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Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

PREPARED FOR

California ISO

PREPARED BY

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This report was prepared for the California Independent System Operator. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, E3, BEAR, Aspen, or their clients.

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Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

Volume 1: Table of Contents

Executive Summary

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate, regional entity ("Regional ISO" or "regional market"). This report, comprising Volumes I through XII, responds to this legislative requirement.

The ISO retained The Brattle Group ("Brattle"), Energy and Environmental Economics, Inc. ("E3"), Aspen Environmental Group ("Aspen"), and Berkeley Economic Advising and Research, LLC ("BEAR") (together with the ISO, the "study team") to evaluate the following impacts of a Regional ISO as outlined by SB 350:

- Overall benefits to California ratepayers;
- Emissions of greenhouse gases and other air pollutants;
- The creation or retention of jobs and other benefits to the California economy;
- Environmental impacts in California and elsewhere;
- Impacts in disadvantaged communities in California; and
- Reliability and integration of renewable energy resources.

In addition, SB 350 requires that the modeling and all assumptions underlying the modeling are made available for public review.[1]

The SB 350 study efforts include a stakeholder process, by which the study team has been providing study assumptions, methodology, results, and detailed descriptions of all of the relevant metrics used in the analyses. The stakeholder process began with the study team presenting the initial framework of the approach and assumptions to be used in the analyses, continued with providing stakeholders interim updates associated with the approach and study assumptions, followed by providing detailed data and explanations of the preliminary results.

[1] California Senate Bill 350, Clean Energy and Pollution Reduction Act of 2015, Article 5.5, Section 359.5.(e)(1).

This stakeholder process involved several days of formal stakeholder workshops, supplemental webinars, data release, a review of study data by stakeholders, and written responses to numerous stakeholder questions.

While this study is conducted in direct response to the California legislative requirement to assess impacts on California and California electricity ratepayers, the study team hopes the information and analyses provided herein and during the stakeholder process can be used by stakeholders in California and in other states to perform their own analyses as they evaluate the potential impacts of regional market participation.

More specifically, the stakeholder process consisted of:

- **February 8, 2016:** stakeholder meeting to discuss proposed study framework, methodology, and assumptions. Stakeholders submitted to the ISO their comments and feedback, which the study team used to refine the study approach, study assumptions, and the scenarios and sensitivities analyzed.
- **March 18, 2016:** the study team responded to stakeholder comments from the February 8 stakeholder meeting.
- **March 30, 2016:** additional detail on study assumptions and methodologies ("early release material") was posted on the CAISO website, in response to stakeholder requests.[2]
- **April 14, 2016:** the study team hosted a webinar to discuss the early release materials with stakeholders.
- **May 24–25, 2016:** stakeholder meeting to present and discuss the preliminary study results; stakeholder comments on preliminary study results were due by June 22, 2016.

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[2] Stakeholder materials are posted on the ISO's website at: https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx.

Certain analytical inputs contain detailed system information considered Critical Energy Infrastructure Information under FERC law and must be accessed through a non-disclosure agreement with the ISO. The instructions and NDA template can be found at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx under SB 350 Study Data. If you have any further questions, please contact regionalintegration@caiso.com.

- **June 3 and 10, 2016:** detailed analytical inputs, assumptions, calculations, and results were released for stakeholder review. Supplemental material, in response to ongoing stakeholder requests, was released on June 14, 17, 21, and 22, 2016 and on July 5, 2016.
- **June 10, 15, 21, 22 and July 1 and 6 2016:** released responses to stakeholder questions on the analytical material released.
- **June 21, 2016:** the study team hosted a webinar to discuss the details of the ratepayer impact analysis, including TEAM calculations.
- **July 7, 2016:** in response to stakeholder comments, the ISO reassessed the classification of data files underlying the Senate Bill 350 preliminary study results. During that assessment, the ISO determined that certain confidential files, including those containing output calculations, could be reclassified as public information and are now available on the ISO website.
- **July 12, 2016:** the study team provided responses to stakeholder comments related to the May 24–25 stakeholder meeting.

SB 350 requires the California Public Utilities Commission, the California Energy Commission, and the California State Air Resource Board to jointly hold at least one public workshop where the ISO presents the proposed governance modifications and the results of the study ("Joint Agency Workshop"). The workshop is scheduled to be held on July 26, 2016 at the Secretary of State, Auditorium at 1500 11th Street, First Floor, Sacramento, CA 95814 (enter at 11th and O Streets).

The primary purpose of this report is to inform California policymakers and the California legislature on the impacts to California of transforming the existing CAISO into a regional organization that manages wholesale electricity markets and operations across a broader western region. To undertake this analysis, the study team needed to make several foundational assumptions:

- <u>The study team is not analyzing impacts associated with the ISO's Energy Imbalance Market ("EIM")</u>.[3] This study assumes the EIM may expand to the regional market

[3] The Energy Imbalance Market is a real-time market and it does not incorporate day-ahead unit commitment, day-ahead market dispatch, intra-day adjustments, or coordinated transmission planning and generator interconnections.

footprint with or without implementation of the ISO-operated regional market. The benefits estimated in this study are incremental to those achievable by a regional EIM.[4]

- A number of *plausible* future renewables portfolios can help to meet California's 50% Renewable Portfolio Standard ("RPS") by 2030 ("50% RPS portfolios"). The 50% RPS portfolios used in the study illustrate how regional market impacts may influence renewable generation development and vary across different renewable generation portfolios. We analyze portfolios with California-focused procurement (2030 Current Practice 1 scenario and 2030 Regional 2 scenario), a portfolio with more regionally-focused procurement (2030 Regional 3 scenario), and a number of sensitivities. Each of the sensitivity analyses of California renewables buildout results in a (at least slightly) different 50% RPS portfolio. This study is focused on plausible portfolios for achieving the 50% target under alternative assumptions for the ***sole*** purpose of assessing the benefits of a regional market over a range of plausible renewable procurement scenarios. *This study does not endorse or provide any recommendations about the procurement approach or the future composition of California's 50% RPS portfolios.*

- The study uses a number of assumptions that reflect California policies associated with reducing greenhouse gas ("GHG") emissions from California's electric sector. The policies that are assumed to be in place and are reflected in the analytical assumptions include the deployment of new energy efficiency, new (dispatchable) renewables, energy storage, growth of electric vehicles, time-of-use rates, improved ancillary services, and some fossil-fired generator retirements that reflect expected future policy decisions. In addition, GHG emission allowance prices in California are assumed for each future scenario analyzed. These assumptions do not take the place of policymakers' decisions. Instead, we expect that the California policymaking agencies and load-serving entities will make a determination of how to meet the 50% RPS, how to expand energy efficiency measures for the future, and how to reduce future GHG emissions as required by Assembly Bill 32.

- Assumptions reflect a *range* of the scope and conditions of a regional market. We analyze bookends for the scope of a regional market: at one end, we analyze a regional market that consists only of CAISO and PacifiCorp in 2020; and at the other end, we analyze an

[4] Given that an expanded ISO-operated regional market also enhances real-time operations beyond those that could be achieved through a regional EIM, our estimates will represent a conservative estimate of actual benefits because these additional real-time impacts are not quantified in our study.

expanded Regional ISO that includes most of the U.S. portion of the Western Electricity Coordinating Council ("WECC").[5] The rest of the assumptions about market conditions reflect both near-term year conditions (2020) with electric supply, demand, and fuel prices similar to today's, and longer-term conditions (2030) with significant changes in electric supply, including more renewable generation and significantly less coal-fired generating capacity in the entire Western Interconnection.

- This study's baseline scenarios do not include simulated GHG policies outside of California, other than states' existing RPS in the rest of WECC region. A sensitivity analysis considers the impact of a modest price on GHG emissions on electricity sector emissions in the rest of the U.S. WECC as a proxy for compliance with future environmental regulations, such as the U.S. Environmental Protection Agency's Clean Power Plan.

Our five baseline study scenarios consist of the following two 2020 scenarios and three 2030 scenarios:

- **2020 Current Practice:** reflects near-term market conditions. California has developed the necessary resources to meet its 33% RPS. CAISO operates as-is, with no regional expansion.
- **2020 CAISO+PAC:** reflects near-term market conditions. California has developed enough renewables to meet its 33% RPS. CAISO and PacifiCorp form a Regional ISO. Up to 776 MW of energy transfers from CAISO to PacifiCorp and 982 MW of transfers from PacifiCorp to CAISO (the amount of existing transmission capability between the two areas) are free of economic and operational hurdles. CAISO and PacifiCorp resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements in advance of real-time operations. For any imports into the CAISO region, all of PacifiCorp's generators, including coal plants, are assumed to face the same emissions cost as a generic natural gas combined-cycle generator (a simplification because the simulations cannot identify unit-specific imports and assign unit-specific allowance costs for imports into California). This scenario is compared to the 2020 Current Practice scenario to evaluate the impacts of a very limited initial market expansion.

[5] The WECC region is also referred to as the "Western Interconnection."

- **2030 Current Practice ("Current Practice 1"):**[6] reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with a current practice (in-state) procurement focus. CAISO operates only its current footprint, without regional expansion. Bilateral markets and trading frictions continue and limit the sales and net exports of excess generation from the RPS portfolios of CAISO entities to 2,000 MW. This means it is assumed that bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus export/sell an additional 2,000 MW of (mostly intermittent) renewable resources.
- **2030 Expanded Regional ISO 2 ("Regional 2"):** reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with a ***continued (but not exclusive) in-state renewables procurement focus***. All of the U.S. WECC except for the federal Power Marketing Agencies ("PMAs") (BPA and WAPA) ("WECC without PMAs") is part of an expanded Regional ISO.[7] All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from California's renewables portfolio is more readily absorbed by the regional marketplace, as reflected in a more relaxed physical CAISO export limit (8,000 MW) in contrast to the more constrained bilateral limit in Current Practice 1 (2,000 MW). This scenario is compared to the 2030 Current Practice 1 scenario to evaluate the impacts of the broader regional market. The regional market is assumed to have facilitated the development of additional low-cost renewable generation resources beyond the western states' RPS mandates.
- **2030 Expanded Regional ISO 3 ("Regional 3"):** reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with a ***more region-***

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6 This "Current Practice 1" scenario was previously referred to as "Case 1A".

7 Specifically, the PMAs excluded for the purpose of this analysis are Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. WAPA's Sierra Nevada Region is included in the Balancing Area of North California and, because it is not a separate balancing area, was included in the analysis. The PMAs were excluded solely for providing a smaller than WECC-wide geographic footprint. This choice does not reflect any suggestion that the PMAs would not be interested in participating in a regional market. In fact, in the eastern interconnection, WAPA's Upper Great Plains Region has already joined the Southwest Power Pool.

wide procurement focus than in Regional 2. All of the U.S. WECC without PMAs participates in a Regional ISO. All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from California's renewables portfolio is more readily absorbed by the regional marketplace, as reflected in a more relaxed physical CAISO export limit (8,000 MW) compared to the less flexible (2,000 MW) bilateral limit in Current Practice 1. This scenario is compared to the 2030 Current Practice 1 scenario to evaluate the impacts of the broader (but still not WECC-wide) regional market with more WECC-wide procurement to meet California's RPS. The regional market is assumed to have facilitated the development of additional low-cost renewable generation resources beyond the western states' RPS mandate.

Numerous sensitivity analyses were also studied as summarized in Volume III. The sensitivity analyses were used to test the impact of a variety of factors and alternative assumptions on the study results. The sensitivities address high bilateral trading flexibility, the market's geographic scope, renewable generation costs, alternative RPS and energy efficiency targets, and the extent to which a regional market would facilitate additional renewable generation development in the rest of the U.S. WECC region. We have not analyzed sensitivities focused on alternative assumptions for fuel prices, conventional plant retirements and additions, different weather and load conditions, or different hydro conditions.

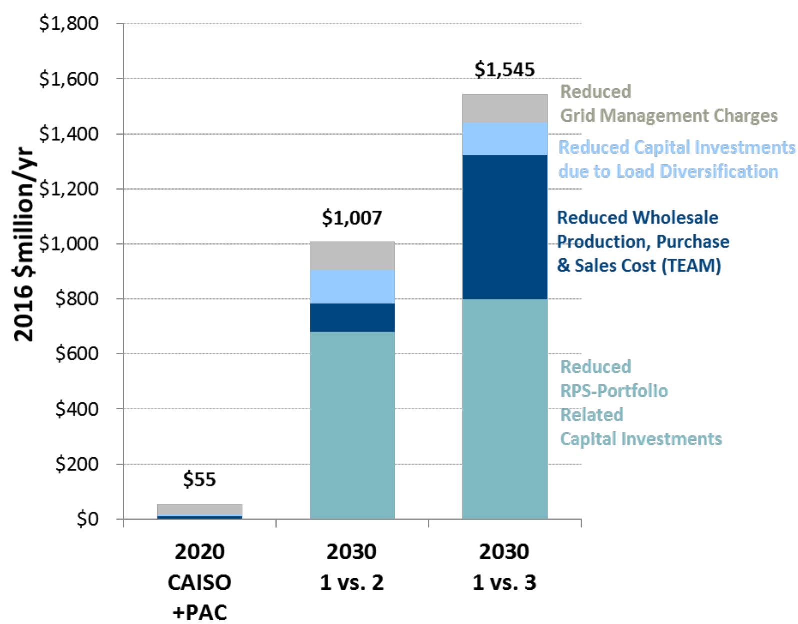
The key findings of the SB 350 analysis with respect to California ratepayer impact, greenhouse gas and other emissions, economic and environmental impacts, and impacts on disadvantaged communities are as follows:

Overall Benefits to California Ratepayers: We estimate an annual net benefit to California ratepayers of $55 million a year in 2020 (assuming the regional market would only include CAISO and PacifiCorp). That benefit grows to a baseline net benefit range of $1 billion to $1.5 billion a year by 2030 (assuming a large regional footprint that includes all of U.S. WECC without PMAs).[8] The 2030 results, which would continue and likely grow in subsequent years,

[8] When including the results of various sensitivity analyses (including higher bilateral flexibility and no additional renewable development), annual 2030 California ratepayer savings range from $767 million/year to $1.75 billion/year.

reflect ratepayer savings in a renewables scenario that achieves California's 50% RPS and meets all existing RPS standards in the rest of the West. Figure ES-1 below summarizes these results and shows that these net benefits to California's ratepayer are composed of: (1) savings from reduced capital investments for RPS-related procurement; (2) reduced production, purchase, and sales costs for wholesale electricity; (3) reduced capital investments from regional load diversification; and (4) reduced grid management charges for system and market operations.[9] The reductions in RPS-related procurement costs stems from reduced renewable generation capacity needs due to reduced curtailments and the ability to develop lower cost renewable resources. Savings associated with wholesale productions, purchase and sales costs are driven primarily by lower-cost imports (during periods when California is importing power) and higher export sales revenues during oversupply conditions (when California would otherwise have to curtail renewable generation or export power at a zero market price). The increased diversity of peak loads in a larger market region reduces generation-related capital investments and the larger geographic footprint reduces the average charge needed to recover the grid management costs of the ISO operating the regional market.

Figure ES-1: Estimated Annual California Ratepayer Net Benefits



* The grid management charge is the ISO's charge for recovering its annual operating costs.
Note that the "Current Practice 1" scenario has previously been referred to as "Case 1A"

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9 A separate sensitivity analysis shows that 2020 California ratepayer benefits would be $258 million/year in a market covering the larger regional footprint.

The ratepayer benefits are annual net benefits, estimated for the years 2020 and 2030. If the regional market grows as assumed in this study, the $55 million/year savings in 2020 is expected to grow to $1.5 billion/year in 2030. Since these ratepayer benefits are associated with true cost reductions, they are expected to be sustained over the long-term, beyond 2030.

Emissions of Greenhouse Gases and Other Air Pollutants: The market simulations undertaken for this effort show that California's energy policy initiatives will substantially reduce the emissions of GHGs associated with serving California electricity loads. Our analysis of GHGs focuses on carbon dioxide, which accounts for 99 percent of all GHG emissions from electric sector operations. Our estimate of electric-sector CO_2 emissions[10,11] includes emissions from all simulated generation sources on the high-voltage grid, including biomass, geothermal, and other sources that may not necessarily be included in the California Air Resources Board's GHG accounting under AB 32. Figure ES-2 shows that the estimated CO_2 emissions associated with serving California retail electricity loads (including CO_2 emissions from imported power) will be approximately 63.6 million metric tons by 2020 (well below recent historical levels of about 90 million metric tons per year in 2010–2013 and 107.5 million metric tons in 1990). These emissions are projected to decrease further to 49.2 million metric tons by 2030, even under the Current Practice 1 scenario, without implementing a regional market.[12] Furthering California's GHG emissions reduction goals by implementing a regional market is estimated to decrease 2030 CO_2 emissions associated with serving California loads from 49.2 million to 44.6–45.5 million metric tons. These projected 2030 CO_2 emissions levels are about 58% below California's 1990 electric-sector CO_2 emissions. They are also well below the CO_2 emissions limits set by the U.S. Environmental Protection Agency's Clean Power Plan ("CPP") for California's power sector. We have interpreted SB 350 as requiring a study of GHG and other air pollutant emissions from the power sector. This study does not make any assumptions or analyze emissions from other categories of sources in California, and it does not analyze the potential reactions from other sectors of the economy when emissions from the power sector change.

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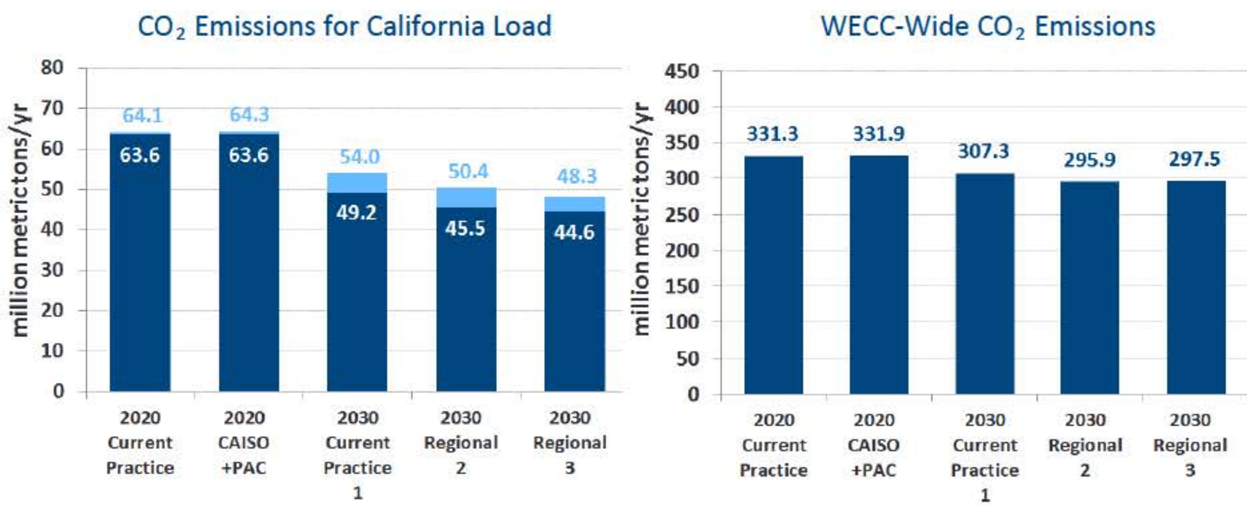
10 Note that the emissions results presented in this final report differ slightly from preliminary results presented on May 24, 2016; all cases were updated to: (1) include CO_2 emissions during plant starts and (2) exclude wheeling-through transactions in California emissions accounting.

11 Our estimates of future CO_2 emissions are for all modeled electric generating sources on the high-voltage grid, including biomass and geothermal.

12 The term "tonne" is meant to mean "metric ton" and two terms are used interchangeably.

The SB 350 analysis includes a simulation of the power sector across the entire WECC, including the western Canada (British Columbia and Alberta) and northern Mexico portions of WECC. On a WECC-wide basis, and despite continued projected load growth in the rest of WECC, the CO_2 emissions are estimated to decrease from 331.3 million metric tons in 2020 to 307.3 million metric tons in 2030, even without a regional market. On top of this reduction, the regional market is estimated to further reduce 2030 emissions, to below 300 million metric tons. These reductions are estimated to materialize prior to implementing any additional measures that the western states would use to comply with the CO_2 emissions limits set under the CPP. Aside from the emissions reductions facilitated by a regional market, the main drivers of the estimated CO_2 emissions reductions include: the announced retirements of coal-fired generators throughout WECC through 2030; the relative economics of different fuels and generating technologies; the design and implementation of specific environmental regulations in California and the rest of WECC; and the magnitude of renewable energy resource development throughout the West. The simulation assumptions associated with these factors made for the purpose of this study are explained in more detail in Volume V.

Figure ES-2: Annual Electricity-Sector CO_2 Emissions in California and WECC-Wide



Notes:

[1] On the left chart, the higher value reflects the CARB's GHG accounting for GHG imports. The lower value includes an adjustment to "credit" California for GHG exports, which is not currently part of the CARB's accounting.

[2] The emissions results presented in this final report differ slightly from preliminary results presented on May 24, 2016, reflecting updates to: (a) include CO_2 emissions during plant starts and (b) exclude wheeling-through transactions in California emissions accounting.

In addition, in a sensitivity analysis conducted to simulate a future under which states in the rest of the U.S. WECC would implement policies to further reduce GHG emissions akin to those mandated under the CPP, we assess the potential impact of implementing a regional market assuming a $15/metric ton carbon price is imposed on electric sector emissions across the western states outside of California. That sensitivity analysis does not include any assumptions about how each state might implement their emission reduction plans to comply with specific environmental regulations, such as the CPP.[13]

The expanded regional market will also decrease electric-sector emissions of nitrogen oxides (in part by reducing the need for extensive cycling of California natural gas plants), sulfur dioxide, and particulate matter emissions within California and WECC-wide.[14]

The Creation or Retention of Jobs and Other Benefits to the California Economy: The impacts of a Regional ISO-operated market are expected to create numerous and diverse jobs and economic benefits to California households and enterprises. We estimate that a regional market, growing from a CAISO plus PacifiCorp footprint in 2020 to the larger regional market by 2030, will create 9,900–19,300 additional jobs in California, compared to Current Practice, primarily due to reduced cost of electricity. We estimate that, by 2030, the regional market will increase statewide household real income, across all income brackets. We estimate statewide household real disposable income to increase by between 0.1% and 0.2%, an increase in community incomes equal to $290–550 per household annually by 2030. Moreover, the study results show that a regional market would lead to higher California Gross State Product, real economic output, real wages, and state revenue. A regional market with more California-focused renewables procurement to meet the state's RPS (instead of more out-of-state procurement) can yield even greater economic benefits to the state, but there are potential tradeoffs among ratepayer benefits, local employment, economic impact benefits, and environmental impacts as discussed next.

