental policy developments and increased customer demand accelerate PacifiCorp's need for new renewable resources, and that coordinated planning enables joint development of geographically diverse renewable resources such as Wyoming wind.

Diversification of ISO customers' renewable portfolios through inclusion of out-of-state wind resources, such as Wyoming wind, would also increase the value of California's in-state renewable resources by reducing curtailment risk. Previous analysis has shown that, by itself, portfolio diversification can reduce marginal curtailment faced by new solar PV projects by one-third by 2030.[23]

2.3 Benefits Estimates

For the four quantified benefit categories in Table 4, we estimate low and high scenario cost savings for PacifiCorp and ISO customers for the years 2020 through 2039. We report annual results for 2024 and 2030, and as a present value over the 2020 to 2039 time horizon. The start year for the analysis, 2020, represents a date shortly after PacifiCorp's expected integration with the ISO. The year 2030 represents a longer-term date after which major new investments have been made in the PacifiCorp and ISO systems. The year 2024 represents a nearer-term intermediate year between 2020 and 2030.

This section provides an overview of results. A detailed description of the methods used to calculate these results is available in a separate technical appendix.

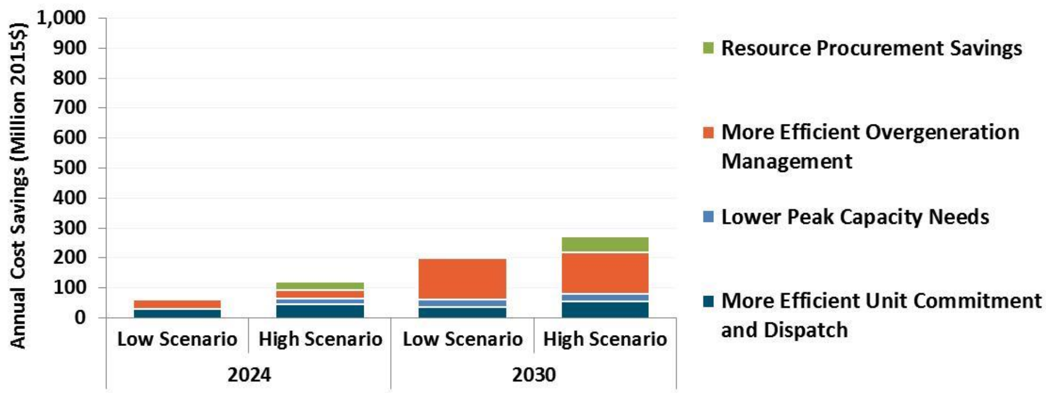
2.3.1 BENEFITS TO PACIFICORP CUSTOMERS

We estimate that annual cost savings for PacifiCorp in 2024, incremental to the EIM, range from $62 million (low scenario) to $122 million (high scenario)

[23] E3, 2014, *Investigating a Higher Renewables Portfolio Standard in California*, https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

(Figure 6). In the low scenario, approximately half of the savings are from more efficient unit commitment and dispatch and the other half are from more efficient overgeneration management. The high scenario includes renewable procurement savings, savings from lower peak capacity needs, and larger savings from more efficient unit commitment and dispatch, consistent with the assumptions described in section 2.2 and in the technical appendix to this report.

Figure 6. Annual incremental cost savings (million 2015$) to PacifiCorp by benefit category, low and high scenarios, 2024 and 2030



By 2030, PacifiCorp's incremental cost savings rise to $200 to $272 million per year. In the low scenario, most of the increase in 2030 savings relative to 2024 is from lower peak capacity needs and significant further reductions of renewable overgeneration. Most of the increase in 2030 savings in the high scenario relative to 2024 is from reductions in renewable overgeneration and higher renewable procurement savings.

Over a 20-year period, from 2020 to 2039, the present value of these four categories of savings for PacifiCorp ranges from $1.6 to $2.3 billion (Table 5).[24] The largest two sources of savings – more efficient overgeneration management and more efficient unit commitment and dispatch – account for a combined 73% to 90% of total present value savings.