Environmental Impacts in California and Elsewhere: Our analysis for 2030 shows that implementing a regional market increases the efficiency of investments in low-cost renewable energy generation, including investments in new wind and solar resources to meet California's RPS. With a more efficient renewable resource expansion to meet the state's RPS, implementing a regional market also reduces impacts on land use, biological resources, and water use. The land-use impact associated with building new wind and solar developments in California is

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13 For the purpose of providing context to our results we do, however, compare our CO_2 emissions results to hypothetical mass-based state CO_2 standard under the Clean Power Plan as discussed below.

14 Our analyses are subject to important limitations for the purpose of analyzing specific air quality impacts as discussed further in footnote 23 of Volume I of this report.

reduced by 42,600 acres in Regional 2 and by 73,100 acres in Regional 3. The land use for deploying new wind and solar outside of California to meet the state's 50% RPS is reduced by about 31,900 acres relative to the Regional 3 scenario, if California continues to focus on in-state development for RPS as is assumed in the Regional 2 scenario.[15] The environmental study inherently reflects tradeoffs between in-state versus out-of-state development. With more of an out-of-state renewables-procurement focus to meet California's RPS, land use and impacts on biological resources are shifted from California to out-of-state. New transmission builds to support renewable resource development outside of California are likely to further increase out-of-state land use. Due to a regional market's more efficient dispatch of generating units across the West, water use for thermal generators is reduced, specifically for natural gas-fired combined-cycle units in California, and for natural gas-fired and coal-fired units in the rest of WECC.

Impacts on Disadvantaged Communities: Our analysis shows that the regional market would confer economic benefits on disadvantaged communities. We estimate that implementing a regional market with CAISO plus PacifiCorp in 2020, and expanding to a larger Regional ISO by 2030, would stimulate real income and jobs growth in most of California's disadvantaged communities, particularly in the Inland Valley, Greater Los Angeles, and Central Valley Competitive Renewable Energy Zones ("CREZs"). Real disadvantaged community incomes would increase by an amount corresponding to $170 to $340 of existing real annual household incomes, and total full-time employment would rise by 1,300 to 4,600 jobs between 2020 and 2030. A regional market mitigates construction-related adverse environmental impacts by reducing renewable resource development needs to meet California's RPS, particularly in the Westlands area where solar resource development is reduced due to more efficient renewable integration of a regional market (see the next finding and Volumes IV and XI). Reduced generation from natural gas-fired generators in California decreases the amount of water used during power production and provides benefits to disadvantaged communities by decreasing power plant emissions in the San Joaquin Valley and South Coast air basins.

[15] The higher land-use impact of the Regional 3 scenario (compared to Regional 2) relates to the scenario's higher share of wind resources and the fact that wind generation requires more land per MWh of renewable energy than solar generation. Note, however, usually less than 10% of the acreage within a typical wind site may be disturbed, while the remainder of the land remains undisturbed and available for other uses (e.g., for range land and farming).

Reliability and Integration of Renewable Energy Resources: A regional market reduces the cost of maintaining reliability by reducing the need for load-following resources, operating reserves, and planning reserves. A regional market improves integration of renewables to achieve California's 50% RPS by reducing curtailments of renewable resources in a regional market (relative to current practices based on bilateral trading) and therefore would allow California to build less renewable generating capacity (megawatts) to meet the same goals. Regional pooling of resources to meet flexibility reserves allows the region to balance the intermittent output of wind and solar generation much more efficiently than operating individual balancing areas independently. These aspects of reliability benefits are quantified in the load diversity analysis (meeting the same resource adequacy level with less generating capacity) and nodal energy market simulations (more optimized power flows, reduced curtailments, reduced need for load-following and operating reserves) of our study. In addition, a regional market increases operational reliability through a variety of factors, such as better real-time visibility of system conditions in the larger regional footprint and improved management of unscheduled regional power flows. Improved management of the existing grid and better regional transmission planning will additionally reduce the transmission-related renewables integration and generator interconnection costs. The liquidity and transparency of a regional market will attract renewable generation investments beyond those needed to meet the RPS requirements of western states. This means the quantified benefits are a conservatively low estimate in that they do not include the monetary value of a variety of benefits related to system operations, planning, enhancing reliability, and more efficiently integrating or interconnecting renewable energy resources in the rest of the region. These additional operational reliability benefits are described and documented in detail in Volume IX of this study.

A Regional ISO: Why Now? The analyses show that regional market benefits (1) significantly depend on the size of the regional market; and (2) increase quickly with California renewable generation mandate. Experience with the Energy Imbalance Market and other regional markets show that it takes several years to set up a regional market. Additionally, it takes new participants several years to obtain the regulatory approvals and undertake the necessary preparations before they are able to achieve market participation. As a result, it will take a number of years to achieve a regional market of sufficient size to provide the available regional market benefits. Thus, the sooner a regional market of sufficient size can be developed, the sooner California customers will be able to benefit from the investment and operating cost savings a regional market can provide—particularly as RPS mandates increase over time.

Volume I. Purpose, Approach, and Findings of the SB 350 Regional Market Study

A. Purpose of the SB 350 Study

The purpose of this study is to respond to and comply with the requirements set out in California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015 ("SB 350"). As part of SB 350, the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") is required to conduct one or more studies that would analyze the potential impacts of transforming the Existing ISO into a multistate, regional organization ("Regional ISO" or "regional market") by revising the Existing ISO's governance structure.

To comply with the legislative requirements, the ISO has retained The Brattle Group ("Brattle"), Energy and Environmental Economics, Inc. ("E3"), Aspen Environmental Group ("Aspen"), and Berkeley Economic Advising and Research, LLC ("BEAR") (together with the ISO, the "study team") to evaluate the following impacts of a Regional ISO as outlined by SB 350:

- Overall benefits to California ratepayers;
- Emissions of greenhouse gases and other air pollutants;
- The creation or retention of jobs and other benefits to the California economy;
- Environmental impacts in California and elsewhere;
- Impacts in disadvantaged communities in California; and
- Reliability and integration of renewable energy resources.

In addition, SB 350 requires that the modeling and all assumptions underlying the modeling are made available for public review.[16]

As part of the study effort, the CAISO developed a schedule that provided stakeholders opportunities to review and provide input on the: (a) study scope; (b) proposed methodologies; (c) schedule of the study; and (d) draft results and findings. The details of the stakeholder

[16] California Senate Bill 350, Clean Energy and Pollution Reduction Act of 2015, Article 5.5, Section 359.5.(e)(1).

engagement process are described in more detail in Volume II. Key modifications made to the study scope and assumptions based on this stakeholder feedback include the following:

- Refined renewable portfolio optimization and cost assumptions for the various renewable generation technologies, including storage;
- Revised the hypothetical regional footprint for 2020 to include only CAISO and PacifiCorp, instead of a larger footprint previously proposed;
- Revised the hypothetical regional footprint for 2030 to include the U.S. portion of the Western Electricity Coordinating Council ("WECC") region minus the Federal Power Marketing Agencies ("PMAs")—BPA and WAPA—instead of the previously-proposed entire U.S. WECC;
- Ensured that all analyses focused on California are performed for the entire state, not just the current CAISO footprint;
- Conducted various sensitivities as suggested by various stakeholders;
- Ensured compliance with current Renewable Portfolio Standards ("RPS") in the rest of U.S. WECC (including Oregon's new 50% RPS by 2040);
- Incorporated additional announced coal-fired power plant retirements and renewable and conventional plant additions from various utilities' integrated resource plans;
- Simulated California and the rest of U.S. WECC in a sensitivity that represents some form of regional compliance with the EPA's Clean Power Plan standard; and
- Updated load growth, energy efficiency, various demand-side resource inputs, time-of-use rates, and electric vehicle charging assumptions to be consistent with the California Energy Commission's 2015 Integrated Energy Policy Report results.

While this study is conducted in direct response to the California legislative requirement to assess impact on California and California electricity ratepayers, the study team hopes that the information and analyses provided will be useful for stakeholders in California and in other states in conducting their own future analyses of regional market benefits.

B. SB 350 Study Approach

The study has been conducted jointly by the California ISO and four consulting firms. The Brattle Group was engaged to lead the effort and to conduct the production cost simulations, a portion of the ratepayer impact analysis, the load diversity analysis, the renewable integration analysis and, in coordination with the CAISO team, the assessment of reliability impacts. In addition, The Brattle Group reviewed a large number of other market studies to provide a reference point for the results of this study and inform a discussion of potential benefits not quantified. The renewable procurement portfolio and a portion of the ratepayer analysis were conducted by E3, the environmental study was conducted by Aspen, and the employment and economic impact analyses were conducted by BEAR. Jointly, Aspen and BEAR also analyzed the likely environmental and economic impacts on disadvantaged communities in California. For the purpose of this report, the contributing staff of the California ISO and the four consulting firm is referred to as the "study team." The study team developed the study approach and assumptions, presented the results, released the input data and study results to stakeholders, and coauthored this report.

1. Scope of the Regional Market

The study approach starts with the geographic scope of the regional market analyzed. We considered a broad range of potential footprints of a Regional ISO. In response to stakeholder feedback, study scenarios were developed to analyze bookends for the geographic scope of a regional market: for 2020, we analyze only CAISO and PacifiCorp (which had approached the CAISO about becoming a market participant, which would expand the current ISO footprint) as participants in the regional market; for 2030, we analyze an expanded Regional ISO that, but for the federal Power Marketing Agencies, includes the rest of the U.S. portion of WECC.[17] Similarly, the assumptions on market conditions reflect both a near-term year (2020) with electric supply, demand, and fuel prices similar to today's, and a longer-term year (2030) with significant changes in electric supply, including more installed renewable generation and less coal-fired generating capacity. The study's assumed geographic regional footprint and range of

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[17] Specifically, we excluded the following federal power marketing agencies from the Regional ISO footprint: Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. The Sierra Nevada Region is included in the Balancing Area of North California and because it is not a separate balancing area, was included in the analysis. The power marketing agencies were excluded from the regional market footprint in response to stakeholder comments that including the entire U.S. WECC system in the regional footprint was overly optimistic and would consequently overstate the benefits of a regional market. The power marketing agencies were chosen for exclusion simply by virtue of their unique operational and regulatory situation and not because of any indication that they would not be interested in joining a regional market.

market conditions are documented in more detail in Volume III. For both study years, the regional market cases are compared to a Current Practice case that reflects CAISO operations and bilateral markets in the rest of WECC as-is, without an expanded Regional ISO market.

Our analysis does not make any presumptions about whether or when any of the other Balancing Authorities in the WECC might join the real-time Energy Imbalance Market ("EIM"). Instead, by focusing only on day-ahead market simulations (without consideration of any forecasting and real-time market uncertainties), our analyses exclude any impacts related to the EIM. This means the benefits analyzed and quantified in our study do not include any that could be (or would be) achieved by expanding the EIM to the geographic market footprint analyzed for 2030. Given that an expanded ISO-operated regional market enhances real-time operations beyond those that could be achieved through a regional EIM, our estimates represent a conservative estimate of actual benefits because these additional real-time impacts are not quantified in our study.

2. Baseline Scenarios

We defined five base scenarios, combining the assumed scope of a regional market and procurement alternatives for achieving California's 50% Renewable Portfolio Standard ("50% RPS"):

- 2020 Current Practice: reflects near-term market conditions. California has developed enough renewables to meet its 33% RPS. CAISO operates as-is, with no regionalization.
- 2020 CAISO+PAC: California has developed enough renewables to meet its 33% RPS. CAISO and PacifiCorp form a Regional ISO. Up to 776 MW of energy transfers from CAISO to PacifiCorp and 982 MW of transfers from PacifiCorp to CAISO are free of economic and operational hurdles. CAISO and PacifiCorp resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. For any imports into the CAISO region, all of PacifiCorp's generators, including coal plants, are assumed to face the same emissions cost as a generic natural gas combined-cycle generator (a necessary simplification because the simulations cannot identify unit-specific imports and assign unit-specific allowance costs for imports into California). This scenario is compared to the 2020 Current Practice scenario to evaluate the impacts of this very limited market expansion.

- **2030 Current Practice (Current Practice 1)**: This scenario (previously referred to "Case 1A" in the preliminary material shared with stakeholders) reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with a business-as-usual, in-state procurement focus. CAISO operates only its current footprint (no regional market). Bilateral markets and trading frictions continue and limit the sales and exports of excess generation from the RPS portfolios of CAISO entities to 2,000 MW. This means it is assumed in this Current Practice 1 scenario that bilateral markets would accommodate the re-export/sale of all prevailing existing imports (ranging from 3,000-4,000 MW per hour) plus achieve the export/sale of an additional 2,000 MW of (mostly intermittent) renewable resources.
- **2030 Expanded Regional ISO (Regional 2):** reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, *with a continued (but not exclusive) in-state renewables procurement focus*. All of the U.S. WECC except for the federal Power Marketing Agencies (BPA and WAPA) ("WECC without PMAs") is part of a Regional ISO.[18] All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from California's renewables portfolio is more readily absorbed by the regional marketplace (reflected in a more relaxed 8,000 MW physical CAISO export limit). This scenario is compared to the 2030 Current Practice (Scenario 1) to evaluate the impacts of the broader (but still not WECC-wide) regional market with a continued in-state focus to meet California's RPS.
- **2030 Expanded Regional ISO (Regional 3):** reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with *more of an out-of-state procurement focus than in Regional 2*. All of the U.S. WECC without PMAs participates in a Regional ISO. All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from California's renewables portfolio is more readily

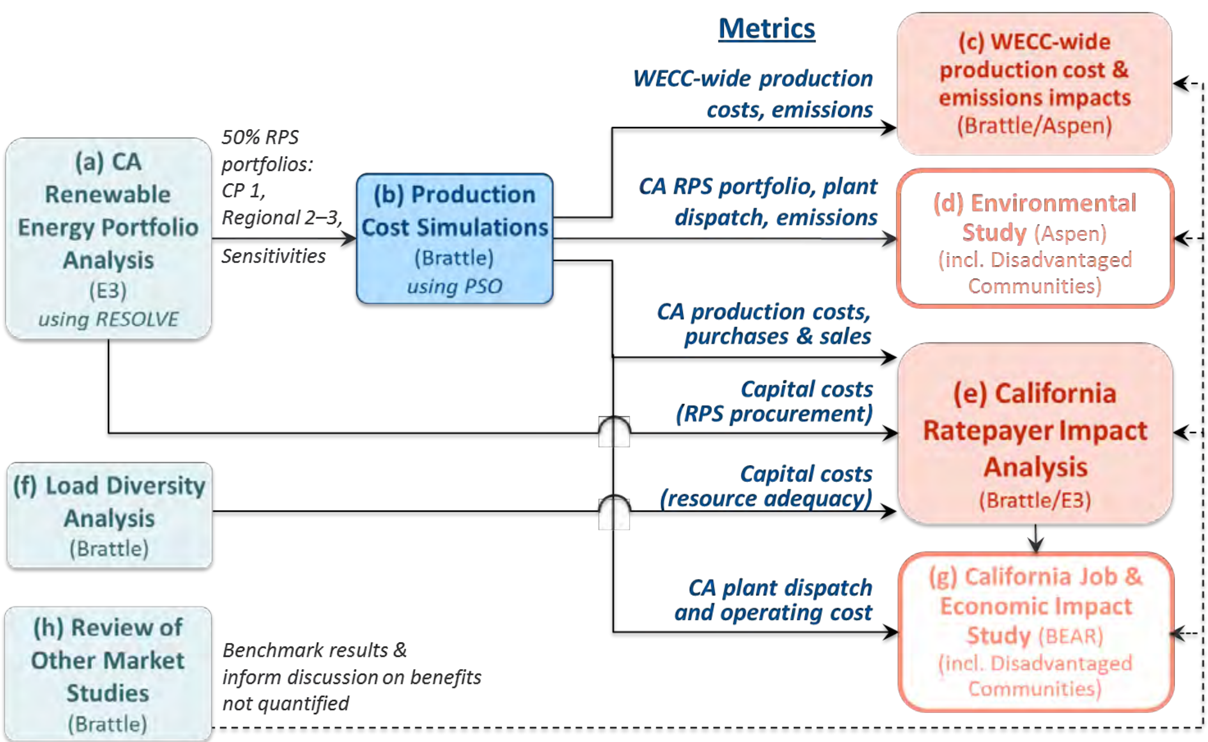
[18] Specifically, the PMAs being excluded for the analysis are Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. WAPA's Sierra Nevada Region is included in the Balancing Area of North California and, because it is not a separate balancing area, was included in the analysis.

absorbed by the regional marketplace (reflected in a more relaxed 8,000 MW physical CAISO export limit). This scenario is compared to the 2030 Current Practice 1 scenario to evaluate the impacts of the broader (but still not WECC-wide) regional market with more WECC-wide procurement to meet California's 50% RPS.

More detailed descriptions of the future scenarios are presented in Volume III. Renewable portfolios assumed to be used to meet California's Renewable Portfolio Standard is explained further in Volume IV.

The study process and analytical approach to meet the requirements of SB 350 is illustrated in Figure 1.

Figure 1: Summary of the Study Process



3. Renewable Energy Portfolio Analysis

Our study approach begins with an analysis of possible portfolios of incremental renewable resources necessary to meet California's 50% RPS by 2030 (depicted by box (a) of Figure 1). These 50% RPS portfolios differ by scenario as they reflect economically-efficient portfolios based on assumptions about the regional market operations and available resources. The resulting portfolios are used in the other portions of this study to analyze how the regional market might affect the California. For the projection of plausible renewable generation portfolios, we use a renewables capacity expansion model—the Renewable Energy Solutions ("RESOLVE") model developed by E3—to identify an optimal renewable resource portfolio to meet California's 50% RPS for each scenario. We analyze current-practices portfolios with California-focused procurement (Current Practice 1 and Regional 2), a portfolio with more regionally-focused procurement (Regional 3), and a number of sensitivities, each of which results in a different RPS portfolio.

This study is focused on plausible portfolios for achieving the 50% RPS under alternative assumptions; this study is not endorsing or providing any recommendations for the procurement of any specific 50% RPS portfolio. The detailed RESOLVE analysis of California renewable portfolios is presented in Volume IV of this report.

4. Production Cost Analysis

After the assumptions of the renewable portfolios were developed for each of the scenarios analyzed we conducted detailed production cost simulations of the entire western power grid, consisting of California and the rest of the WECC ("rest of WECC")[19] (depicted by box (b) of Figure 1). The production cost simulation tool—Power Systems Optimizer ("PSO"), developed by Polaris Systems Optimization Inc.—is a nodal, security-constrained least-cost unit commitment and dispatch model, comparable to the production cost models utilities and RTOs regularly use for regional transmission and generation resource planning.[20] The production cost simulations were conducted on a deterministic basis (consistent with simulating day-ahead market conditions, without capturing the uncertainties between the day-ahead and real-time market and therefore not capturing incremental benefits provided by a full regional real-time energy imbalance market) for the study years 2020 and 2030 and for the five baseline scenarios described above.

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[19] The term "WECC" is often generalized throughout the electric industry to refer to the entire western electric grid's physical system (also referred to as the "Western Interconnection"), stakeholders, and/or markets. When discussing Balancing Authorities, WECC's system studies, and WECC's production cost models we use the term's specific meaning. Otherwise, we use the term's more general meaning.

[20] Other frequently-used nodal production cost simulation models include software tools such GridView, Promod, GE-MAPS, Plexos, and Dayzer.

The production cost simulations estimate hourly fuel use, production cost,[21] generation, and CO_2 emissions from each generating resource in California and the rest of WECC, which includes the western Canadian (British Columbia and Alberta) and northern Mexican portions of the WECC. To estimate impacts of regional market operations on WECC-wide production costs[22] and on CO_2 emissions in California and in the rest of WECC, we compared the results for the Current Practice scenarios to the results of regional market scenarios (depicted by box (c) of Figure 1). Using results for unit-specific generation dispatch and generic emissions rates by technology, the study team then estimated impacts on criteria pollutants and particulate matter in California and the rest of WECC.

5. Environmental Study

The 50% RPS portfolios and the production cost results are used as an input for the environmental study (depicted by box (d) of Figure 1).[23] The power generated at each of the

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21 Production costs include total system-wide operating costs associated with fuel burn, variable O&M, and emissions allowances.

22 Although this metric is not a requirement of SB 350, it provides important context for the other impacts we measure.

23 The production cost model does track unit-specific NOx and SO_2 emissions. However, as with most production cost models there are some limitations to interpreting absolute levels of unit-specific air emissions, since the model does not mimic the precise accounting of emissions rates or control equipment use found in actual historical data. This is because, absent a material emissions allowance cost, such as for NOx, SO_2, and PM2.5, emissions rates do not affect the models' unit commitment or dispatch results. Also, production cost models typically do not have the capability to decide when to turn emissions control equipment on or off. In addition, our analyses have important limitations for the purpose of analyzing specific air quality impacts. The production cost analysis conducted for the SB 350 study was employed at a regional scale, with assumptions about how power may be traded between California and the rest of the WECC under different market configurations. The production cost analysis provides a potential dispatch profile for the generators in the region with a given set of assumptions about the power plants. The SB 350 study involves an analysis of GHG and other air pollutant emissions changes of the power sector. The study does not make any assumptions or analyze emissions from other categories of sources in California, and it does not analyze the potential reactions from other sectors of the economy when emissions from the power sector change. The SB 350 study does not include an ambient air quality impact analysis of ambient ozone or PM2.5 levels or other air pollutant concentrations. For the purposes of the Disadvantaged Communities analysis, the regional modeling output for generators in specific communities was examined only at the air basin level. The regional modeling utilizes general characteristics of each generator type in the state, not actual generator specific data, which most of the time are proprietary to the owners of the generators. Thus, there are limits to how well a regional model can discern specific activities at specific generators when general characteristics about the generators are used in the simulations. For the Disadvantaged

Continued on next page

different types of power plants is used as a basis for estimating air emissions and water-use impacts. The 50% RPS renewable resource portfolios are used as a basis for estimating land-use and biological impacts. The environmental study uses a variety of California and national databases to analyze specific renewable development areas as well as areas that are biologically or environmentally sensitive. The environmental study approach, assumptions, and detailed results are presented in Volume IX.