Table 5. Present value of incremental cost savings (million 2015$) for PacifiCorp, low and high scenarios, 2020-2039

Benefit Category	Present Value of Cost Savings, 2020-2039 Low	High
More efficient unit commitment and dispatch	$449	$673
Lower peak capacity needs	$161	$240
More efficient overgeneration management	$1,011	$1,011
Renewable procurement savings		$395
Total benefits	**$1,621**	**$2,319**

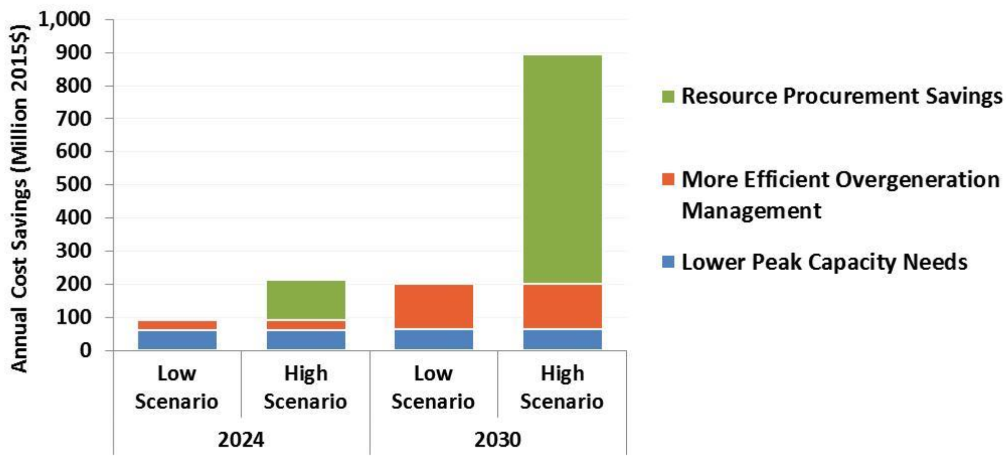
2.3.2 BENEFITS TO ISO MEMBER CUSTOMERS

We estimate that annual cost savings for current ISO customers, incremental to the EIM, range from $92 million to $213 million in 2024 (Figure 7). In the low scenario, two-thirds of savings in 2024 are from lower peak capacity needs, with the remainder from more efficient overgeneration management. The high scenario also includes renewable procurement savings, which account for more than half of total savings. As described in section 2.2, neither scenario includes savings from more efficient unit commitment and dispatch, though ISO member

[24] All discounting uses a 6.66% nominal discount rate and 1.9% inflation rate, consistent with the PacifiCorp 2015 IRP assumptions. For simplicity, we use a single discount rate for all entities. Values here are 2020 present values.

customers are likely to realize at least some cost savings from efficiency improvements.

Figure 7. Annual incremental cost savings (million 2015$) to ISO customers by benefit category, low and high scenarios, 2024 and 2030



Note: The savings shown in the figure for more efficient overgeneration management (orange bars) are isolated to those enabled by CAISO exports to PacifiCorp, regardless of whether wind is procured outside of California. The resource procurement savings in the high scenario (green bars) reflect two incremental impacts of procuring Wyoming wind: (1) a price impact, where the delivered cost of Wyoming wind is less than that of certain California renewable resources; and (2) a quantity impact, where the more diversified regional portfolio further reduces marginal overgeneration and the need to build additional renewables to meet the RPS target.

By 2030, ISO member cost savings rise to $203 to $894 million per year. In the low scenario, most of the increase in savings relative to 2024 is from significant further reductions in renewable overgeneration. Note that even in this low scenario, the broader, more efficient regional system creates a cost savings opportunity for California to meet its 50 percent RPS goals, regardless of its decision on whether or not to procure high quality wind outside of the California.