6. California Ratepayer Impact Analysis

Our California ratepayer impact analysis (depicted by box (e) of Figure 1) is composed of several analytical components: (1) savings associated with more efficient renewables procurement to meet the state's 50% RPS; (2) savings associated with a reduced cost of generating or procuring electric energy to meet California loads; (3) load diversity benefits that reduce the generating capacity needed to meet the state's resource adequacy requirements; and (4) savings associated with reduced Grid Management Charges ("GMC") that need to be recovered from California loads to cover the cost of expanded Regional ISO market operations.

- **Renewable procurement cost** savings are value obtained through increased ability to: (a) to procure lower-cost resources and (b) build less resources to meet the same RPS requirement due to a reduction in the curtailment of renewable resources. The details of these investment-related cost savings and the associated analyses are presented in Volume IV.
- **Cost reductions from power production, purchases, and sales** are based on the production cost simulation results, utilizing the CAISO's Transmission Economic Assessment Methodology ("TEAM") to estimate the impact on California ratepayers. The TEAM has been developed by the CAISO to evaluate the potential impact of transmission projects on California ratepayers. The analysis takes into account California's use of utility-owned and utility-contracted generation resources to serve California electricity customers, while also considering the estimated costs and revenues of the California utilities'

Continued from previous page

Communities analysis, the results do not use any generator specific permit limits, as those are specific to each source in each air district. Emissions are summed up by air basins. The Disadvantaged Communities analysis results are based on these basin-wide totals, not emissions from generating plants in or near the Disadvantaged Communities. Emissions given in this part of the report are for the annual periods of the two study years and do not show the effect of summer NOx emissions on ozone levels in Disadvantaged Communities.

purchases and sales in the wholesale power market. The results reflect the estimated total cost of wholesale electricity supplies that California ratepayers would pay for. The details of the TEAM analysis of California production, purchase, and sales costs are provided in Volume V.

- Load diversity cost savings (depicted by box (f) of Figure 1) are generation procurement cost savings associated with reducing the amount of generating capacity needed to meet peak load and planning reserve margin requirements in a larger, more diversified regional market. These procurement cost savings result from a reduction in capacity required to serve the reduced joint coincident peak of the regional market area. The details of the load diversity analysis and the associated annualized generation investment cost savings are included in Volume VI.
- Reduction in ISO operating costs paid by California customers: This portion of the California ratepayer analysis includes the savings to California customers associated with the reduction in the portion of the total ISO operating costs that need to be recovered from California customers through the ISO's Grid Management Charge. While the total cost of ISO operations is expected to increase with an expanded regional market, the higher costs can be spread across a much larger regional footprint, which reduces the charges per MWh of load served in the region. The GMC-related assumptions and calculations are presented in Section F of Volume VII.

7. California Job and Economic Impact Analysis

The 50% RPS portfolios, production cost results, and California ratepayer impacts are used as key inputs to the California job and economic impact study (depicted by box (g) of Figure 3). Within this analysis, we evaluate the potential employment and overall economic impact on California associated with differences in renewables procurement and ratepayer costs across the scenarios analyzed. BEAR used its own statewide economic model to measure how a regional power market will impact California jobs and the California economy. The model is customized to reflect California's economy, and it includes detailed modules for high-level macroeconomic trends, the transportation sector, the technology sector, and the electric sector. The model has a detailed occupational component that tracks up to 95 occupations across 200 economic sectors. The metrics of statewide economic indicators include Gross State Product, real economic output, real state-wide income, state tax revenues, net number of jobs created, and household real incomes. The detailed job and economic impact analysis is presented in Volume VIII.

8. Impact on Disadvantaged Communities

Both the environmental study and the California job and economic impact study estimate the impacts on California's disadvantaged communities.[24] The environmental study identifies air basins that coincide with high concentrations of disadvantaged communities and evaluates the likely changes in air emissions in those areas. The study identifies key renewable development areas (Competitive Renewable Energy Zones) that coincide with high concentrations of disadvantaged communities and evaluates environmental impacts of the 50% RPS portfolios in those areas. For the job and economic impact study, the study disaggregates results to the census-tract level to estimate the impacts specific to disadvantaged communities. For the employment and economic impacts on disadvantaged communities, we focus on the net number of jobs created and changes in the average household's real income in disadvantaged communities. The detailed analyses of impacts on disadvantaged communities are presented in Volume X.

9. Renewable Integration and Reliability Impacts

The larger, more diversified regional market footprint reduces the cost of integrating renewable generation resources, including the cost of balancing the intermittent output of these resources. This, in turn, facilitates the development of renewable resources in the regional market area. Implementing a Regional ISO-operated market, including a centralized day-ahead unit commitment process, also increases the reliability of the western power system. Key aspects of these renewable integration and reliability benefits are quantified in: (1) the load diversity analysis, which assesses—based on subregional resource adequacy requirements estimated by WECC with industry-standard loss of load probability analyses—how resource adequacy requirements can be met with less generating capacity in a regional market (Volume VI of this report); (2) the nodal market simulations, which simulate more optimized power flows on the transmission grid, reduced curtailments, and reduced need for ramping, load-following, and operating reserves at high levels of renewable resource development (Volume V); and (3) the renewable investment optimization, which recognizes integration benefits when selecting the renewable portfolios that can meet California's 50% RPS (Volume IV). Additional operational

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[24] Disadvantaged communities are defined by the California Environmental Protection Agency, based on a ranking of several indicators on pollution burden and population characteristics by census tract. All census tracts (and population within) ranked within the top 25 percentile are considered disadvantaged within a statewide context.

and other aspects of renewable integration and reliability impacts of an expanded ISO-operated regional market are discussed in Volume XI.

10. Review of Other Regional Market Studies

The study team reviewed a wide range of relevant existing studies of regional market impacts similar or related to the scope of the SB 350 study requirements to ensure consistency in methodology; to compare and contrast findings; and to leverage analyses of potential impacts that are not specifically analyzed and quantified in this SB 350 study (depicted by box (h) of Figure 1). The types of studies that the study team reviewed include: (a) studies analyzing the integration of renewable resources in the western U.S.; (b) other U.S. regional market impact studies; and (c) European experiences with regional market and renewable integration. A summary of this review of other regional market studies in presented in Volume XII.

C. Key Analytical Assumptions and Sensitivities

We developed and applied a number of key assumptions that include data and input from stakeholders in both California and the rest of the WECC. Based on SB 350 study stakeholder comments and feedback, we updated projections of California electricity market fundamentals and other modeling refinements that are necessary to answer questions posed in the SB 350 legislative requirements. Additional analytical assumptions have been included in our analyses to create detailed representations of the California economy (for the job and economic impact analyses) and the WECC-wide electricity system (for the renewable portfolio and production cost simulations). The details about our modeling assumptions can be found in the other volumes of this study. For the purpose of this study, the most relevant assumptions include:

- The assumed scope of regionalization, as discussed above;
- Wholesale electricity market fundamentals, including future supply characteristics, demand, and fuel prices;
- The degree to which current practices inhibit trading and more efficient use of system resources within the WECC area, such as assumed hurdle rates among balancing areas and the assumed limit on bilateral exports from California;
- The degree to which a larger regional market enables more efficient new investments, such as new renewable resource development needed to meet California's 50% RPS, new

regional transmission to access low-cost renewable generation areas, and renewable generation investments beyond RPS mandates; and

- Cost of GHG emissions, for within California and in the rest of WECC, including the assumed administrative treatment of the imports into California from the rest of WECC and the associated GHG emissions, including how those emissions are accounted for under California's cap-and-trade system.

In addition to the baseline scenarios discussed above, various sensitivities are used to test how some study assumptions about future policies and electricity market fundamentals affect our findings. Specifically, the sensitivity analyses focus on the California renewable generation procurement costs, overall ratepayer impact, and the changes in emissions, since those results rely most heavily on the study assumptions. The key categories of sensitivity analyses include:

- **Renewable portfolio sensitivities**: An important question this study addresses is whether, and by how much, an expanded regional market can benefit California ratepayers by enabling more efficient and less costly renewable generation development to meet the California's future RPS mandates. A Regional ISO-operated market can provide two benefits to California. First, an expanded market reduces renewable integration costs and helps to offload the renewables that are surplus to California's needs in any particular time period. Second, reducing the operational and economic barriers among WECC's balancing areas can reduce curtailments of in-state renewable generation and improve access to low-cost renewable resource areas and technologies in the rest of the WECC. The impacts of renewable portfolio options on California ratepayers will be sensitive to assumptions about the costs and geographic availability of various renewable resources and technologies. The baseline regional market scenarios analyze the impacts of a mostly in-state procurement focus (Regional 2) and a more out-of-state procurement focus (Regional 3). In addition, the study team analyzed a number of sensitivities around the composition of the renewable energy portfolios that could affect the estimated California impacts. The renewable resource portfolio sensitivity analyses included evaluations of the impacts of higher coordination and flexibility in the current bilateral markets, a doubling of energy efficiency measures envisioned by SB 350, variations on the cost and availability of renewable technologies, and further increases in the achieved future RPS to 55%. The assumptions and results associated with these renewable procurement sensitivities are discussed in more detail in Volume IV.

- **Production cost sensitivities**: An important component of the overall impacts to California ratepayers is the cost of producing or procuring electricity and delivering that electricity to serve electricity customers ("production cost"). Production costs mostly consists of fuel, variable O&M, generating plant start-up costs, and emissions allowance costs. The separate operations of individual balancing areas (of which there currently are 38 in the entire WECC) can create material operational inefficiencies and hurdles to trading that limit how efficiently low-cost resources can be dispatched to serve the collective needs of the larger WECC-wide power system. For example, under the current bilateral market framework, it would be more difficult for California entities to schedule and export power during oversupply conditions created by a high-renewable-generation future. Bilateral trading inefficiencies can also prevent the higher utilization of lower-cost resources to provide energy, system flexibility (load-following), operating reserves, and other system services. By reducing such inefficiencies and trading barriers, an expanded regional market can yield significant production cost savings to California and across the WECC. These production cost impacts will be sensitive to both the magnitude of system flexibility under current-practice system operations and the geographic size of the regional market.

  To assess the sensitivities around these assumptions, the study team analyzed five sets of production-cost sensitivity analyses: (1) one that evaluates the potential impacts of lower barriers in the bilateral trading market (*i.e.*, "2030 Current Practice 1B," representing higher bilateral flexibility); (2) one that isolates the impact of regional market operations while keeping the renewable portfolios the same in both the current practice and regional market simulations (*i.e.*, without changing the renewable portfolio assumptions); (3) one that hypothetically assumes a larger regional market footprint even under near-term market conditions (*i.e.* 2020 with an expanded WECC without PMA regional market footprint); (4) one without the additional renewable resource developments beyond RPS that are assumed to be facilitated by a regional market; and (5) one that simulate GHG regulations in the rest of WECC region as a proxy for CPP compliance. The assumptions and results associated with these production cost sensitivities are presented in more detail in Volume V.

- **Air emissions sensitivities**: One of the requirements under SB 350 is to analyze the potential regional market impact on air emissions, particularly on GHG emissions, in California and elsewhere. The study team interpreted the requirement to include an analysis of how an expanded ISO-operated regional market could affect the air emissions from the electricity sector in California and the rest of WECC. Subject to carbon-related penalties imposed on generators in California and elsewhere, and the extent of renewable development across the region, a regional market will increase the efficient usage of lower-cost generation. In this context, the study team analyzed two sensitivities to better understand the extent to which regional market operations may affect GHG emissions in California and across the WECC. One sensitivity assumes a $15/tonne CO_2 emissions allowance cost across the WECC outside of California; another sensitivity assumes that higher renewables development beyond RPS does not materialize in the regional market. The assumptions and results associated with these sensitivities are discussed in more detail in Volumes V and IX.

These sensitivity analyses were developed in direct response to stakeholder feedback, capturing a wide range of stakeholder suggestions. Stakeholders suggested that additional scenarios and sensitivities be conducted, including (but not limited to): (a) alternative regional footprints to consider, (b) alternative assumptions on renewables technology development costs and availabilities, (c) alternative assumptions on electricity market fundamentals (*e.g.*, load, electric vehicle adoption, energy efficiency), and (d) the amount of renewable resources that would be developed beyond the collective RPS requirements across WECC. Many of these additional sensitivities are analyzed and presented in Volumes IV and V from a renewable procurement portfolio and production cost perspective. A summary and description of all scenarios and sensitivities analyzed is presented in Volume III.

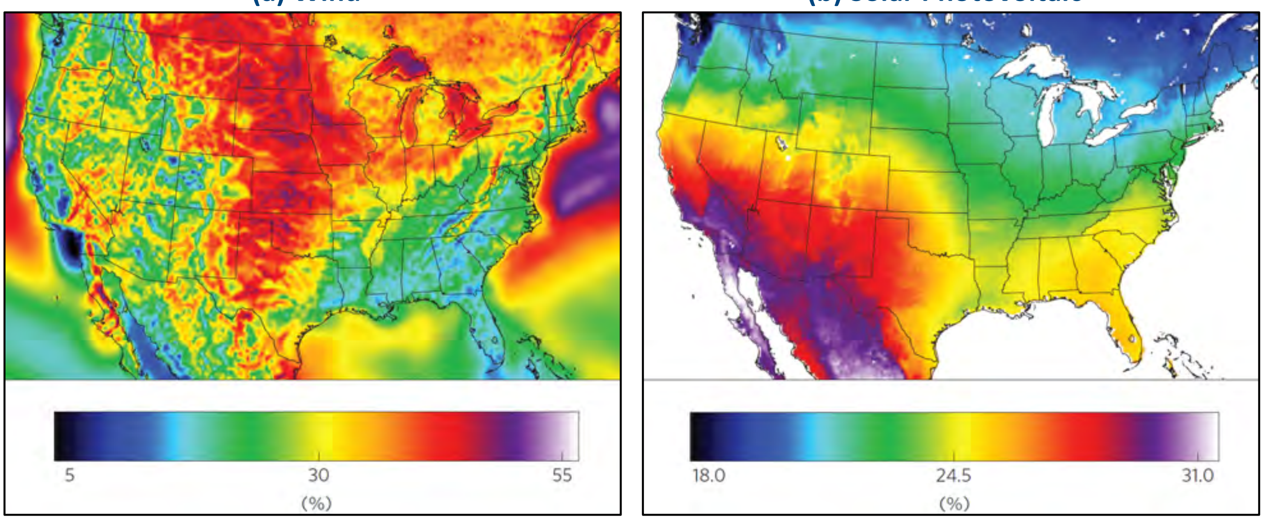
D. PORTFOLIOS TO MEET CALIFORNIA'S 50% RENEWABLE PORTFOLIO STANDARD

The study team began the SB 350 study by developing plausible future renewable resource portfolios that would cost-effectively satisfy California's 50% RPS in 2030. To examine the potential impact of expanded regional market operations across different renewable portfolios, E3 used the RESOLVE production simulation and capacity expansion model. The model solves for least-cost renewable portfolios based on different assumptions about operational friction and the cost and magnitude of available renewable resources that California could procure from different areas within the WECC region. The results of this analysis provide a set of resource portfolios that are carried forward throughout the rest of the study.[25]

The magnitude of renewable resources that are available to be procured from different areas within the WECC region will affect the cost of renewable procurement because of the significant geographic variation in the quality of renewable resources. Figure 2 illustrates the extent to which wind and solar resource potential varies across the U.S., with high-quality wind resource potential across the Great Plains that stretches into Wyoming and New Mexico, and high-quality solar resource potential across the entire Southwest.

Figure 2: U.S. Wind and Solar Generation Capacity Factors[26]

(a) Wind **(b) Solar Photovoltaic**



Higher-quality wind and solar resources yield high capacity factor generating resources, which result in lower average costs, in terms of $/MWh of renewable energy. Subject to available transmission capabilities (or new transmission investments), the areas with the highest-capacity factor renewable resources are the most cost-effective locations for renewable energy resource

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25 The resulting renewable portfolios are not meant to determine how the California utilities should procure renewable resources to meet the state mandate. Those decisions will be made by the appropriate authorities.

26 Source: MacDonald, Alexander E, Christopher T.M. Clack, *et al.*, "Future cost-competitive electricity systems and their impact on US CO2 emissions," *Nature Climate Change* (January 25, 2016): DOI: 10.1038/NCLIMATE2921. Reproduced with permission from Earth System Research Laboratory, NOAA.

development for meeting the region's RPS requirements and for meeting demand for renewable generation from customers that goes beyond RPS mandates.

As discussed above, E3 used its RESOLVE model to select the least-cost portfolios of renewable resources and integration solutions for meeting California's 50% RPS in 2030 for each of the various baseline scenarios and sensitivities. The model selects an optimal portfolio of solar, wind, geothermal, biomass, and small hydroelectric generating resources based on assumed technology costs and system constraints.[27] In all scenarios and sensitivities, the model assumes cost-effective renewable integration solutions are available, including: time-of-use retail rates, growth in electric vehicles with workplace charging, new pumped storage and geothermal capacity, and new energy storage resources. Resources are added to ensure 50% of the energy for load is met by renewable resources despite curtailed output in the energy market. Renewable energy resources are curtailed if the output cannot be consumed in California or be exported to neighboring systems during periods of oversupply with insufficient flexibility in the bilateral or regional markets to absorb the power.[28] Additional renewable resources are added to the portfolio if necessary to replace the curtailed output. This means that renewable curtailments are valued at their replacement cost and thus the total cost of the portfolio increases with the level and frequency of curtailments.

All scenarios start with the same portfolio of renewable resources (assumed under contract) to meet a 33% RPS by 2020, based on the California Public Utility Commission's ("CPUC's") RPS Calculator (version 6.1; "RPS Calculator"). The 33% RPS portfolio assumes compliance with the CPUC's Storage Decision and significant growth in behind-the-meter solar photovoltaic ("PV") generation as projected by the CEC in its 2015 Integrated Energy Policy Report ("IEPR").[29]

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27 Geothermal, hydroelectric, and biomass were not originally chosen for the least-cost portfolio. However, in the interest of providing a more diverse portfolio for the analysis we included an additional 500 MW of geothermal and 500 MW of pump storage in all portfolios. Additional other fuel-types could meet these requirements in the ultimate 2030 portfolios.

28 The simulated renewable contracts assume the seller of the renewable generation is fully compensated for any curtailed output.

29 California Public Utilities Commission, Decision Adopting Energy Storage Procurement Framework and Design Program, Decision 13-10-040, Rulemaking 10-12-007, decision issued October 21, 2013.

California Energy Commission, 2015 Integrated Energy Policy Report, CEC-100-2015-001-CMF, June 29, 2016.

For 2030, the analysis assumed that all California load-serving entities procure enough incremental renewable generation to meet the state's 50% RPS. To do so, the study team employed various assumptions about future resource availability, as summarized below. The total in-state renewable potential, shown in Figure 3, is based on the RPS Calculator, with some modifications to reflect tailored study areas defined by the environmental study team (discussed in Section F.4 below). In the Current Practice 1 and Regional 2 scenarios (both focused on in-state procurement), the out-of-state renewable generation potential for meeting California's RPS mandate is constrained to include only the out-of-state resources potential that is estimated to be deliverable on the existing grid without requiring major new transmission investments. Resources that would require major new interregional transmission projects are excluded. In the Regional 3 scenario (with a more regional procurement focus), the portfolio considers both renewable resources that can be delivered through existing transmission as well as those that would require major new transmission investment. Figure 4 shows the assumed out-of-state resource potential in each of these scenarios.

Figure 3: California Renewable Potential Considered in RESOLVE
Incremental to 33% Portfolio in CAISO

Resource	Zone	Potential (MW)
Geothermal	Greater Imperial	1,384
	Northern California	424
	Subtotal	***1,808***
Solar PV	Central Valley & Los Banos	1,000
	Greater Carrizo	570
	Greater Imperial	1,317
	Kramer & Inyokern	375
	Mountain Pass & El Dorado	-
	Northern California	1,702
	Riverside East & Palm Springs	2,459
	Solano	551
	Southern California Desert	-
	Tehachapi	2,500
	Westlands	1,450
	Subtotal	**11,924**
Wind	Central Valley & Los Banos	150
	Greater Carrizo	500
	Greater Imperial	400
	Riverside East & Palm Springs	500
	Solano	600
	Tehachapi	850
	Subtotal	***3,000***
Total California Renewable Potential		**16,732**

Figure 4: Out-of-State Resource Potential Included in RESOLVE
Incremental to 33% Portfolio in CAISO

Resource		Description	Potential (MW)		
			Current Practice 1	Regional 2	Regional 3
Arizona Solar PV		High quality solar PV resource, available for delivery on existing transmission system	1,500	1,500	1,500
New Mexico Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	1,000	1,000	1,000
Oregon Wind		Low quality wind resource, available for delivery on existing transmission system	2,000	2,000	2,000
Wyoming Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	500	500	500
Total Out-of-State Resources Available			**5,000**	**5,000**	**11,000**

The assumptions on cost and performance for renewable technologies, transmission for renewables, and storage, were all modified based on stakeholder feedback. These assumptions are documented in detail in Volume IV.

RESOLVE is an investment and operational model designed to inform long-term planning questions around renewables integration in California and other systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon with one-hour dispatch resolution for a study area, in this case the CAISO footprint. The model incorporates a geographically simplified representation of the neighboring regions in the West to characterize and constrain flows into and out of the ISO footprint. RESOLVE identifies the optimal investments in renewable resources, various energy storage technologies, new natural gas plants and natural gas plant retrofits (if any were needed), subject to an annual constraint on delivered renewable energy that reflects the RPS policy, a resource adequacy constraint to maintain reliability, constraints on operations that are based on a linearized version of zonal unit commitment and feedback from the ISO, and scenario-specific constraints on the ability to develop specific renewable resources in various areas. Informed by the RESOLVE results for the CAISO area, E3 also selected a renewable portfolio for the rest of the state independently to meet the 50% RPS mandate because the RESOLVE model only contained information for load serving entities inside the CAISO and additional resource procurement assumptions for the rest of California needed to be developed outside of the RESOLVE model.