Most of the increase in savings in the high scenario relative to 2024 is from a significant increase in renewable procurement savings and more efficient overgeneration management. The large increase in renewable procurement savings is primarily from avoiding higher portions of the renewable supply curve within California (see section 2.2) and demonstrates the significant opportunity for California to achieve a portion of its 50% renewable portfolio standard (RPS) target at a substantially reduced cost.

Over a 20-year period, from 2020 to 2039, the present value of these four categories of cost savings for ISO customers ranges from $1.8 to $6.8 billion (Table 6). In the low scenario, savings are split between more efficient overgeneration management (57%) and lower peak capacity needs (43%). In the high scenario, renewable procurement savings account for nearly three-quarters of total cost savings.

Table 6. Present value of cost savings (million 2015$) for ISO customers, incremental to EIM, low and high scenarios, 2020-2039

	Present Value of 20-Year Savings 2020-2039	
Benefit Category	**Low**	**High**
More efficient unit commitment and dispatch	*	*
Lower peak capacity needs	$767	$767
More efficient overgeneration management	$1,011	$1,011
Renewable procurement savings		$4,977
Total benefits	**$1,778**	**$6,755**

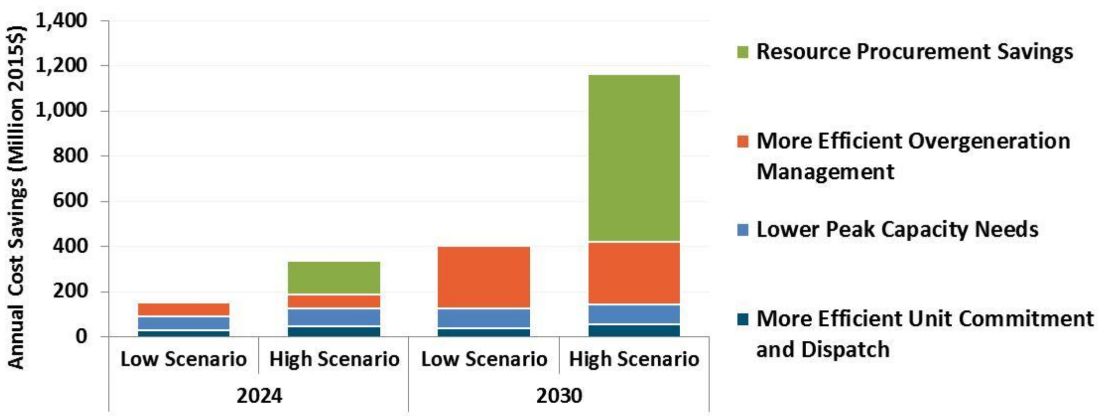
** Expected to be greater than zero but conservatively not included here*

2.3.3 TOTAL BENEFITS

For both entities combined, total annual incremental cost savings range from $153 to $335 million in 2024, and increase to $402 to $1,166 million in 2030

(Figure 8). From 2024 to 2030, most of the increase in savings results from further reductions in renewable overgeneration and, in the high scenario, renewable procurement savings. These results highlight the importance of investment cost savings — on investments for maintaining resource adequacy and particularly on those for meeting renewable energy goals — in assessing the benefits of PacifiCorp and ISO integration.

Figure 8. Total annual incremental cost savings (million 2015$) to PacifiCorp and ISO customers by benefit category, low and high scenarios, 2024 and 2030



Over the 20-year time horizon, the present value of total savings for PacifiCorp and ISO customers, incremental to the EIM, ranges from $3.4 billion to $9.1 billion (Table 7). In the low scenario, more efficient overgeneration management and lower peak capacity needs account for the bulk (87%) of cost savings. In the high scenario, renewable procurement savings account for the majority (59%) of savings, with more efficient overgeneration management contributing another 22%.

Table 7. Present value of total incremental cost savings (million 2015$) for PacifiCorp and ISO customers, low and high scenarios, 2020-2039

Benefit Category	Present Value of 20-Year Savings 2020-2039 Low	High
More efficient unit commitment and dispatch	$449	$673
Lower peak capacity needs	$928	$1,007
More efficient overgeneration management	$2,022	$2,022
Renewable procurement savings		$5,372
Total benefits	**$3,398**	**$9,074**

2.4 Discussion of GHG and Other Environmental Impacts

While a comprehensive quantitative assessment of integration's impact on GHG emissions is beyond the scope of this study, this section describes the operational factors that will influence GHG emissions associated with PacifiCorp and ISO integration. Coordinated transmission planning associated with integration provides opportunities for ISO customers to meet their 50% RPS target by acquiring a portion of their renewable resource demand with a more diversified and lower cost portfolio of renewable resources. Similarly, PacifiCorp customers would be able to take advantage of coordinated transmission planning to lower the incremental cost of new renewable resource additions. Lower renewable resource costs will increase the competitive advantage of renewable resources as compared to other alternatives, particularly when the demand for renewable resources is bolstered by known and prospective state and federal policies. As renewable resources are added to the system, and PacifiCorp absorbs renewable energy from renewable resources added in California through more efficient management of overgeneration, fossil-fired generation will be displaced and this will contribute to GHG emission reductions.

In the shorter term, integration will improve how CO_2 prices for electricity imports into California are incorporated into dispatch decisions, which should provide increasing incentives to displace coal under a coordinated dispatch. On balance, these market changes and expected evolution of the online generation mix should increase the likelihood of net reductions in GHG over the 2015 to 2030 period.[25]

In the longer term, integration is expected to enable continued, low-cost reductions in GHG emissions in California and PacifiCorp's territories, for reasons discussed in this report. In particular, if integration induces other regional participants or enables additional renewable procurement, the lower costs of procurement and reduced overgeneration could provide substantial incentives for incremental GHG reductions over time.

In addition to GHG impact, a recently completed study also assessed land-use and other ecological impacts of different renewable portfolios for California to reach a 50% RPS in 2030.[26] The analysis indicates that a regional approach to renewable procurement for California could bring potential environmental benefits by avoiding development on high impact conservation lands and reduced water use.

[25] For additional discussion of the anticipated impact of integration on GHG emissions, see the technical appendix to this report.

[26] E3 and The Nature Conservancy (2015), *Integrating Land Conservation and Renewable Energy Goals in California: A Study of Costs and Impacts Using the Optimal Renewable Energy Build-Out (ORB) Model*, http://scienceforconservation.org/dl/TNC_ORB_Report_Final_2015.pdf

3 Description of Cost Categories

3.1 Types of Costs

While a comprehensive quantitative assessment of integration costs is beyond the scope of this study, this section describes the type of costs associated with integration. There are two basic categories of integration costs that will need to be estimated: (1) implementation costs and (2) on-going costs. There are two primary types of on-going costs, which include the ISO grid management charge (GMC) and the transmission access charge (TAC).

3.2 Implementation Costs

PacifiCorp's market integration implementation costs will be driven by information technology changes, metering and telecom reprogramming or upgrades, transmission planning activities, settlements reconfiguration, modifications to energy supply management practices and procedures, and project support activities such as legal and project management costs.

The system, interface and application changes implemented for EIM would be fully leveraged as part on an integrated market, which substantially lowers the scope of activities needed for market integration.

Offsetting the cost increases would be savings from the elimination of the California ISO's EIM fee, and from reduced maintenance and licensing fees as EIM information technology modules are substituted for day-ahead modules.

3.3 On-going Costs

3.3.1 GRID MANAGEMENT CHARGE

The GMC is paid by all scheduling coordinators that participate in the ISO. These grid management charges are designed to ensure the ISO recovers its annual operating and financing costs. The charges are levied based on such factors as the quantities of scheduling coordinator meter flows and awards. The greater the economies of scale for an ISO, the lower the GMC collected by the ISO from any individual scheduling coordinator. PacifiCorp would incrementally pay a GMC associated with its day-ahead ISO activities upon becoming a full participating transmission owner. GMC associated with PacifiCorp's real-time market activity would replace the EIM administrative charge, which does not apply to full participants. PacifiCorp's payment of the GMC will reduce the payment obligations of existing and future ISO scheduling coordinators.