The Resulting 50% RPS Portfolios. Figure 5 shows the resulting 50% RPS portfolios for California for the three 2030 baseline scenarios. These portfolios are incremental to what has been contracted to meet the state's 33% RPS by 2020. These 2030 portfolios are used as key inputs to the remainder of this SB 350 study:

- Current Practice 1 (current practice, no regional market): Relative to the 33% RPS starting point, California would need to procure 16,652 MW of renewable generation, with about 2/3 in-state and 1/3 out-of-state using existing transmission. About half is from utility-scale solar (8,601 MW) and half from wind (7,551 MW), with a small amount of geothermal (500 MW). All resources are procured as a whole (*i.e.*, energy, capacity, and renewable energy credits), with the exception of 1,000 MW of northwest wind and 1,000 of southwest solar, which are assumed to be procured by California only for their renewable energy credits.
- Regional 2 versus Current Practice 1: In this regional market case with a continued focus on in-state renewables, California procures slightly more in-state solar (+203 MW), significantly less in-state wind (–1,100 MW), less out-of-state wind from the Northwest (–885 MW), and more southwest solar (+500 MW). Overall, California procures fewer MW of renewable generation capacity (–1,282 MW) to produce the same GWh of renewable energy production as a result of reduced renewable generation curtailments due to the expanded export constraints offered through regional market operations in the Regional 2 scenario.
- Regional 3 versus Current Practice 1: In this regional market case with a shift toward relying on lower-cost renewable resources in the larger western region, California procures significantly less in-state solar (–4,161 MW) and in-state wind (–1,100 MW), more out-of-state wind (+1,644 MW), and more southwest solar (+500 MW). Overall, California needs to procure much less renewable energy resource capacity (–3,118 MW) to meet the same GWh renewable energy production needs, due to reduced curtailment and more of out-of-state procurement of high-capacity-factor wind in resources in Wyoming and New Mexico in the Regional 3 scenario.

The 50% RPS portfolios developed for the three baseline scenarios of this study are simply three of many possible portfolios that may be used to satisfy California's 50% renewable energy goals.

Figure 5: Portfolios to Meet California's 50% Renewables Portfolio Standard Incremental to 33% Portfolio

Megawatts by 2030

	Current Practice 1	Regional 2	Regional 3
CAISO simultaneous export limit	2,000	8,000	8,000
Procurement	Current practice	Current practice	WECC-wide
Operations	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)			
California Solar	7,601	7,804	3,440
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,447	562	318
Northwest Wind RECs	1,000	1,000	0
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	0	0	1,995
Southwest Solar, Existing Transmission	0	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	1,962
Total CA Resources	11,101	10,204	5,840
Total Out-of-State Resources	5,551	5,166	7,694
Total Renewable Resources	**16,652**	**15,370**	**13,534**
Energy Storage	972	500	500

Gigawatt-Hours in 2030

	Current Practice 1	Regional 2	Regional 3
CAISO simultaneous export limit	2,000	8,000	8,000
Procurement	Current practice	Current practice	WECC-wide
Operations	CAISO	WECC-wide	WECC-wide
Portfolio Composition (GWh)			
California Solar	21,482	22,147	9,827
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,574	891
Northwest Wind RECs	2,803	2,803	0
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	0	0	8,037
Southwest Solar, Existing Transmission	0	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	0	0	7,905
Total CA Resources	33,904	31,685	19,365
Total Out-of-State Resources	16,654	15,661	27,601
Total Renewable Resources	**50,558**	**47,346**	**46,966**

The selected portfolios are used for the purpose of this study to illustrate how the regional market impacts vary across different renewable development and regional market assumptions.

This study is not meant to provide any recommendations or advice about the actual composition of California's future renewable procurement activities.

In addition to the baseline scenarios, the optimal procurement of renewable generation portfolios were evaluated for the following sensitivities: high coordination under bilateral markets, high energy efficiency, high flexible loads, low portfolio diversity, high rooftop photovoltaic solar, high out-of-state availability, high RPS (55%), and lower solar cost.

E. Production Cost Simulations

The study's production cost simulations provide estimates of how the western wholesale electric system might respond to a regional ISO-operated market. Incorporating the 50% RPS portfolios and a number of other assumptions, the production cost simulations estimate generator-specific electricity production, fuel use, CO_2 emissions, and production costs (cost of fuel, emissions, and variable O&M) for the entire WECC region subject to available transmission capabilities, transmission charges, and transactions costs related to bilateral trading. These results are inputs to the ratepayer impact analysis, the economic and jobs analysis, and the air emissions analysis.

We simulated five baseline scenarios and six sensitivities using Power Systems Optimizer, a software tool developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost, security-constrained unit commitment and economic dispatch with a full nodal representation of the entire regional transmission system, similar to the unit commitment and dispatch performed during actual ISO operations.

1. General Simulation Assumptions

As a starting point to the simulations, we relied on the data contained in CAISO's own "Gridview" production cost model used for its 2015/16 Transmission Planning Process ("TPP"). This ISO transmission planning model is based on the 2024 model developed by WECC's Transmission Expansion Planning Policy Committee ("TEPPC") but contains a number of refinements to the CAISO portion of the grid. Based on this model as the starting point, we updated key assumptions on California loads, distributed solar, natural gas prices, California GHG prices based on CEC's 2015 IEPR data, and the transmission grid topology for 2020 and 2030. We also updated transmission charges ("wheeling rates") between WECC Balancing Authorities, the representation of planned WECC transmission projects, the modeling of pumped storage hydroelectric generators, and the unit-commitment and startup specifications for natural gas-fired generators. A more detailed description of PSO simulation assumptions is presented in in Volume V.

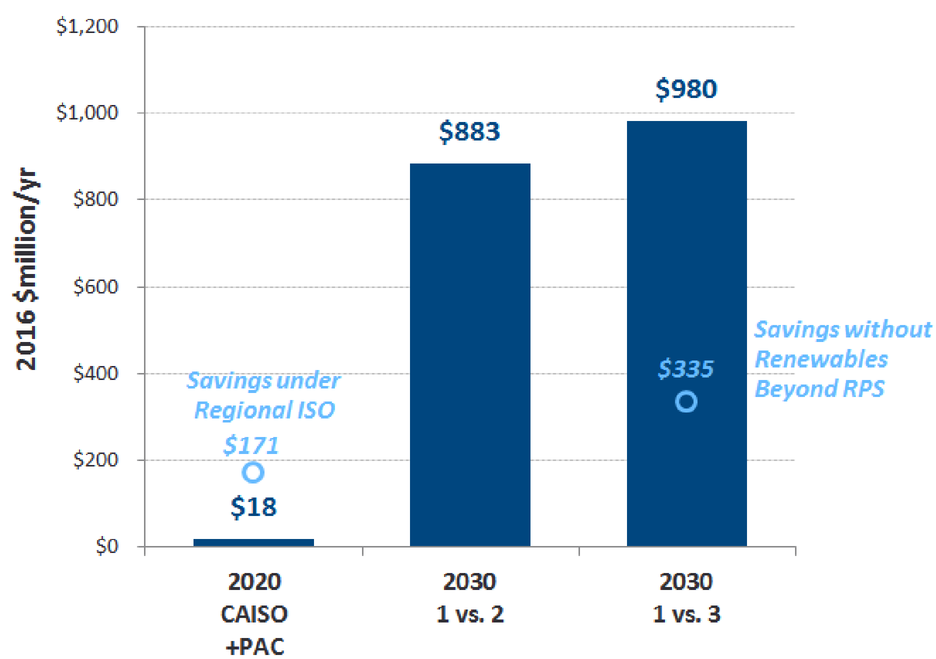
The five baseline scenarios reflect a 2020 and 2030 western wholesale electricity market with and without expanded ISO market operations, as described in Section I.B above. In the 2020 Current Practice and 2030 Current Practice 1 scenarios, we simulate a wholesale market that operates similarly to today's, with the CAISO-operated portion of California and the rest of the WECC system, consisting of 37 other balancing areas. The production cost simulations include economic and operational hurdles between WECC balancing areas, as well as limited sharing of generating capacity to meet operating reserve and load-following requirements. California's ability to sell oversupply from wind and solar resources is limited by assumed bilateral trading barriers. In the three regional market cases—2020 CAISO+PAC, 2030 Expanded Regional ISO 2 (Regional 2), and 2030 Expanded Regional ISO 3 (Regional 3)—we eliminate the economic and operational trading hurdles among the areas within the assumed regional market footprint, consistent with actual system operations in an ISO-operated regional market. We recognize that the broader regional market footprint, which provides market access to the low-cost renewable generation within the WECC region, will facilitate the development of more renewable generation beyond states' existing RPS than under current practices, consistent with the comments recently provided by some of the renewable generation and environmental stakeholders and the experience to date from other regional markets with access to low-cost renewable generation. The specific assumptions for the five baseline scenarios are described in more detail in Volumes III and V. The regional market experience with integration and facilitation of renewable generation is discussed in Volumes XI and XII.

2. Simulated Production Cost Results

The market simulations show that the lower economic and operational hurdles of a regional market reduce region-wide production costs. Cost reductions are driven by more sharing of generating capacity to meet operating reserve requirements and better utilization of low-cost resources compared to current practice operations by individual Balancing Authorities. The additional wind and solar resources facilitated by a regional market, which have negligible variable operating costs and no emissions associated with their generation output, further reduce production costs, both on a WECC-wide basis and within California. We estimate the wholesale production cost across the WECC to assess the impacts of regionalization on system-wide operating costs. These impact the estimated cost reduction associated with lower fuel, variable O&M, and start-up costs. Even though SB 350 does not specifically require the study to assess the changes on production cost across the entire West, this metric is useful to develop a better understanding of how a Regional ISO would utilize and dispatch the resources on its system and how that change in dispatch would affect WECC-wide production costs.

The results of the simulated regional electricity system show that the WECC-wide production cost savings in 2020 are modest ($18 million per year) due to the very limited scope of the regional market (CAISO+PAC) and the conservative modeling assumptions employed (such as assumed optimal dispatch within existing balancing areas, normal system conditions, generic plant and fuel cost assumptions, and no transmission outages). In 2030, the simulations show significantly higher production cost savings, ranging from $883 million to $980 million per year (4.5–5% of total production costs) under the larger regional footprint (U.S. WECC without PMAs) and with the facilitation of additional renewable generation. These production cost savings are merely the reduction in variable generation costs; they do not represent net WECC-wide savings by themselves because they do not yet consider other benefits nor the cost of additional resources built. Nonetheless, the production cost savings results for individual areas within WECC are one component of ratepayer impacts in those areas. The estimated WECC-wide production cost savings results for the three baseline scenarios (and two sensitivities discussed below) are shown in Figure 6.

Figure 6: WECC-Wide Annual Production Cost Savings in 2020 and 2030
(Excludes emissions-related costs & incremental renewable investment costs)



As shown by the blue circles in Figure 6, the two sensitivity analyses of these 2020 and 2030 baseline results show that: (1) estimated 2020 production cost savings for the larger regional footprint (U.S. WECC without PMAs) are $171 million/year (1.1% of WECC-wide production costs), which shows that regional-market savings grow significantly as the market size expands beyond CAISO+PAC and more balancing areas are consolidated into a regional market; (2) 2030 regional market operations for Scenario 3 without the additional beyond-RPS renewables are estimated to yield $335 million in annual savings (1.7% of WECC-wide production costs), showing that the benefits of a large regional market more double as an increased amount of renewable generation needs to be integrated and balanced in the system.

3. Simulation Approach and Assumptions that Produce Conservatively Low Production Cost Savings

The estimated levels of production cost savings are conservatively low because of the simulation approaches and assumptions employed. Similar to most other prospective market integration studies, the limitations inherent in the simulations undertaken for this study will lead to conservatively low estimates of production cost savings. These limitations include:

- The production cost simulations are based on **normal weather, normal hydrology, normal load, and normal generation outages** without considering additional benefits during unusually challenging market conditions. Examples of such challenging conditions not simulated include the recent California Aliso Canyon-related system constraints, extreme weather patterns that could create large swings of power flows across a system, or draught conditions, limiting the availability of hydro resources. These types and other challenging conditions tend to significantly increase the benefit of larger regional markets.
- The simulations **do not consider** the additional transmission constraints on the power grid during **transmission-related outages**. During transmission-related outages, the system will be constrained, which means the greater flexibility provided by integrated regional market operations yields higher cost savings and improved reliability.
- We do not assess the benefits of improved **management of uncertainties** between day-ahead and real-time operations, only some of which will be captured by the Energy Imbalance Market. Having a larger regional market provides the system operator with a larger pool of resources to manage unexpected changes of generation and load between the day-ahead and real-time operations, thereby reducing costs, reducing the need for

reserves and ramping capability, and increasing reliability, particularly when integrating large amounts of variable generation.

- We do not include the additional value associated with more efficient **utilization of the existing grid** compared to current practices, which leave existing transmission capabilities underutilized by between 5–25%. For example, the significant congestion experienced on the California-Oregon border—historically causing congestion charges of $60-150 million/year—is not visible in the current practices simulations.[30] Such congestion charges are associated with scheduling constraints that prevent the use of the transmission system's full physical capability. We do not simulate any such scheduling constraints in the Current Practice scenarios. In a regional market, the constraints are relieved, thereby increasing the efficient use of existing grid beyond the impacts captured in our simulations.
- We do not assume that the improved incentives would improve **generator efficiency and availability** evident in regional markets.
- Other than through trading margins and CAISO bilateral export limits, the simulations **do not fully capture inefficiencies of current trading practices** in terms of less flexible bilateral trading blocks (*e.g.*, 16 hour blocks at 25 MW increments), contract path scheduling, and congestion caused by unscheduled power flows.
- The simulations **do not capture** any benefits achievable through improved regional coordination and **optimization of hydro power resources**. We have left hydro dispatch unchanged between the current practices and regional market cases, leaving out value associated with allowing the hydro resources to be dispatched optimally by the regional ISO (subject to their operating constraints) to reduce region-wide production costs.
- The simulations conservatively assume **perfectly optimized**, security-constrained unit commitment and dispatch **within every individual WECC balancing area** even under the Current Practice scenario. This assumption alone is estimated to understate regional market benefits by approximately 2% of total production costs, which would add approximately $200 million/year to 2030 production cost savings.[31]

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30 This will understate the inefficiencies measured in the current practices scenario and thus reduce the estimated savings achievable in a more efficiently-dispatched regional market.

31 See Volume XII. For example, Wolak (2011) found that even moving from a zonal market design (previous CAISO market design) to a security-constrained nodal market design offers benefits

Continued on next page

Just as many other regional market studies have adopted similarly conservative modeling assumptions, the magnitude of the estimated production cost savings in this study is within the range of savings found in other market studies. For example, most of the market integration studies relying on *prospective* analyses estimated production cost savings from implementing regional energy markets at 1–3% of total production costs (including when starting from EIM-type markets). In contrast, and as discussed further below and in Volume XII of this report, most ***retrospective*** analyses of regional market benefits (analyzing regions and time periods with more modest penetrations of intermittent renewable resources) have found production cost savings in the range of 2–8% of total production costs.

The higher benefits measured in retrospective analyses of regional market integration confirm the limitations and conservative nature of our estimated production cost savings. For example, a 2015 study by the Southwest Power Pool (SPP) analyzing the impact of moving from a region-wide energy imbalance market with de-pancaked transmission rates to a system with full ISO-operated regional market estimated incremental savings equal to 4.8% of total production costs, well beyond the 3.2% savings already achieved by SPP's prior region-wide imbalance market and elimination of pancaked transmission charges.[32]

F. IMPACTS OF A REGIONAL MARKET ON CALIFORNIA AND THE REST OF THE WEST

This section summarizes the results responsive to the specific study requirements set out in SB 350. These results show that a larger ISO-operated regional market can create significant value to California ratepayers, decrease overall GHG emissions in and outside of California, reduce environmental impact in California and elsewhere, increase jobs and economic activities in California, and improve the conditions of California's disadvantaged communities. These impacts are estimated to be small in 2020, with a very small increase in GHG emissions for the rest of WECC due to a slight increase in coal-fired generation outside of California. The benefits of a regional market increase significantly with the expansion of the market footprint, reducing emissions and the costs associated with the integration of larger amounts of renewable

Continued from previous page

approximately equal to 2.1% of production cost savings. A similar benefit has been documented for moving from a zonal to nodal market design in Texas.

32 See Volume XII. Many aspects of SPP resemble the WECC (on a smaller scale), with major load centers in one portion of the footprint (the southeast), distant areas with low-cost renewable generation (the Great Plains), and significant reliance on natural gas and coal-fired generation.

generation resources to meet California's 50% RPS. These longer-term emissions and cost reductions provide strong evidence that the creation and expansion of a regional ISO-operated market can create significant value for California and the western power market as a whole.

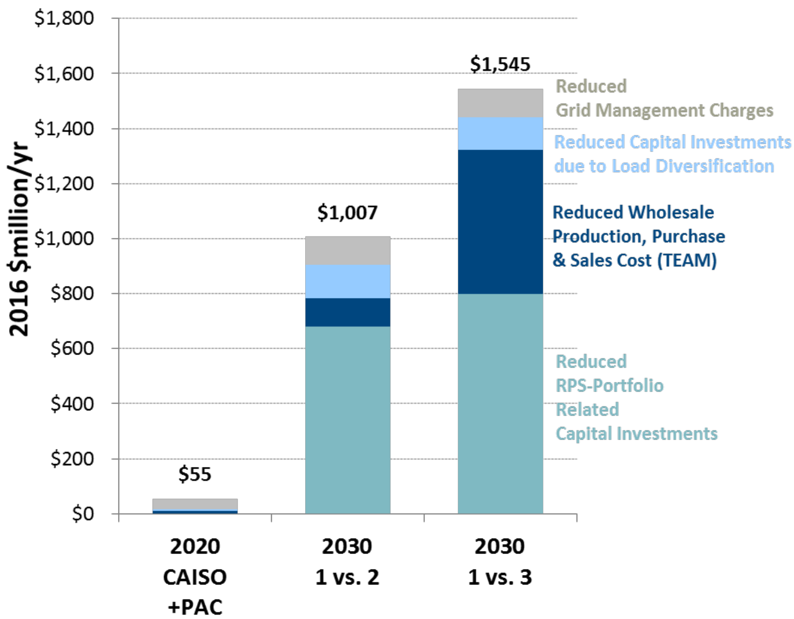
1. Overall Impact on California Ratepayers

To assess the impact on California ratepayers, we analyzed the extent to which regional market participation would affect annual cost of electricity supply for California customers. The analysis focuses on four main categories of costs that will be affected by expanding ISO-operations to a regional market:

- **Annual renewable procurement costs related to meeting California's 50% RPS:** These costs are estimated through RESOLVE model simulations, reflecting renewable investment and other fixed costs, including the costs of storage and transmission needed to integrate these renewable resources;
- **California's net costs associated with production, purchases, and sales of wholesale power:** These costs are estimated from production cost simulation results and by applying the CAISO's Transmission Economic Assessment Methodology (TEAM);
- **California's capacity cost savings from regional load diversity:** These costs are based on an analysis of the diversity of historical hourly load patterns, and the associated cost savings are based on the reduction in generating capacity needed to meet the lower region-wide coincident peak load (compared to the sum of individual balancing areas' peak loads); and
- **Reduction in Grid Management Charges (GMC) to California ratepayers:** These costs are estimated based on projected ISO revenue requirement for operating a regional market, and the savings are driven by the lower average rates estimated for system operations and market services in a larger footprint.

As summarized in Figure 7 below, the analysis of California ratepayer impacts from an expanded regional market shows estimated annual net savings of $55 million/year (0.1% of retail rates) in 2020 under the CAISO+PAC scenario compared to the 2020 Current Practice baseline. These annual net savings are projected to grow to $1.0–$1.5 billion/year (2–3% of retail rates) by 2030 for the expanded regional footprint (U.S. WECC without PMAs). The lower end of this range is associated with a continued focus on in-state procurement of renewable resources to meet the state's 50% RPS (Regional 2), while the higher end of this range is associated with a renewable procurement approach that relies on more out-of-state resources (Regional 3). These estimated ratepayer benefits are annual net benefits, estimated for the years 2020 and 2030. If the regional market grows as assumed in this study, the $55 million/year annual savings in 2020 are expected to grow over time to $1.5 billion/year in 2030. Since these annual ratepayer benefits are associated with true cost reductions, they are expected to be sustained over the long-term, beyond 2030.

Figure 7: Estimated Annual California Ratepayer Net Benefits



As shown in Figure 7 (the bottom portion of the 2030 bars), approximately $680–$800 million of the estimated savings in 2030 are associated with the reduction in the **annual capital investment costs related to the renewable procurement** necessary to meet California's 50% RPS. The range of the RPS-portfolio-related annualized investment costs savings depends on California's willingness and ability to rely on lower-cost renewables from outside of California (Regional 2 vs. 3) and the costs associated with building the transmission needed to deliver the resources to the expanded regional market. Under the 2030 Current Practice 1 scenario, the annual costs of procuring the necessary renewable resources increase as renewable curtailments increase and the need to build more renewables to meet the RPS requirements increases with it. The costs of procuring renewable resources decrease if California were able to export more of the oversupply under the current practices bilateral trading model (as estimated for a high-flexibility Current Practice 1B sensitivity, as discussed further below). Further details on underlying modeling approach, key input assumptions, sensitivity analyses, and results are provided in Volume IV.

As shown in the dark blue slices of the bars in Figure 7, we estimated that the expansion of the regional market will create 2030 annual savings of $104–$523 million/year associated with California's **net costs of production, purchases, and sales** of wholesale power. This portion of the 2030 California ratepayer savings comes from: (a) lower production costs of owned and contracted generation to meet load; (b) reduced purchase costs when load exceeds owned and contracted generation (higher in Regional 2 with more REC-only purchases); and (c) higher revenues when selling into the wholesale market during hours with excess owned and contracted generation (we conservatively assume power is sold at no less than $0/MWh in these baseline estimates). The production and purchase/sale cost impacts capture the increased efficiency of trades due to de-pancaking of transmission charges, reduced operating reserves, regionally optimized unit commitment, and economically-optimized dispatch of generation in the day-ahead market, subject to the available transmission capabilities. Further details on production cost simulations and the calculation of California costs associated with production, purchases, and sales under the TEAM approach are provided in Volume V.

As shown by the third (sky blue) slice of the bars in Figure 7, the integration of existing balancing areas into a broader ISO-operated regional market yields savings related to **load diversity**, allowing for the reduction of investments in resources necessary to meet system-wide and local resource adequacy requirements. These resource adequacy-related benefits of load diversity can be assessed from either a reliability perspective (*e.g.*, by holding generation investments constant and analyzing the benefit of improved reliability) or from an investment-cost perspective (*e.g.*, by holding the level of reliability constant and analyzing the reduction in generation investment needs). For this study, we estimated the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity costs due to larger regional market. Because each of the individual balancing area within the market region experiences peak loads at different times, the coincident peak load for the combined region is lower than the sum of the individual areas' internal peak loads. Accordingly, the expanded regional market is estimated to reduce California's own resource adequacy capacity needs by 184 MW in the 2020 CAISO+PAC scenario with annual capacity cost savings of $6 million/year, and by 1,594 MW in 2030 under the expanded regional footprint (U.S. WECC without PMAs), with conservatively-estimated annual savings of $120 million/year. Further details on our load diversity analyses, including data used, key assumptions, and findings are discussed in Volume VI.

The top grey slice of the bars shown in Figure 7 is the estimated California ratepayer benefits associated with the **cost of ISO operations**. The total costs of grid management would increase with the expansion of the regional market, but these costs would be paid by a much larger group of customers within the expanded market region, resulting in reductions of the average GMC rates paid by California and other regional market customers. The expansion of the regional market is estimated to reduce the average GMC rates by 19% in 2020 under the CAISO+PAC scenario (relative to the 2020 Current Practice scenario), creating $39 million of annual savings for California ratepayers. These GMC savings increase to 39% in 2030 under the expanded regional footprint (U.S. WECC without PMAs) with California ratepayers' annual cost reductions increasing to $103 million/year. Further details on the calculation of Grid Management Charges and the associated California impact of a regional ISO-operated market are included in Section F of Volume VII of this report.

The expansion of the CAISO into a larger regional market would also affect the **allocation of existing transmission costs and new transmission investments**, both of which will depend on how those allocations are negotiated as a part of the regional market design. For the purpose of this study, we have assumed that: (1) existing transmission costs for each area will be recovered from each area's local load; and (2) the cost of additional transmission needed to achieve public policy goals will be allocated to the areas with those public policy goals. Currently, California customers pay for existing out-of-state transmission that is needed to support the prevailing power imports and delivery of generation from joint-owned plants that they have purchased (although some of those transmission costs may be bundled with power purchase costs). Such transmission costs associated with imports from neighboring areas, currently paid for by California, are offset in part by "wheeling" revenue associated with power exports to neighboring areas. In a regional market, California would no longer need to pay for transmission associated with imports from elsewhere in the regional market. However, the state would also no longer benefit from revenues associated with exports that serve load in the larger regional footprint (although California would still benefit from wheeling revenue for exports to areas outside the regional footprint). Our analysis assumes that the benefits of reducing transmission costs associated with imports would be fully offset (on average) by the wheeling revenues for

California's existing regional transmission facilities that exporters would continue to pay in the Current Practice scenarios.[33]

With respect to imports of additional renewable resources developed to meet the 50% RPS mandate (and as explained further in Volume IV), we assumed (and have reflected in the estimated renewable procurement costs) that: (1) any costs associated with new transmission needed to integrate these new resources would be allocated to California loads (particularly relevant in the Regional 3 scenario with increased reliance on out-of-state resources); and (2) California loads would benefit from a regional market's de-pancaked regional transmission charges only to the extent that the additional renewable resources can be delivered over the existing transmission grid (without additional transmission upgrades). Renewable projects developed beyond RPS needs are assumed to include in their contract prices with voluntary buyers any transmission interconnection-related costs (to reach local transmission hubs) and increased curtailment risks (to the extent the local and regional transmission grid cannot fully accommodate their output without transmission upgrades).

The components of ratepayer impacts in both annual dollar amounts and average California retail rates are tabulated in Figure 8. The overall savings from an expanded regional ISO-operated market are estimated to decrease average California retail rates by 0.4–0.6 ¢/kWh or by 2.0–3.1%.

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33 The production cost simulation results for 2030 show that California remains predominately a net-importer in over 80% of all hours of the year and the average quantity of imports exceeds those of exports, which further supports the assumption that foregone transmission wheeling revenues for exports would be more than offset by avoided transmission costs for imports.

Figure 8: Summary of California Ratepayer Impacts

		2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Base Costs	($MM)	$35,564	$35,564	$39,285	$39,285	$39,285
Incremental RPS-Portfolio Related Capital Investment	($MM)	$0	$0	$3,292	$2,612	$2,492
Production, Purchase & Sales Cost (TEAM)	($MM)	$7,752	$7,742	$8,066	$7,962	$7,544
Load Diversification Benefits	($MM)	$0	($6)	$0	($120)	($120)
Grid Management Charges Savings	($MM)	$0	($39)	$0	($103)	($103)
Cost of Electricity Supply to California Customers	**($MM)**	**$43,316**	**$43,262**	**$50,643**	**$49,636**	**$49,098**
Impact of Regionalization	($MM)		($55)		($1,007)	($1,545)
	(%)		(0.1%)		(2.0%)	(3.1%)
Total Sales	(GWh)	260,028	260,028	256,404	256,404	256,404
Average Cost to California Customers	**(cent/kWh)**	**16.7**	**16.6**	**19.8**	**19.4**	**19.1**
Impact of Regionalization	(cent/kWh)		(0.0)		(0.4)	(0.6)
	(%)		(0.1%)		(2.0%)	(3.1%)

These California ratepayer impacts were tested under alternative sets of assumptions to understand the sensitivity of results to of some of the key drivers. These sensitivity analyses include the following:

- The **"2020 Expanded Regional ISO"** sensitivity shows that annual California ratepayer benefits would be $258 million/year in 2020 for the expanded regional footprint (U.S. WECC without PMAs). This is much higher than the $55 million/year estimated for the smaller regional CAISO+PAC market scenario, but remains below the 2030 benefits due to the limited benefits associated with procurement and integration of renewable resources (with essentially all of the renewables to meet 33% RPS in 2020 are under contract).
- The **"2030 Current Practice 1B"** sensitivity assumes higher flexibility in bilateral markets with CAISO's net bilateral export capability increased from 2,000 MW to 8,000 MW. This high-bilateral-flexibility case assumes that bilateral markets would accommodate the re-export of all prevailing existing imports (ranging from 3,000 to 4,000 MW per hour) plus export an additional 8,000 MW of (mostly intermittent) renewable resources. The results for Sensitivity 1B shows that even when oversupply conditions can be managed more flexibly without a regional =market, the 2030 annual California ratepayer benefits of a regional market would still range from $767 million/year (for Regional 2) to $1.4 billion/year (for Regional 3).
- A sensitivity allowing for **"Negative Bilateral Settlement Prices"** captures the impact of negative hourly prices during oversupply and renewable curtailment conditions. The

baseline calculations assume power from California resources is exported and sold at no less than $0/MWh. At a price of zero California would be giving power away for free, but these sales to outside parties during oversupply conditions do not impose additional costs on California ratepayers. If that oversupply needs to be sold at negative prices, California would have to pay counterparties to take the power exported out of California. Such negative prices are a likely future outcome, consistent with the recent experience in CAISO during periods with high solar generation,[34] at the Mid-Columbia trading hub during high hydro and low load periods, and in other markets (such as ERCOT, MISO, and SPP) that have been experiencing renewable generation oversupply conditions. The sensitivity results show that experiencing negative $40/MWh prices during any oversupply and renewable curtailment periods would increase California's 2030 annual regional market savings by $133–$209 million/year.

- In response to stakeholder feedback, we also estimated California ratepayer impacts for a **"Scenario 3 without Beyond-RPS Renewables,"** which eliminates the impact of the assumed 5,000 MW of additional low-cost renewable generation investments facilitated by a regional market beyond RPS mandates. Eliminating all of the 5,000 MW of assumed beyond-RPS renewables from Regional 3 scenario increases regional market prices slightly, which in turn increases the cost of California's power purchases by a small amount. The net effect is a reduction of annual ratepayer benefits from $1.545 billion/year to $1.522 billion/year.

Figure 9 below summarizes California ratepayer impacts for the three baseline scenarios and the sensitivity analyses discussed above. As this figure shows, the overall benefits to California ratepayers are robust, ranging from over $700 million/year to $1.7 billion/year by 2030.

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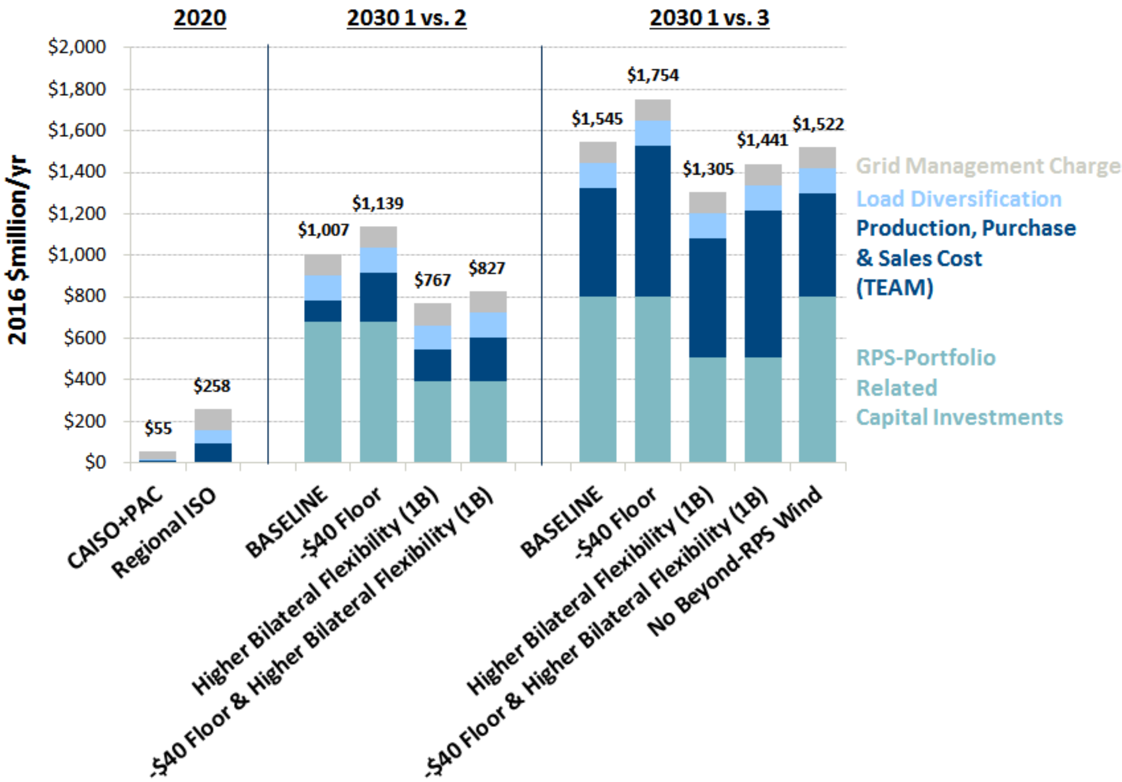
[34] Negative prices are already being experienced during real-time operations in the CAISO footprint. For example, 7% of all 5-minute real-time pricing intervals have experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation and relatively low loads. Although some prices ranged between negative $30/MWh and negative $150/MWh, in most of the periods, the negative prices remained above negative $30/MWh. (See CAISO Internal Market Monitor "Q1 2016 Report on Market Issues and Performance.")

Figure 9: Estimated Annual California Ratepayer Benefits in Baseline Scenarios and Sensitivities



These estimates of California ratepayer savings are understated because they do not include the value of other regional-market-related benefits. Overall, the study relies on assumptions that err on the side of showing lower benefits than will likely materialize in a regional market to ensure that the estimated benefits are not overstated. The values that have not yet been quantified include:

- A wide range of reliability-related benefits offered by a regional market as discussed further in Volume XI. These reliability benefits relate to improvements in regional reliability operations, compliance, and planning, including reliability benefits from improved real-time price signals, congestion management, unscheduled flow management, regional unit commitment, system monitoring and visualization, backup capabilities, operator training, performance monitoring, procedure updates standards development, NERC compliance, regional planning, fuel diversity, and long-term investment signals.
- Improved use of the physical capabilities of the existing grid both on constrained WECC transmission paths and within the existing WECC balancing areas.

- Improved regional and interregional transmission planning to increase efficiency and cost-effectiveness of the transmission buildout across the West.
- Improved risk mitigation from a more diverse resource mix and larger integrated market that can better manage the economic impacts of transmission and major generation outages and better diversify weather, hydro, and renewable generation uncertainties.
- Long-term benefits from stronger generation efficiency incentives and better long-term investment signals across a larger regional footprint.

The specific study assumptions that lead to conservatively low estimates of ratepayer benefits include:

- **Understated Renewable Investment Cost Savings.** In the development of the 50% renewable resource portfolios, E3 employed a number of assumptions that, overall, tend to understate the potential benefits of a regional market. For example, it is assumed that a number of renewable integration solutions are in place under current practice by 2030, despite the fact that some of these solutions are significantly more costly than a regional market (which returns positive net benefits even before renewable integration is considered). These integration solutions include time-of-use rates, 5 million electric vehicles with near-universal access to workplace charging, 500 MW of new pumped storage, 500 MW of geothermal are added to the portfolio in all scenarios, displacing approximately 1,500 MW of wind or solar resources that would otherwise have been needed, thereby reducing the renewable integration burden under Current Practice 1. The study further assumes that (1) 5,000 MW of out-of-state renewable resources can be delivered for meeting California RPS over existing transmission, providing diversity to the portfolio and significantly reducing the renewable integration burden under Current Practice 1; (2) energy-only resources are the dominant form of contract in future renewable procurement, eliminating the need for any new transmission in California to meet the 50% RPS under the Current Practice 1 scenario. These and other renewable-portfolio-related study assumptions are discussed further in Volume IV.
- **Understated Production Cost Savings.** As discussed in the Production Cost Simulation section above, the simulations use data from a year with "normal" weather, hydroelectric conditions, and loads for the entire WECC area. Under these "normal condition" assumptions, the value of a regional market will be more modest. The value of a regional market can be dramatically larger under challenging market conditions, such as heat waves, cold snaps, transmission outages, or fuel supply disruptions (*e.g.*, Aliso Canyon

impacts). We have assumed that ISO-like optimized commitment and dispatch would exist within each of the existing balancing areas even under current practices, when in reality, most balancing areas do not employ such security-constrained optimal unit commitment and dispatch. Moreover, and aside from the inefficiencies reflected in the hurdle rates, the simulations assume that bilateral trading is perfectly efficient and the scheduling and utilization of the transmission system is optimal, when in reality, much of the transmission congestion recorded is due to scheduling inefficiencies that create transmission congestion when the grid could be utilized more fully but for the imperfect bilateral scheduling processes. Similarly, the study does not fully account for improved regional optimization of hydro resources, which would further improve the renewable integration benefits of a regional market. These and other production-cost-related conservative study assumptions are discussed further in Volume V.

- Understated Load Diversity Benefits. We do not estimate the financial value associated with the reliability improvements due to load diversity in a larger regional market. We do not consider the additional benefits that would accrue to California given the possible retirement of additional existing generation in California, which would increase the demand and value resource adequacy capacity and thereby increase the value of load diversity. These and other load-diversity-related conservative study assumptions are discussed further in Volume VI.

2. Impact on Emissions of Greenhouse Gases and Other Air Pollutants

The study team analyzed the impact of expanded regional ISO-operations on California's and WECC's emissions of air pollutants by the electric sector. The estimates are based on detailed fuel use and generating unit outputs simulated by the production cost model.[35] The main objective of this analysis was to measure a regional market's overall impacts on annual CO_2 emissions from the power section in California and in the rest of WECC, and to estimate location-specific shifts in NOx, SO_2, and PM2.5 emissions within California (including emissions-related impacts on disadvantaged communities as discussed further below).

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35 As noted earlier, the GHG analysis only considers emissions from power plant operations; it does not consider other sectors of the economy or life-cycle effects from the manufacturing and construction of renewable resources or transmission lines. It does, however, consider the effect of new generation on the dispatch of all generating resources across WECC.

Since the individual generating units modeled in the production cost simulations largely reflect generic emissions rates and generic heat rate assumptions developed by WECC stakeholders in the Transmission Expansion Planning Policy Committee, the accuracy of the resulting CO_2 emissions are limited by the accuracy of the resource-specific input assumptions. For NOx, SO_2, and PM2.5 emissions, the study team developed emissions rates by fuel and generating unit type, including during unit startup, based on industry studies and California generating unit air permits.[36,37]

In general, the emissions results show that regional markets provide the operational mechanisms for more efficient use of fossil fuels and facilitate accelerated renewable energy generation investments beyond those needed to meet the region's RPS mandates. As a result, an expanded regional market is estimated to decrease over time the electric sector's use of fossil fuels in California and the rest of the WECC.[38] A summary of these regional market scenarios' impacts on estimated generation dispatch is shown in Figure 10 below.

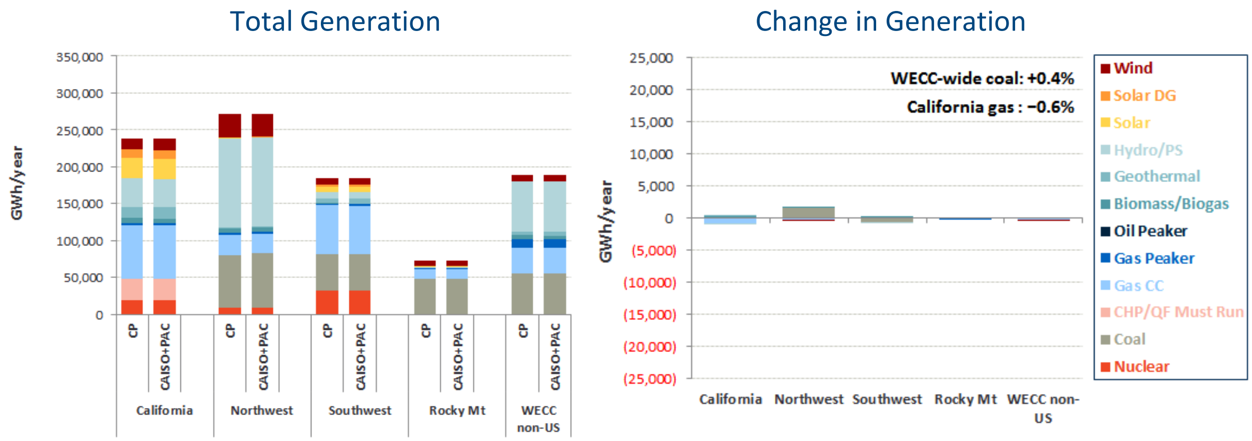
36 The production cost model does track unit-specific NOx and SO_2 emissions. However, as with most or all production cost models there are some limitations to interpreting absolute levels of unit-specific air emissions as explained in footnote 23.

37 NREL (2013). The Western Wind and Solar Integration Study Phase 2. Technical Report. NREL/TP-5500-55588. http://www.nrel.gov/docs/fy13osti/55588.pdf

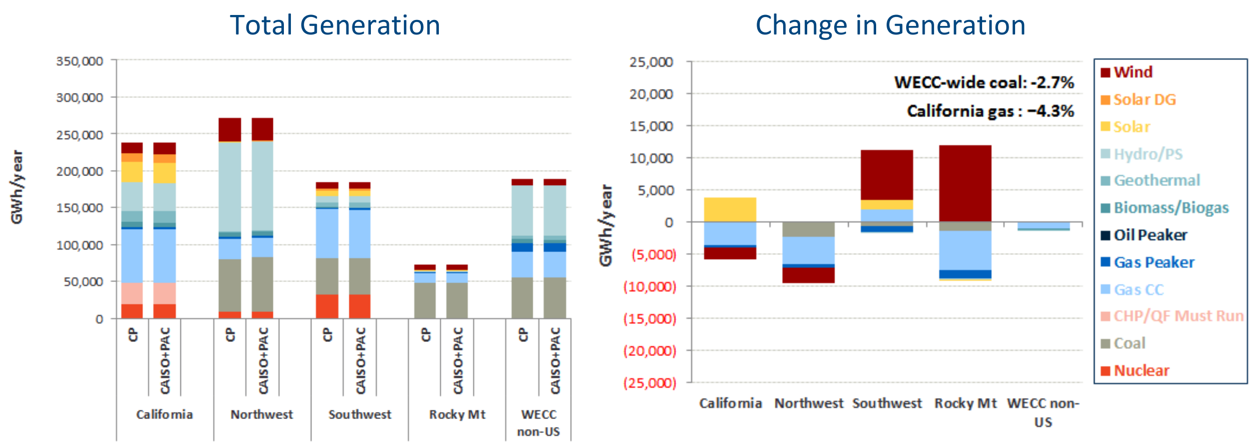
38 This study is focused on the changes in emissions associated with the deployment and the operational use of the power generation resources, and, accordingly, this study assesses the effects of regional market on those uses. To the extent that less natural gas is used for electricity production due to regional market, this study does not include an assessment of how such fuel use reductions might also increase environmental benefits due to decreases in upstream methane emissions.

Figure 10: Simulated California and WECC-Wide Generation by Type

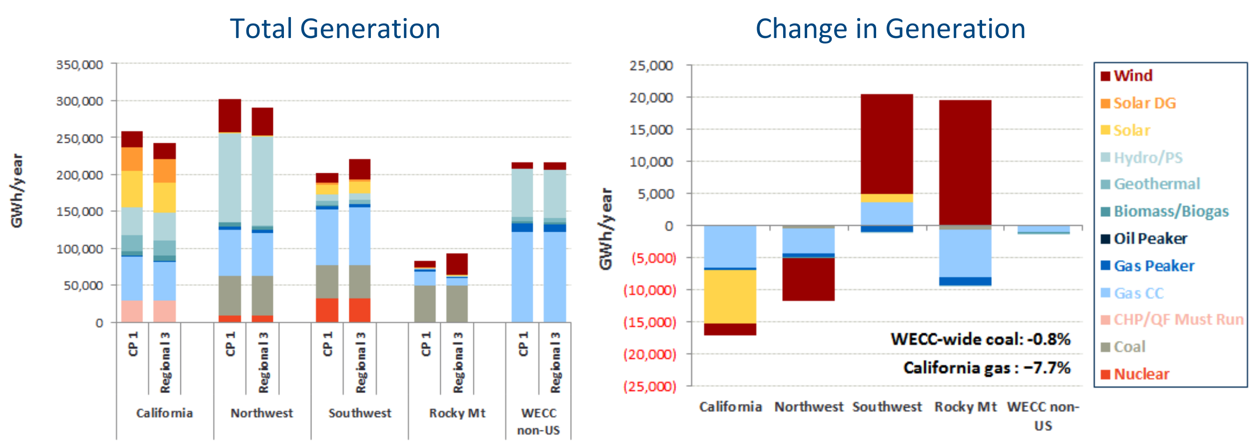
(a) 2020 Current Practice versus CAISO+PAC



(b) 2030 Current Practice 1 versus Regional ISO 2



(c) 2030 Current Practice 1 versus Regional ISO 3



a. *Impact on Coal Dispatch in WECC*

The simulations results for a regional market limited to only CAISO and PacifiCorp in the near-term show a very small increase in coal-fired generation. In particular, our simulations show a small 0.4% increase in coal-fired generation, as PacifiCorp's coal fleet is assumed to face lower economic and operational hurdles to meeting California loads within a regional market. However, several factors need to be considered in the interpretation of these results, the sum of which likely would more than offset this simulation result.