3.3.2 TRANSMISSION ACCESS CHARGE

The TAC is the charge assessed for using the ISO-controlled grid. It consists of two components, the regional access charge (RAC) and the local access charge (LAC). The RAC is based on one ISO grid-wide rate. Each participating transmission owner (PTO) determines the LAC. The LAC of non-load-serving PTOs may also be project specific. Each PTO will charge for and collect the LAC, and coordinators pay the wheeling access charge for wheeling. The ISO collects the wheeling revenues from scheduling coordinators on a trading interval basis and repays these to the PTOs based on the ratio of each PTO's transmission revenue requirement to the sum of all PTOs' transmission revenue requirements. The TAC applicable post integration will be determined through a stakeholder process run by the ISO.

4 Conclusions

PacifiCorp and ISO integration would produce a number of benefits for PacifiCorp and ISO customers that are incremental to the EIM. This report provides an estimate of these benefits by quantifying four categories of savings:

+ More efficient unit commitment and dispatch;
+ Lower peak capacity needs;
+ More efficient overgeneration management; and
+ Renewable procurement savings.

We estimate benefits, incremental to EIM, for the first 20 years of PacifiCorp-ISO integration, assumed to be 2020 to 2039, and for two individual years within that time horizon, 2024 and 2030. We address uncertainties by considering low and high scenarios. The high scenario differs in that it assumes: coordinated planning produces renewable procurement savings; earlier thermal capacity needs for PacifiCorp leads to earlier peak capacity savings; and more efficient unit commitment and dispatch creates larger savings for PacifiCorp.

For PacifiCorp, cost savings range from $62 to $122 million (2015$) in 2024, rising to $200 to $272 million in 2030. Over the initial 20-year period, PacifiCorp realizes $1.6 to $2.3 billion in present value savings. For ISO customers, cost savings range from $92 to $213 million in 2024 and rise to $203 to $894 million in 2030. We estimate that 20-year present value savings to ISO customers ranges from \$1.8 to \$6.8 billion. The considerable range in 2030 estimates for ISO customers is driven by assumptions about renewable procurement savings, suggesting the huge potential benefits to California of a regional, collaborative approach to developing and distributing renewable resources.

The results illustrate that the benefits of PacifiCorp and ISO integration will increase with rising penetration of renewable energy. The largest two benefits that we identify in this study — cost savings from more efficient overgeneration management and joint transmission planning for renewable resources — scale upward with renewable procurement needs. The penetration of renewable energy in California is expected to increase beyond 50% after 2030; many other Western states have yet to announce renewable policies beyond 2020 or 2025. Customer demand for renewable energy may encourage additional development. Final definition of federal carbon emission regulations, and potential for future incremental federal policy developments, may also drive the need for further renewable development and other changes in the generation mix. The joint PacifiCorp-ISO system will be able to more flexibly respond to ongoing changes in state and federal policies at a lower cost while maintaining high levels of reliability. Integration will enable PacifiCorp and California utilities to meet renewable energy goals and GHG emissions reduction targets at a lower cost.

Longer-term cost savings from PacifiCorp and ISO integration are linked to planning and investment decisions that require long lead times. For instance, more efficient renewable resource and transmission development depend on planning and approval processes that may require the better part of a decade to complete. Integration of PacifiCorp and the ISO in the nearer term would provide the joint processes and certainty that enable more strategic and efficient longer-term investment decisions. This suggests the need to take a longer-term view of the benefits of integration.

The quantified benefits for both PacifiCorp and ISO customers are sufficient to support continued progress toward PacifiCorp and ISO integration. Ultimately, a successful integration will require PacifiCorp and ISO customers to each have net benefits. The upcoming stakeholder process will provide the necessary guidance to support any changes to the ISO tariff and inform the determination of overall costs and benefits.