First, the increase in 2020 simulated coal plant dispatch is very small, resulting in only a 0.2% increase in WECC-wide carbon emissions. It would only require the retirement of a single small coal generating unit or the addition of 150-300 MW wind generation on a WECC-wide basis to more than offset this effect.[39] As discussed further below and in Volume XI of this report, regional markets have shown to facilitate renewable generation investments at a substantially faster rate than non-market regions. For example, the ISO-operated markets in Texas and the Midwest have seen 24,000 MW of new wind generation investment over the last 5 years, most of which has been added based on voluntary contracts beyond RPS mandates.

Second, the broader regional footprint would expose coal-fired generation in PacifiCorp (and in the rest of the regional footprint) to more competition from regional renewable generation (RPS-based and beyond-RPS) and efficient natural gas-fired generation. Regional markets with access to low-cost renewable resources in the eastern part of the U.S. show that the markets attract significant additional renewable resource investments, which in turn put downward pressure on energy prices in the wholesale market and thereby increase the financial pressure on coal-fired plants (which already face the economic challenge of competing with gas-fired power plants due to low natural gas prices). Our 2030 results reflect that as an expanded Regional ISO facilitates additional renewable generation development beyond RPS mandates, the increased renewable generation decreases the dispatch of natural gas- and coal-fired generation—fully consistent with the experience in regional markets in the eastern part of the U.S. For example, as noted by SPP's CEO, "…since wind and solar facilities do not have fuel costs like fossil fuel plants, big increases in their generation shares would be expected to push down prices in the

39 The total 2020 simulated WECC-wide increase in coal-fired generation is about 900 GWh for the year, or the equivalent of an approximately 80 MW coal plant. The range of wind generation needed to displace the amount of CO_2 output from the increased coal dispatch depends on the ratio of coal and gas generation displaced by the additional amount of wind.

day-ahead and real-time markets…. If and when that happens, prices could dip so low that many of the larger fossil fuel plants would struggle to clear market auctions, pushing them toward retirement.”[40]

Third, the small increase of coal-fired generation shown in the 2020 simulation results is in large part related to modeling simplifications. PacifiCorp’s coal fleet is not assumed to be under contract to meet California load. The additional dispatch of coal-fired generation in the 2020 regional market simulations is therefore assumed to be purchased in the spot market and registered as an “unspecified” import according to the California Air Resources Board’s current GHG accounting procedures. As an unspecified import, our simulations assume PacifiCorp’s coal fleet faces a carbon cost to serving California load that is based solely on the generic emissions rate of a natural gas-fired combined-cycle plant. In reality, however, the incremental dispatch of the coal-fired generating units would be visible to the ISO (as it is under EIM operations) and, therefore, the ISO would be in a position to assign the appropriate levels of CO_2 costs to any imports from these generating units. By assuming a natural gas-based carbon cost to all imports that are not under contracts, the simulations understate the operating cost of coal-fired plants by approximately $10/MWh. When unit-specific CO_2 cost are applied to PacifiCorp’s coal fleet, as would likely be the case when serving California load in the ISO-operated regional market, that would significantly reduce (if not entirely eliminate) the small increase shown in our 2020 simulations.[41]

Moreover, the competitive pressures imposed by regional markets leads to another impact on coal-fired plants that is not captured in our market simulations. The current practice of at least some coal-fired plant owners is to operate them in a must-run fashion as “baseload” facilities, dispatching them whenever physically available. These must-run operating preferences tend to change significantly when exposed to the competitive pressures and pricing transparency of a regional market and replacement purchases are available at regional market prices whenever needed. For example, Great River Energy (a cooperative utility operating in the wind-generation-rich MISO market) recently decided that it “would no longer keep [its] Stanton [coal

[40] Gavin Blade, “SPP CEO: Regionalization, transmission help push renewables penetration near 50%,” UtilityDive, May 26, 2016.

[41] To analyze this question we tested a 2020 simulation with a carbon cost for unspecified import equal to the average of a coal plant and a natural gas-fired combined cycle plant. This carbon import cost based on a 50/50 coal/gas emissions rate reduced the small increase in the 2020 baseline cases by half.

plant operating] as a must-run plant."[42] As the president of that North Dakota plant (which, like many coal plants in the WECC, is fueled with coal from the Powder River Basin) explained: "We felt like we were economically forced into this. We need to do what's in the best interest of our members, so we're not operating the plant at a time when we're not even getting paid for the coal we're burning…. We're really affected by whether the wind blows."[43] Similarly, as SPP's CEO noted "SPP has seen some big changes in how its fossil fuels are deployed. Coal plants…are being dispatched less often, while fast-ramping natural gas plants are taking up a larger portion of the generation share to help compensate for the variability of wind power."[44]

The market simulations do not capture the extent to which some of the western coal plants would likely be operated as "baseload" or "must-run" plants by their owners under the 2020 or 2030 Current Practice scenarios. This will understate coal-fired plant dispatch and carbon emissions in those 2020 and 2030 Current Practice cases and thus not fully capture the extent to which competitive pressures and improved pricing transparency would lead some plant owners to modify the baseload, must-run operations of their coal-fired plants.[45]

As a regional market facilitates the additional development of low-cost renewable resources, the reduced market prices and coal-fired plant dispatch, particularly when must-run operations end, would probably lead to additional coal retirements. This effect is likely to materialize given that a significant portion of WECC-wide coal-fired generation is located in areas with significant low-cost renewable resources that currently do not have access to a regional market. However, our simulation assumptions do not change the coal plant retirement assumptions between the current practice and regional market cases, which would underestimate the potential reduction of GHG emissions associated with the ability of regional markets to help facilitate the retirement

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42 Jessica Holdman, "Coal power struggles in competitive energy market," Bismarck Tribune, April 16, 2016.

43 *Id.*

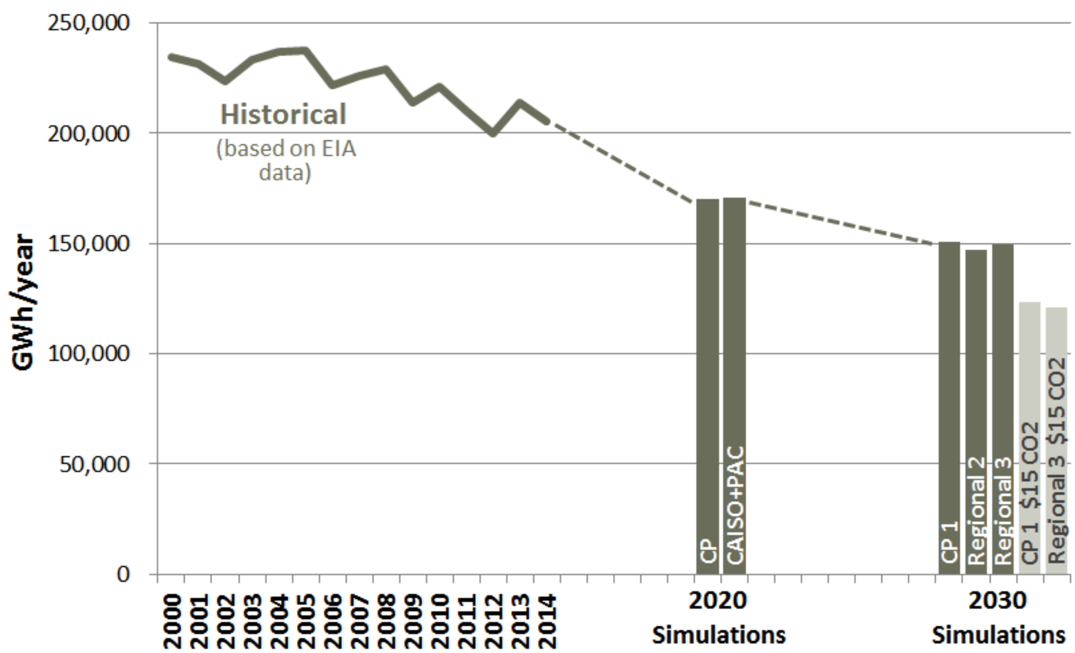
44 Gavin Blade, "SPP CEO: Regionalization, transmission help push renewables penetration near 50%," UtilityDive, May 26, 2016.

45 Possible candidates for such market-facilitated modifications of must-run operations are units that were operated historically as baseload plants. In our 2020 Current Practice simulations, some large coal plants that were historically dispatched at a 75-85% annual capacity factor are dispatched economically only in the 0-50% range. While operations at such lower annual output levels would likely require renegotiating the plants' fuel contracts, participation in a regional market would: (1) make the potential to reduce "out of market" cost of continued baseload operations more visible and (2) make lower-cost replacement power (and operating reserves) more readily available.

of coal generation. These effects have already become realities in eastern regional markets where the increased economic pressure on coal-fired plants has forced, and is continuing to force, more to retire—particularly in areas with significant renewable generation development and when faced with additional costs, including retrofitting the plant to comply with environmental regulations. This phenomenon has already been observed in the other regional markets even without CO_2 costs imposed by regulatory policies.

Figure 11 compares the simulated impact of the regional market on coal plant dispatch to: (1) historical fluctuations of annual coal-fired generation across WECC; (2) the projected overall trend of coal-fired generation in the region through 2030; and (3) the impacts of environmental regulations, such as a modest carbon price that would allow the rest of the WECC region to achieve CPP compliance. As the figure shows, the simulated 2020 levels of WECC-wide coal-fired generation are substantially less than average historical levels. By 2030, the simulated WECC coal-fired generation will be reduced even further. Importantly, Figure 11 shows that the estimated 2020 increase of coal plant dispatch in the CAISO+PAC regional market case is very small compared to both the projected long-term declines in coal-fired generation and the year-to-year fluctuations caused by varying weather, hydrology, and other market conditions.

Figure 11: Historical WECC Coal Plant Generation and Simulated 2020 and 2030 Coal Generation



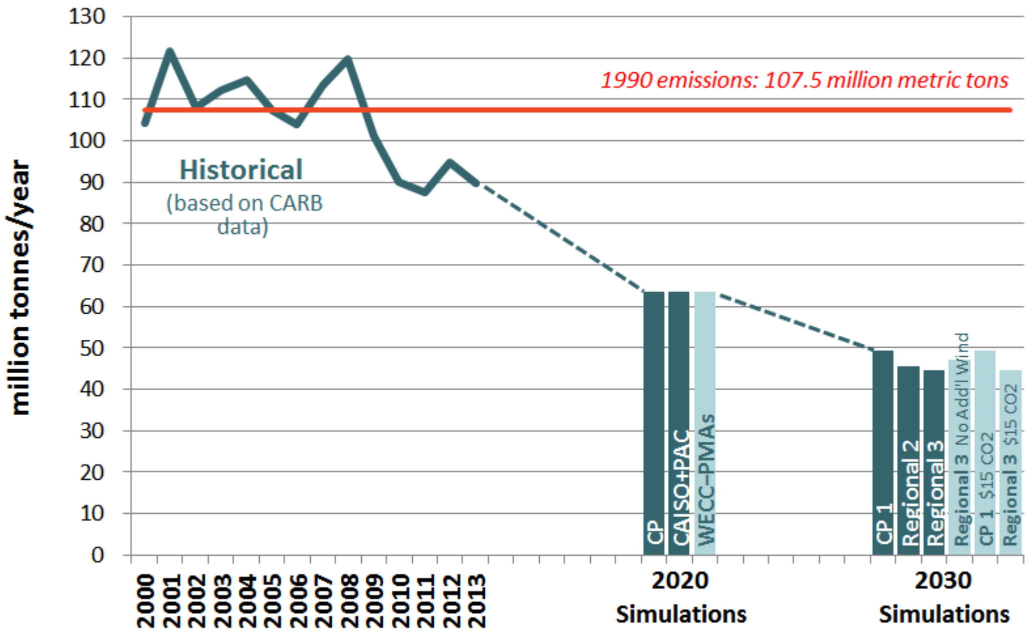
Despite the pressures on coal-fired plants created by expanding renewable generation in a regional market, the primary drivers of changes in the overall output of coal plants likely are the relative prices of fuel (coal versus natural gas) and environmental regulations. As discussed above, we did not make any assumptions about differences in coal plant operations between the Current Practice and regional market scenarios (e.g., we don't assume must-run operations under the Current Practice scenarios), and we did not implement any additional coal plant retirements due to the regional market. As a result, our regional market simulations do not show a significant impact on the overall level of coal-fired generation. Further, because our simulation holds the operational preferences and retirements of coal plants constant across all cases, the policy drivers have a much greater effects on the total regional coal-fired generation than the simulated impacts of regional market operations. For example, as the 2030 simulation results of a modest $15/tonne carbon price sensitivity for the rest of WECC show, the impact of such environmental regulations (the light grey bars on the right of Figure 11 above) show a much more significant impact on simulated coal-fired generation across the WECC.

b. California CO_2 Emissions Results

For California, we estimate CO_2 emissions in 2020 to be approximately 64 million metric tons, down from approximately 90 million tons in recent years. In terms of the simulated 2020 CAISO+PAC regional market impact, we find a small 0.2 million metric ton (0.3%) increase in 2020 CO_2 emission from in-state generation and imports in this CAISO+PAC scenario relative to the 2020 Current Practice scenario. The small increase, however, is not observed for CO_2 emissions associated with serving California load, which is equal to 63.6 million metric tons for both the 2020 Current Practice and CAISO+PAC scenario, after netting out small amounts of exports of California generation to serve load elsewhere. These 2020 results, along with 2030 results, are shown below in Figure 12 (with historical CO_2 emissions) and Figure 13 (with accounting for exports to neighboring regions).

To put the 0.2 million metric ton increase in 2020 into perspective, even if that small amount of CO_2 emissions increase were to materialize due to an inability to track source-specific CO_2 emissions associated with imports, the 0.3% increase is very small compared to the much larger swings in the amount of California power sector-related CO_2 emissions due to changes in weather patterns and hydro availability from year to year. Figure 12 below shows this historical pattern (on the left-hand side of the graph) in comparison to the 2020 and 2030 simulation results for the baseline scenarios and various sensitivities. As shown, the year-to-year fluctuation of electricity sector CO_2 emissions due to variations in weather and hydro conditions can swing by 10 to 20 million metric tons, which is very large compared to the 0.2 million metric ton simulated increase in 2020 California CO_2 emissions. Further, even if the 0.2 million metric ton increase in simulated 2020 California CO_2 emissions were to materialize, that amount would be more than offset by adding a small amount of renewable resource or by additionally retiring a small coal plant associated with serving California loads or elsewhere in WECC.

Figure 12: Historical and Simulated California Electricity Sector CO_2 Emissions



Note: In 1990, California electricity sector CO_2 emissions were 107.5 million metric tons. Compared to this historical benchmark, projected emission levels are approximately 40% lower in 2020 and 55-60% lower in 2030.

As illustrated in Figure 12 above and Figure 13 below, the production cost simulations show significant California electricity sector CO_2 emissions reductions between 2020 and 2030, even before considering the impacts of a regional market. These emissions reductions are associated with: (a) the addition of renewable energy resources to meet California's and other western states' RPS through 2030, (b) retirement of once-through-cooling gas generators, and (c) increasing CO_2 prices in California. The resulting 2030 CO_2 emissions associated with serving California electricity load are estimated to be range from 45-50 million metric tons, which is approximately 55–60% below 1990 levels of 107.5 million metric tons.[46,47]

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46 It is important to note that we only measure CO_2 emissions impacts in the electric sector, and that a decrease in electric sector CO_2 emissions does not necessarily mean a decrease in the economy-wide emissions covered under California's greenhouse gas cap-and-trade system. We also note that, although carbon emissions of power plant generation were estimated, the impacts on GHG emissions

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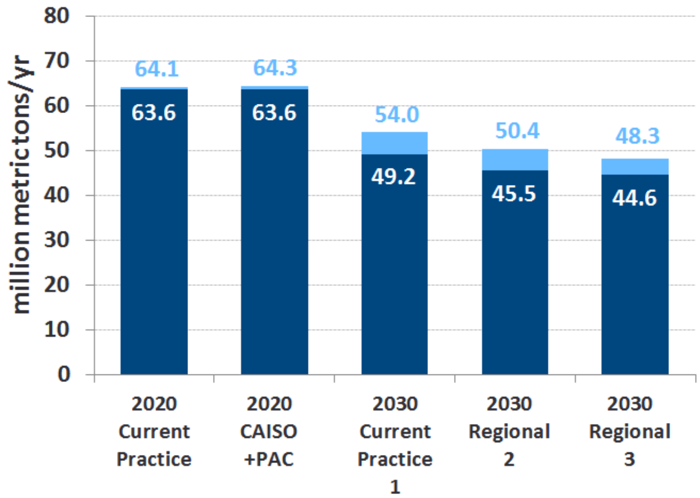
Figure 13: Simulated California Electric Sector CO_2 Emissions



Note: The higher value reflects the current CARB's GHG accounting for GHG imports. The lower value includes an adjustment to "credit" California for GHG impacts associated with exports, which is not currently part of the CARB's accounting.

In 2030, as shown in Figure 13 above, the expanded regional market would reduce California's CO_2 emissions associated with serving the state's electricity load by 4 to 5 million metric tons (8%–10% of the state's simulated total electricity sector emissions). As shown in the light blue slices of the figure, the magnitude of CO_2 emissions attributed to serving California load depends in part on how emissions related to power exports are accounted for. If the CO_2 reduction in the rest of WECC caused by exports of California renewable resources during oversupply conditions is taken into consideration as a credit, the net carbon emissions attributed to California loads are reduced by approximately an additional 5 million metric tons in all simulated cases. While we recognize that this export adjustment is not currently part of CARB's administrative carbon

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of manufacturing more or fewer renewable resources that would be needed in different scenarios (due to differences in energy curtailments) and the construction of new transmission to support Scenario 3 were not examined separately. Our results do not include any such manufacturing and construction-related GHG emissions.

[47] As discussed further below, calculations for California assume CO_2 emissions associated with imports are charged, and exports are credited, based on a generic emissions rate for natural gas combined-cycle plants. Crediting for exports is not currently part of the administrative accounting rules for California's greenhouse gas cap-and-trade system. We credit exports to better represent emissions attributable to California loads. As shown below, even at the 50% RPS level achieved in 2030, the credits for exports are relatively small, representing about 4-6 million metric tons compared to 45 million metric tons in 2030 statewide emissions.

accounting, the current accounting framework was not developed under conditions where California was expected to export significant quantities of renewable energy.[48]

c. WECC-Wide CO_2 Emissions Results

Consistent with our discussion above regarding the long-term trends and impact of a regional market on coal plant dispatch, a regional ISO-operated market will help reduce CO_2 emissions from the power sector in California and across the WECC by dispatching more efficient generating units, facilitating the development of additional renewable resources (particularly in regions with where they tend to displace more carbon-intensive coal-fired generation), and facilitating the reduced dispatch and retirement of coal plants by providing increased pricing transparency and competitively priced power to the utilities who own these coal plants.

Figure 14 below summarizes the simulation results for WECC-wide CO_2 emission for the 2020 and 2030 baseline scenarios. As the figure shows, simulated emissions are 331.3 million metric tons for the 2020 Current Practice scenario and 331.9 million metric tons for the 2020 CAISO+PAC scenario, before declining to a range of 295.9 to 307.3 million metric tons in 2030.

The 0.6 million metric tons (0.18%) WECC-wide increase in the 2020 CAISO+PAC scenario compared to the 2020 Current Practice scenario relates to the coal plant dispatch issue discussed above. As also discussed above, our simulations do not fully capture all of the effects that would reduce CO_2 emissions from the power sector in a regional market setting. Given that our simulations do not reflect a number of emissions-reducing factors,[49] we find the 0.18% increase

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[48] In 2030, exports are driven by renewable oversupply that cannot be used serve California's load. Instead, the renewable exports displace generators that would need to run outside of California to serve external load. Accordingly, they reduce the GHG emissions in the rest of WECC footprint. GHG credits for exports are meant to recognize the "net" impact on global GHG emissions.

In addition, if California imported 1 MWh from one region in one hour and then exported 1 MWh to the same region in the next hour, the overall emissions outcome would be similar to a case in which California did not import or export any energy at all (assuming that marginal resources remain similar between the two hours). Applying a cost on imports and an offsetting credit on exports (such that the net cost is zero) would be more appropriate in this case regardless of whether the focus is on in-state GHG emissions or global GHG emissions.

We further note that this (in our opinion appropriate) treatment of export-related carbon is consistent with that applied in the CEERT/NREL Low Carbon Grid Study.

[49] As discussed earlier, among other modeling simplifications, the small CO_2 emission increase is due, in large part, to the simulation approach that does not allow assigning a higher generator-specific CO_2

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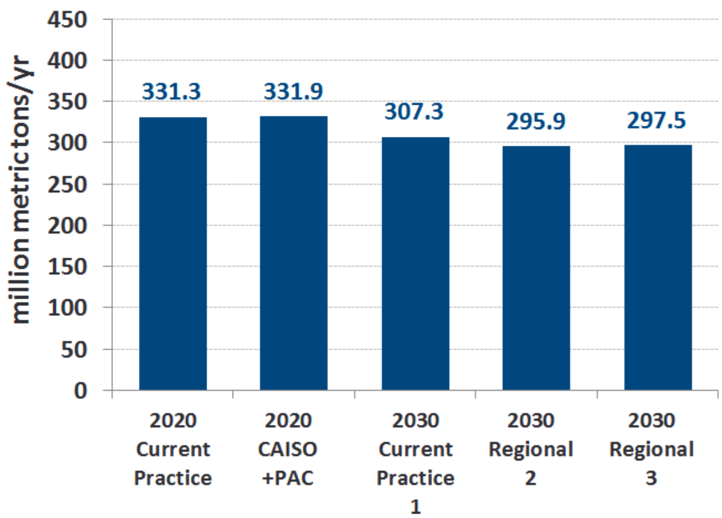
in simulated 2020 CO_2 emissions to be *de minimus*. Even if a portion of the simulated slight increase were realized in the near term, it would be very small compared to the much more significant long-term CO_2 emission reduction across the WECC, including the long-term emissions benefits of a regional market as shown in our 2030 simulations.

Figure 14: Simulated WECC-Wide Electric Sector CO_2 Emissions



As summarized in Figure 14 above, these simulations show that the CO_2 emissions from the electricity sector in 2030 decrease by 24-36 million metric tons from 2020 levels, despite the continued load growth assumed for the rest of WECC. The factors that drive these WECC-wide decreases between 2020 and 2030, include: (a) the addition of renewables to meet California's and western states' RPS; (b) coal plant retirements already considered in many utilities' resource plans (which are held constant across the current practice and regional market scenarios); (c) increase of California's CO_2 costs, reducing the competitiveness of resources that must pay for those CO_2 costs to import into California; and (d) GHG reduction policies in other parts of the WECC region (*e.g.*, Alberta's goal to retire all coal plants by 2030).

As also shown in Figure 14 above, the 2030 simulations show that an expanded regional market would additionally reduce WECC-wide CO_2 emissions by 10 to 11 million metric tons (~3.5% of total) compared to the Current Practice 1. This longer-term regional market benefit on WECC-wide emissions exceeds the small increase in our 2020 simulations by more than a factor of ten.

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cost to any California imports from coal plants (thus allowing all imports from coal generators to pay only the lower CO_2 cost associated with a gas combined-cycle plant).

d. Sensitivity Analyses of CO_2 Emissions

Our simulation results show that California's carbon regulations yield electricity sector CO_2 emissions levels that are well below the targets set by EPA's Clean Power Plan. This is not the case for the rest of the WECC, and our analyses of the baseline scenarios do not include any carbon constraints to address CPP compliance in the rest of the WECC. This is because: (a) the implementation of CPP has been stayed by the Supreme Court at the time of this study, and (b) specific state implementation plans have not yet been developed.

Nevertheless, in response to stakeholder feedback we conducted a sensitivity analysis that simulates how the U.S. WECC system would operate under a modest \$15/tonne CO_2 emissions cost in 2030 as a proxy for Clean Power Plan compliance. The results for this sensitivity shows that the modest \$15/metric ton CO_2 price would be more than sufficient to achieve CPP emission limits in the rest of the region as a whole. Based on these results, and given that the focus of this study is on California impacts, we have not conducted additional sensitivity analyses with even higher CO_2 prices. The detailed results for the 2030 sensitivity analyses of a \$15/ton CO_2 emissions price in the Rest of WECC are presented in Section C.2.e of Volume V.

Emissions were also evaluated for two other 2030 sensitivities: "Current Practice 1B" (which reflects higher baseline coordination in bilateral markets) and "Regional 3 without renewables beyond RPS." Under the higher-flexibility Current Practice 1B, 2030 emissions from California's in-state natural gas fleet increases CO_2 by 0.9% relative to the baseline Current Practice 1 scenario but decrease by 3.4% when accounting for the emissions impacts of imports and exports associated with serving California load. The 2030 WECC-wide CO_2 emissions in the Current Practice 1B sensitivity are 0.3% lower than in the Current Practice 1 baseline scenario.

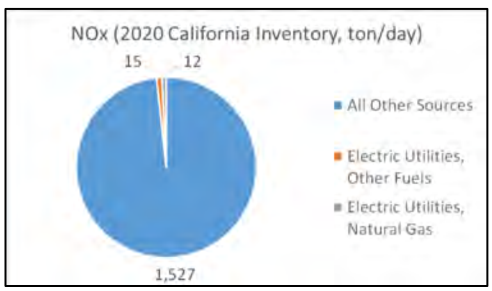
In a separate sensitivity analysis, Regional 3 without renewables beyond RPS results in a slight 0.6% increase in the dispatch of California's in-state natural gas–fired fleet compared to Current Practice 1. But this sensitivity would still avoid some of the excess startup emissions that would occur under the Current Practice 1. When considering imports and exports, the CO_2 emissions associated with serving California loads decline by 4.3% in this Regional 3 sensitivity (compared to Current Practice 1). The 2030 WECC-wide emissions for Regional 3 without renewables beyond RPS decrease by 0.4% relative to Current Practice 1. These sensitivity results are presented Volume V of this report.

e. NOx, SO_2 and PM2.5 Emissions Results

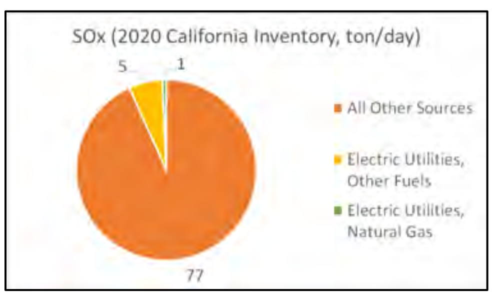
The analysis of NOx, SO_2, and PM2.5 emissions for 2030 shows that a Regional ISO-operated market would decrease these emissions from the electricity sector, both in California and in the rest of WECC. However, the results for 2020 showed a slight increase in these emissions for the rest of WECC due to the slight increase in coal dispatch discussed in the previous section. Nonetheless, to put these results in perspective, we note that California's electricity sector emits only a small percentage of the state's annual economy-wide inventory for NOx, SO_2, and PM2.5 pollutants. Transportation and area-wide (non-stationary) sources, and other industries, are the predominate emitters. Under any circumstances, a regional wholesale electricity market is likely to have a negligible impact on California's overall annual NOx, SO_2, and PM2.5 inventories. Figure 15 below shows the breakdown of electricity sector air emissions compared to the emissions from other sectors in California.

Figure 15: Baseline for NOx, SOx, and PM2.5 Emissions in California

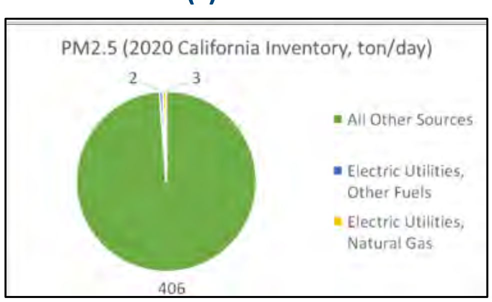
(a) NOx



(b) SOx



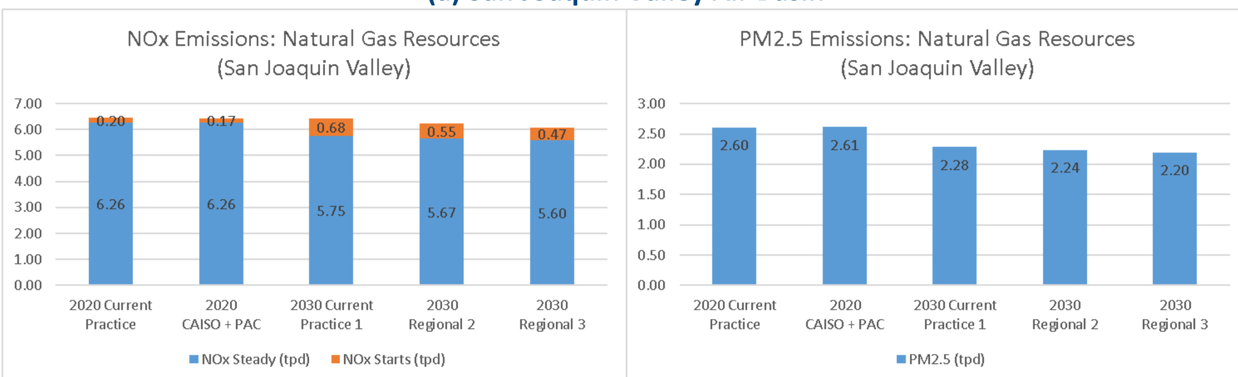
(c) PM2.5



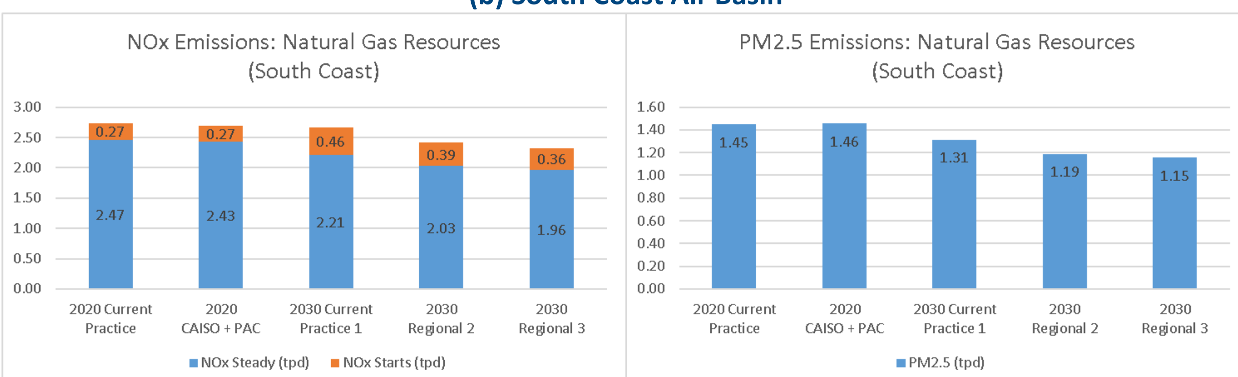
In California, a regional market is projected to reduce NOx and PM2.5 emissions in the persistent non-attainment areas of the San Joaquin Valley, South Coast, and Mojave Desert air basins. In addition, emissions in the Salton Sea air basin (which has relatively low emissions in any scenario) drop to nearly zero in the regional market scenarios. Figure 16 below shows the simulated results for NOx and PM2.5 air emissions in the most relevant air basins in California.

Figure 16: Simulated Electricity Sector NOx and $PM_{2.5}$ Emissions in California

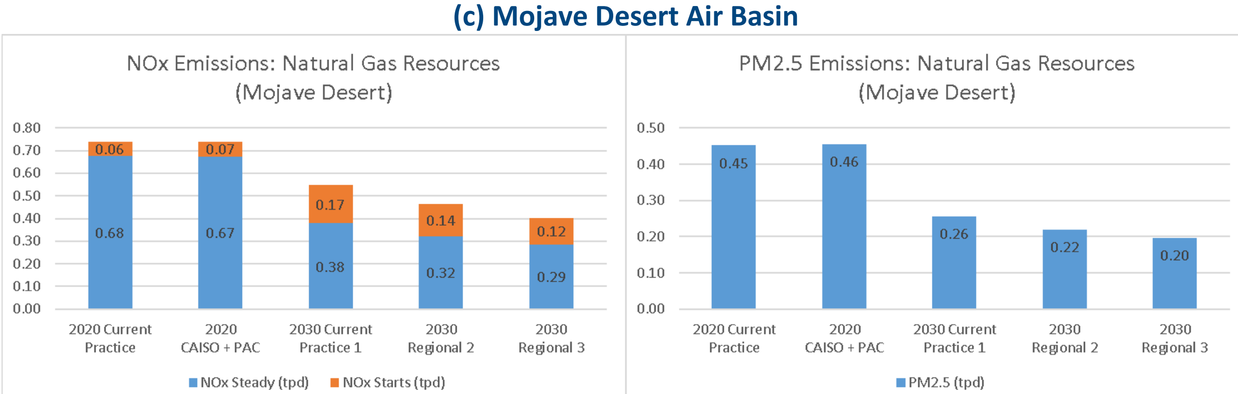
(a) San Joaquin Valley Air Basin



(b) South Coast Air Basin



(c) Mojave Desert Air Basin



The study also provides a separate presentation of average emissions rates from California's natural gas-fired resources over the three summer months for consideration of the effects on ozone levels. Managing ambient levels of ozone across California is a major focus of air quality management activity in many of California's air basins. Achieving reductions in NOx during the summer months is especially beneficial because NOx is a strong precursor to ground-level ozone. As explained in more detail in Volume IX of this report, the results show that the Regional 2 and Regional 3 scenarios achieve similar levels of NOx emissions reductions (-5.9%) in the summer season when compared with the 2030 Current Practice 1 scenario.

Emissions of NOx, SO_2, and PM2.5 were also evaluated for two 2030 sensitivities: Current Practice 1B (which reflects higher baseline coordination in bilateral markets) and Regional 3 without renewables beyond RPS. The emissions results for these sensitivities generally follow the fossil-fired generation results already described above in the context of CO_2 emissions. Under Current Practice 1B, NOx, SO_2, and PM2.5 emissions from California's in-state natural gas fleet are 1% to 2% higher than in the baseline Current Practice scenario.

Separately, Regional 3 without renewables beyond RPS results in a slight increase in the dispatch of California's natural gas–fired fleet and associated SOx and PM2.5 emissions compared to Current Practice 1, but this sensitivity still results in a net decrease of NOx emission in California by reducing the excess startups that would occur under the Current Practice 1.

3. Creation and Retention of Jobs and Other Benefits to the California Economy

Our analysis shows that impacts of an ISO-operated regional market on California jobs and the California economy are mostly driven by: (1) changes in investment in new electric supply resources; (2) changes in investment in other wholesale power infrastructure, such as high-voltage transmission; and (3) changes in customers' retail electricity rates that reflect the cost savings associated with supplying electricity to California. The first two drivers relate specifically to the differences in renewable generation investments across various scenarios, and the final driver stems from the ratepayer impact analysis previously presented in Section I.F.1. of this Volume. The job and economic impact analyses quantify some of the inherent tradeoffs between building new renewables resources in-state versus out-of-state, particularly when compared to the potential environmental impacts associated with the location of the renewable resources shown in the environmental analysis. More renewable generation development outside of California in Regional 3 (compared to the Current Practice 1) will lessen the environmental impacts within the state, but will reduce the number of direct jobs created through the construction and operations of those new resources in California. However, combined with the benefit of lower retail rates for electricity, due mostly to lower production costs and infrastructure investment costs, an expanded regional market will stimulate California's economy by increasing real incomes and thereby creating more jobs through consumer-expenditure-shifting towards industries with a higher job intensity.

a. State Economic Impacts

The economic analysis focuses on impacts on California's Gross State Product, real economic output, real income, and state tax revenue. The implementation of a regional market increases California's economic activities and improves these economic metrics. Although the estimated economic impacts are small relative to the magnitude of the entire California economy—Gross State Product, for example, increases by less than 1% with regional market—the impacts are high in absolute dollars terms. Gross State Product increases by between $1.2 billion to $1.7 billion and the state's real economic output increases by $2.3 billion to $2.7 billion annually if the regional market is implemented. Annual statewide real income increases by $4.1 billion to $7.9 billion, or about $290 to $550 per household on average per year. State tax revenues increase by $600 million to $1.6 billion in the regional market scenario compared to the Current Practice scenario. Figure 17 below illustrates the regional market impact on these California economic metrics.

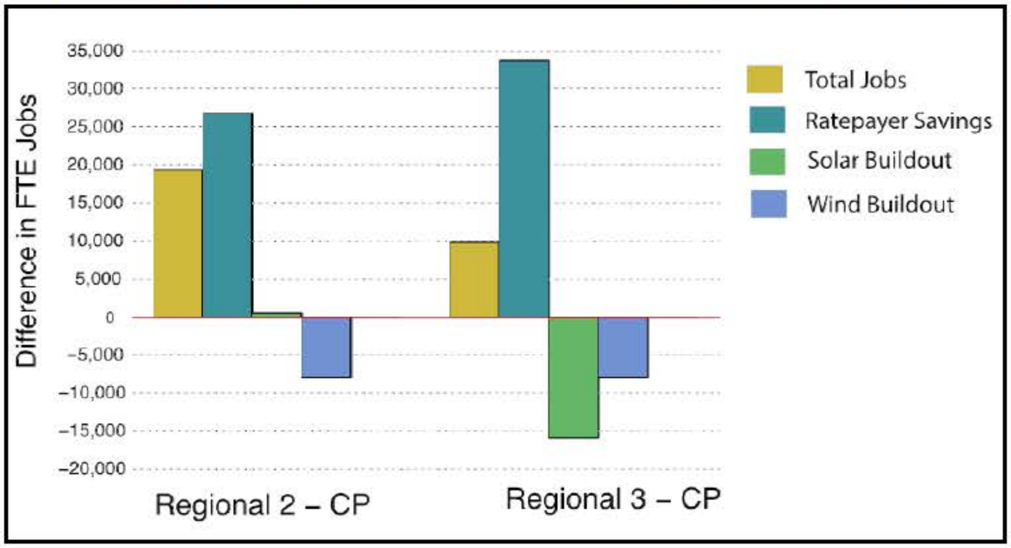
Figure 17: Overall Impacts on the California Economy
Change Relative to Current Practice 1 ($B)

	Regional 2 minus Current Practice 1	Regional 3 minus Current Practice 1
Gross State Product	$1.7	$1.2
Real Output	$2.7	$2.3
Employment (000)	19	10
Real Income	$4.1	$7.9
State Revenue	$0.6	$1.6

b. Impact on California Jobs

In 2030 Regional 2 scenario, the overall number of jobs in California increases by 19,300 by 2030, mostly due to an increase in jobs (+26,800) indirectly created by lower retail electricity rates, slightly offset by a decrease in jobs directly created from new resource development and operations (a decline of 7,400 jobs).[50] Similarly, in Regional 3, the overall jobs increase by 9,900 by 2030, due mostly to an increase in jobs indirectly created (+33,700 jobs), partially offset by a decrease in jobs directly created (a decline of 23,800 jobs). Figure 18 below shows the regional market's impact on jobs in California. These results are presented in more detail in Volume VIII.

Figure 18: Overall Regional ISO Market Impacts on California Jobs by 2030



4. Environmental Impacts in California and Elsewhere

In addition to the results related to air emissions, the environmental impact analysis of this study estimates the regional-market-related changes and locational shifts in land use for electricity resource infrastructure, land use of areas near or possibly within biologically-sensitive or environmentally-stressed areas, and changes in water use by existing operating generating units. Regional market impacts related to air pollutants and CO_2 emissions are summarized in Section I.F.2 above.

Within California, environmental impacts were analyzed by Competitive Renewable Energy Zones ("CREZs"), as defined by the California Public Utilities Commission for transmission planning to support the state's renewable energy resource development. The CREZs represent areas where renewable development is most attractive, due to resource potential, economic

50 Jobs estimates from the BEAR model measure total Full Time Equivalent (FTE) employment by occupation.

potential, and relatively low environmental impact. Figure 19 shows a graph of the CREZs analyzed in the environmental analysis.

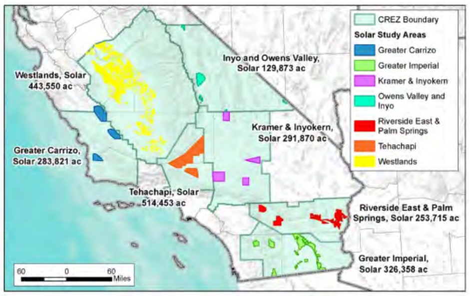
Figure 19: Resource Zones in California for Portfolios and Environmental Study

Outside of California, the environmental impacts were analyzed for certain selected development regions and on aggregate, for the rest of WECC as a whole. The environmental analysis contained in this SB 350 study is not site-specific and therefore it is not a siting study for any particular planned or conceptual renewable resource or transmission project.

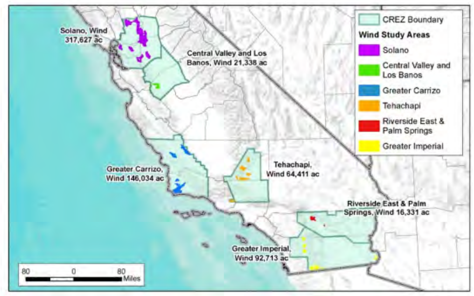
The environmental study starts with the renewable portfolios, which are drawn from coarsely-defined geographies inside California by the RESOLVE model based on estimates of location-specific resource development costs, resource development potential, and resource performance (*e.g.*, capacity factors). The RESOLVE model distributes resources to certain development areas outside of California, including the Southwest for solar resources, and the Northwest, Utah, Wyoming, and New Mexico for wind resources. Within each of these areas, the Aspen team "tailored" RESOLVE's resource locations to smaller study areas that reflect the efforts of similar previous studies and represent areas of opportunities for renewable development with the least environmental impact. This tailoring of study areas, as shown in Figure 20 below, allows Aspen to identify specific biologically-sensitive or environmentally-stressed locations that might realistically be impacted by the renewable portfolios and allows Aspen to better identify the scope of disadvantaged communities that might be affected, which is discussed further in the next section.

Figure 20: Tailored Study Areas for Environmental Study

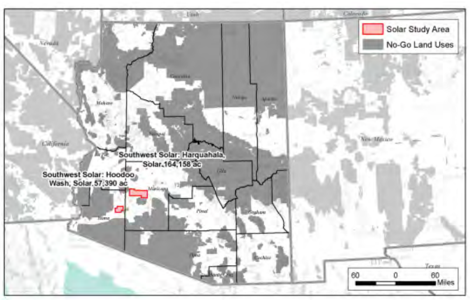
(a) California Solar



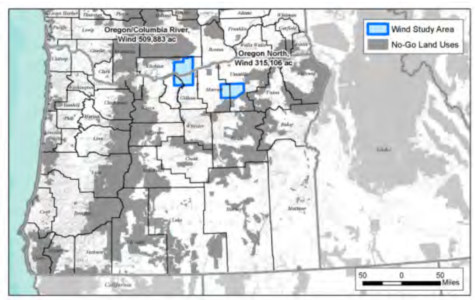
(b) California Wind



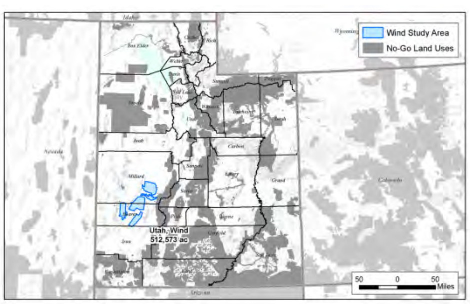
(c) Southwest Solar



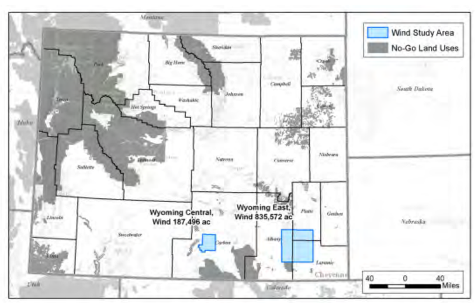
(d) Northwest Wind



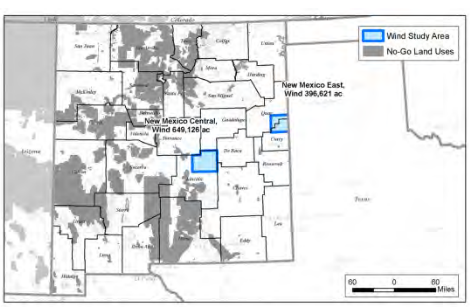
(e) Utah Wind



(f) Wyoming Wind



(g) New Mexico Wind



a. *Land Use Impacts*

Aspen analyzed the tailored renewable portfolio study areas for population density, agricultural uses, and coincidence with—or proximity to—protected lands, to find potential land-use incompatibilities. Although any conflicts in land use can be avoided or reduced on a case-by-case basis during the state or local siting process, a broader regional location for the renewable resource development reduces potential land-use incompatibilities. Within California, the renewable portfolios under Regional 2 and Regional 3 reflect a decreased wind buildout in California (compared to Current Practice 1), particularly in areas with medium or higher potential for land use incompatibilities, such as the Solano area. The renewable portfolio under Regional 3 reflects a decreased in-state solar buildout in areas with some potential for incompatibilities. Outside of California, less wind resource development is used for California's RPS in the Northwest in Regional 2, which decreases any potential for incompatibilities in that region. Although Regional 3 reflects a higher solar and wind buildout in the Southwest, Wyoming, and New Mexico, the buildout is in areas with relatively little potential for land use incompatibilities.

By enabling California to more efficiently build renewable resources to meet RPS, implementing a regional market significantly decreases the overall amount of land use measured in terms of acreages used.[51] Land use decreases in California by 42,600 acres in Regional 2 and by 73,100 acres in the Regional 3 scenario. Outside of California, land use decreases by 31,900 acres in Regional 2. Because larger sites are generally required for wind generation, land use increases by at least 69,300 acres in Regional 3, due to wind and additional land use associated with the necessary transmission rights-of-way to enable the renewable resource buildout to meet California's RPS. While the resource development footprint outside of California associated with expanded regional market and the associated emphasis on wind resources is larger, the actual ground disturbance would be much smaller; wind resources normally require only a portion of the acreage to be disturbed. Usually less than 10% of the acreage within a typical wind site may be disturbed, while the remainder of the land would remain undisturbed and available for other uses.

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51 One acre is about the size of a football field.

b. *Impacts on Biological Resources*

Aspen used the Western Governors' Crucial Habitat Assessment Tool ("CHAT") and a variety of other conservation planning and resource occurrence reports and studies,[52] to compile an inventory of biologically-sensitive and environmentally-stressed locations. Then, these locations were compared to the tailored renewable portfolio study areas to identify potential impacts on biological resources.

A regional market allows for lower impacts on biological resources overall compared to the Current Practice scenarios, but the difference in results for Regional 2 and Regional 3 illustrates the inherent tradeoff of building renewables in-state versus out-of-state to satisfy California's new 50% RPS mandate. For California, a regional market reduces the number of habitats impacted by new solar resources from seven to five, the number of areas sensitive to avian and bat mortality associated with new wind resources from six to four, and the potential for wildlife movement constriction, particularly in the Riverside East and Palm Springs areas. Outside of California, particularly in Regional 3 with more of an out-of-state renewables development focus, the potential for avian and bat mortality from new wind resource developments increases in Wyoming and New Mexico.

c. *Water Use Impacts*

California does not have groundwater regulations that limit the amount of groundwater extracted by wells and pumps, but groundwater use is nonetheless a significant issue for the state. Groundwater extraction and the drought of recent years have resulted in historically low groundwater elevations in many regions of California. To address impacts on water use during construction, Aspen compared the tailored renewable portfolio study areas to the California Department of Water Resources' Critically Overdrafted Groundwater Basins.[53] Areas of particular focus in the analysis include Greater Imperial, Riverside East and Palm Springs, Tehachapi, and Westlands. Outside of California, Aspen reviewed data from the World Resources Institute to assess relatively high-risk areas for groundwater use issues. The analysis

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52 Western Association of Fish and Wildlife Agencies. 2016. *West-wide Crucial Habitat Assessment Tool (CHAT) Data*. Available at: http://www.wafwachat.org/data/download .

53 California Department of Water Resources; available at: http://www.water.ca.gov/groundwater/sgm/cod.cfm

focuses on new solar resources in Arizona and new wind resources in Utah, Wyoming, and New Mexico as they are typically partially or entirely located in the identified high-risk areas.

Within California, the renewable portfolio under Regional 2 slightly decreases water use (compared to Current Practice 1) for construction in high-risk areas, and in Regional 3, the renewable portfolio further decreases the amount of in-state water used for construction in high-risk areas and in other areas of lower risk.

Aspen analyzed impacts on water consumption during operations for existing generating units within California and in the rest of WECC, using estimates for water consumption by technology type from the National Renewable Energy Laboratory.[54] Limited regionalization in 2020 would reduce the water use in California by facilitating a reduction in water used for electricity generation by 1.5%. In 2030, the regional market would reduce the water used for electricity generation in California by at least 4%, and would also modestly reduce the water used for electricity generation outside California.

5. Impacts in California's Disadvantaged Communities

The analyses of economic impacts, job impacts, and environmental impacts in California and elsewhere include a more detailed examination of possible impacts on California's disadvantaged communities to respond to the legislative requirements under SB 350.

Disadvantaged communities in California are defined by the California Communities Environmental Health Screening Tool ("CalEnviroScreen 2.0"). This tool evaluates and ranks census tracts on 19 indicators for pollution burden and sensitive population and socioeconomic characteristics. The figure below shows the CalEnviroScreen 2.0 combined ranking for all 19 indicators. Higher scores indicate relatively higher pollution burdens and more sensitive populations within those communities. Disadvantaged communities are defined as the census tracts that are in the top 25th percentile for greatest pollution burden and the lowest socioeconomic conditions. Figure 21 below shows the census tracts with their relative scores on the screening tool. The figure shows the disadvantaged communities in orange and red colors,

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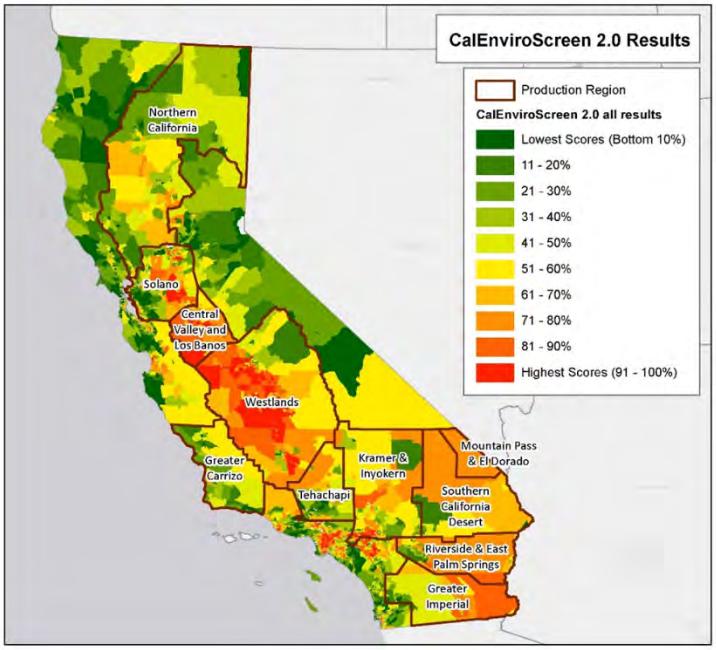
54 NREL (2011). A review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies. Available at: http://www.nrel.gov/docs/fy11osti/50900.pdf.

with most of the disadvantaged communities and populations concentrated in the Los Angeles, Central Valley, and Inland Valley areas.

Figure 21: CalEnviroScreen 2.0 Combined Pollution Burden and Sensitive Population Scores

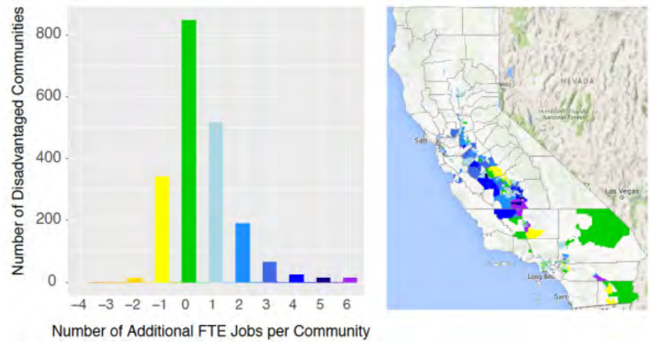


As part of the California economic and job impact analysis, the results are mapped to the CalEnviroScreen 2.0 scores at the census tract level. That way, one can distinguish results for disadvantaged and other communities.

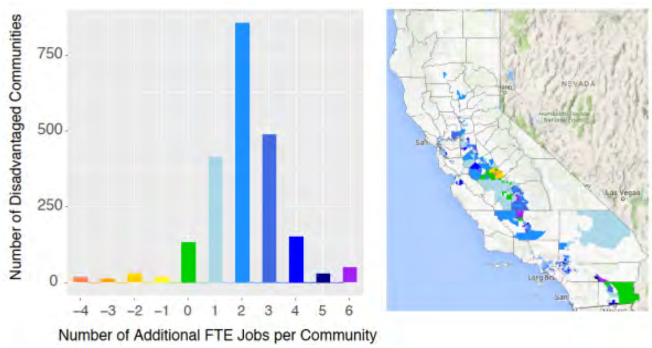
From a job and economic impact perspective, a regional market creates more jobs and more income in many disadvantaged communities, as shown in Figure 21. Real income increases by about $180 to $340 per year, and net jobs increase by 800 to 2,800 between 2020 and 2030. Because the disadvantaged communities are low-income communities, the job and income increases disproportionately create more value for disadvantaged communities than in other higher-income communities. Figure 22 below summarizes the results for job and economic impacts on disadvantaged communities. More detail on these results, including results specific to the Los Angeles, Central Valley, and Inland Valley areas, can be found in Volume X.

Figure 22: Job and Economic Impacts on California's Disadvantaged Communities Regional 3 and Regional 2 Impacts, Relative to Current Practice 1

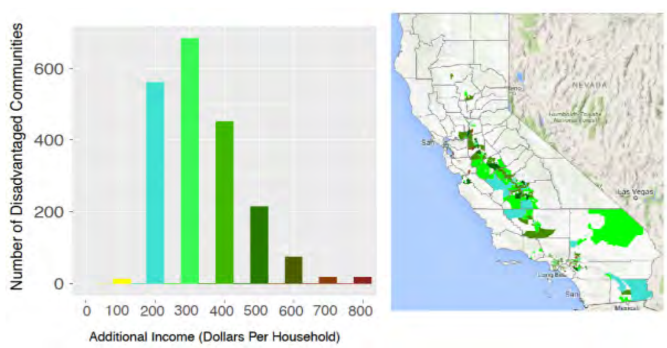
Employment Impacts: Regional 3 Minus Current Practice 1



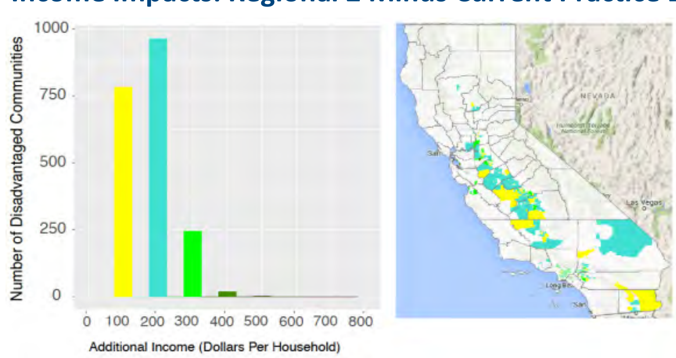
Employment Impacts: Regional 2 Minus Current Practice 1



Income Impacts: Regional 3 Minus Current Practice 1



Income Impacts: Regional 2 Minus Current Practice 1



As part of the environmental analysis of disadvantaged communities, we compare our results to the CalEnviroScreen 2.0 scores for each tailored study area, air basin, and CREZ for the new renewables needed to meet California's 50% RPS. This allows us to determine the number of disadvantaged communities in proximity to and potentially affected by new resource development and air emissions from existing fossil-fired generating units.

The study results show that a regional market decreases community-scale construction-related environmental impacts by decreasing renewable resource development in California, particularly in the Westlands area where a significant amount of new solar development is avoided because the additional solar generation is no longer needed to replace curtailed renewable resources in California under the expanded regional ISO market in 2030. The regional market reduces the use of natural-gas generators in California, which in turn reduces the amount of water used during power production and decreases power plant emissions in the San Joaquin Valley and South Coast air basins. More detail on these results, including results specific to the Westlands, San Joaquin Valley, and South Coast areas, can be found in Volume X.

6. Reliability and Integration of Renewable Energy Resources

Regional market operations and planning will allow for more cost effective and reliable integration and balancing of intermittent renewable resources.[55] Some of these benefits of increased renewable integration and reliability associated with closer regional coordination across the many existing Balancing Areas in the WECC has been documented and recognized in the context of the EIM.

A full "Day 2" regional market will magnify these EIM-related benefits by adding to the coordination benefits achieved through regional market operations, which consist of: (1) a day-ahead energy market; (2) day-ahead and intra-day system-wide forecasting of intermittent renewable generation levels; (3) optimal economic and reliability-based commitment of conventional generating units; and (4) region-wide, co-optimized markets for regulation reserves, operating reserves, and flexible capacity for load-following reserves. In addition to these operational benefits, a regional ISO-based market will benefit from reduced generation capacity needs due to load diversity benefits of the larger footprint. It will also benefit from the

[55] See Volume XI and the discussion of existing studies in Volume XII.

integrated, region-wide operational, reliability, and transmission planning functions performed by the larger ISO with its stakeholders.

Covered in other parts of the analysis, key aspects of reliability and renewable integration benefits of a larger ISO-operated regional market already have been quantified in: (1) the load diversity analysis, which assesses how resource adequacy requirements can be met with less generating capacity (Volume VI); (2) the nodal market simulations, which simulate more optimized power flows on the transmission grid, reduced curtailments, and reduced need for ramping, load-following, and operating reserves at high levels of renewable resource development (Volume V); and (3) the renewable investment optimization, which recognizes integration benefits when selecting the renewable portfolios that can meet California's 50% RPS (Volume IV).

However, the estimation of the benefits associated with reliability and renewable integration benefits captured in California ratepayer savings does not reflect other values of achieving more reliable region-wide system operations. For example, expanding ISO operations to a larger regional footprint will offer significant reliability benefits to both California and the larger regional market area. Regional ISO operations and practices will offer various reliability benefits over the standard operational practices of Balancing Authorities in the WECC footprint. Because the WECC is a single interconnected power system, reliability events in neighboring WECC areas affect California as well.[56] Expanding CAISO operational practices consequently offer reliability benefits to (a) the expanded regional footprint that, in turn, (b) increases reliability in the ISO's current California footprint. Reliability-related benefits will be particularly pronounced during stressed system conditions, such as extreme weather, drought, and unexpected outages.

As discussed in Volume XI, an ISO-operated, consolidated regional market and balancing area offers important additional **reliability benefits** beyond the enhanced reliability benefits achieved by EIM. These enhanced regional reliability-related benefits include:

- Improved real-time awareness of system conditions;

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[56] Examples of WECC-wide reliability events that affected California include the October 6, 2014 Northwest RAS Event; the September 8, 2011 Arizona–Southern California Outage; and the August 10, 1996 Western Interconnection (WSCC) System Disturbance.

- More timely, more efficient, and lower-cost congestion management and adjustments for unscheduled flows;
- Regionally-optimized, multi-stage unit commitment;
- Enhanced systems and software for monitoring system stability and security;
- Enhanced system backup;
- Coordinated operator training that exceeds NERC requirements, more frequent review of operator performance and procedures, and consolidated standards development and NERC standards compliance;
- More unified regional transmission planning to address long-term reliability challenges;
- Broader fuel diversity to more effectively respond to reliability challenges associated with changes in fuel availability or costs and hydro/wind/solar conditions; and
- Better price signals for investment in new resources of the right type and in the right geographic locations
- More effective deployment and dispatch of resources and reserves that will enhance reliability and recognizes system conditions across the entire regional foot print.

A larger regional ISO-operated wholesale power market will improve the **integration and balancing of renewable resources**,[57] thereby facilitating the development of lower-cost renewable resources through:

- A single regional energy market for selling the intermittent output of renewable resources
- Coordinated and centralized forecasting of renewable output to reduce balancing costs and curtailments;
- Market-based ancillary services and reduced reserves and load-following requirements in a larger, more diversified region;

57 For example, SPP has recently announced that within its larger, consolidated balancing area it can now manage wind generation of up to 60% of its load. As noted by SPP's CEO, due to the larger footprint, SPP can "forecast the wind rise and decline such that we can bring other resources to bear against the variability of wind…[y]ou just couldn't have done that when we were operating as 20-plus different balancing authorities." (Source: Gavin Blade, "SPP CEO: Regionalization, transmission help push renewables penetration near 50%," UtilityDive, May 26, 2016.)

- Uniform region-wide generation interconnection and transmission planning processes;
- Improved regional transmission planning to provide access to low-cost renewable areas within the regional footprint;
- Easier contracting of renewable power supplies for load-serving entities and commercial and industrial customers; and
- Improved financial hedging options and access to more liquid trading hubs.

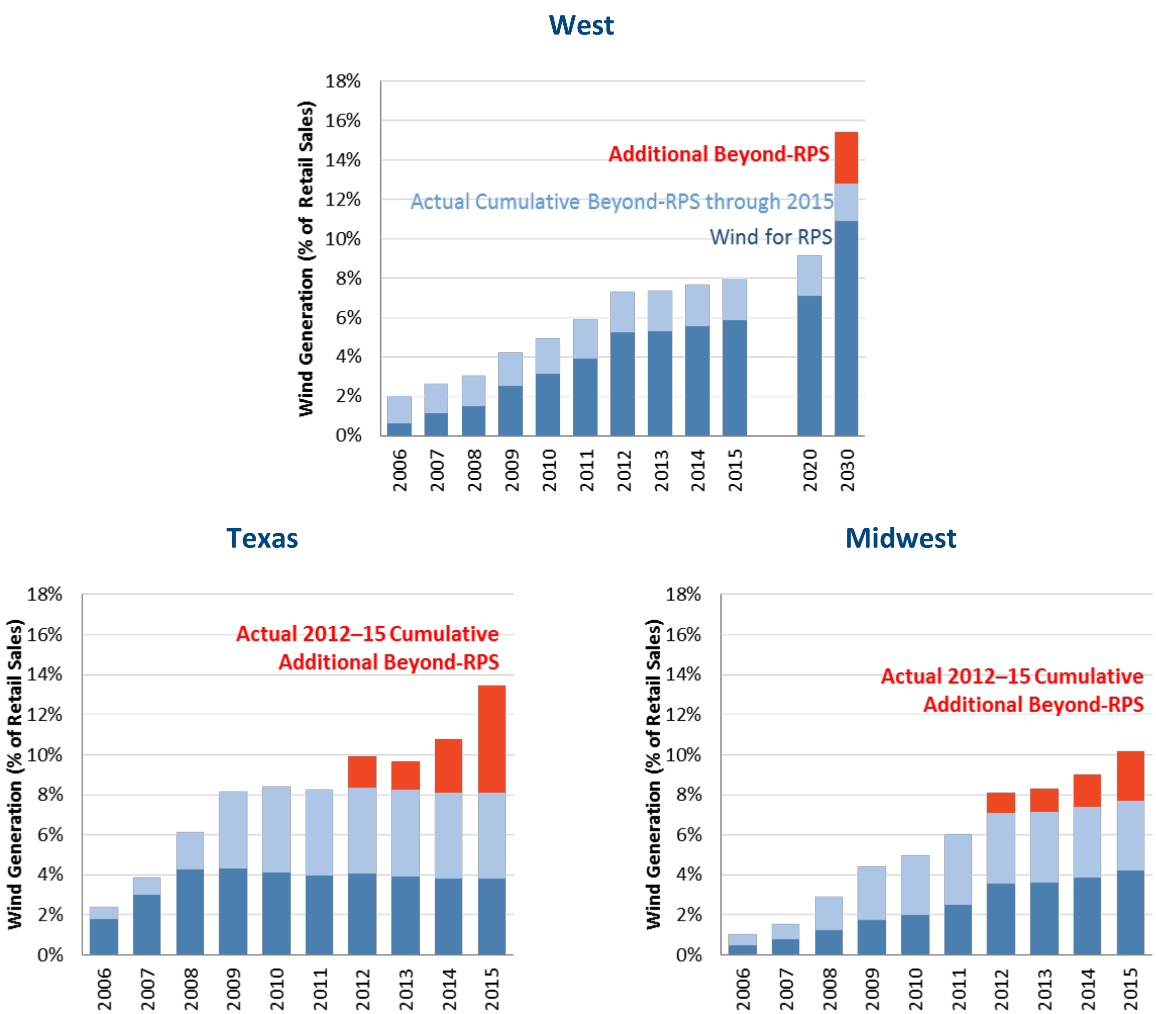
The reduction of integration and balancing costs faced by renewable resources facilitates a more rapid development and growth of renewable generation in the regional footprint, including accelerated renewable development beyond the western states' RPS requirements.

As shown in Figure 23, the regional markets in the Midwest and Texas (operated by MISO, SPP and ERCOT) have shown significant growth of renewable resources, particularly resources developed beyond RPS requirement. As discussed in more detail in Volume XI, these beyond-RPS renewables developments are supported by voluntary purchases signed by load serving entities and commercial and industrial customers. They have occurred almost exclusively in regions that offer both (1) access to low-cost renewable resources that make voluntary purchases economically attractive, and (2) ISO-operated regions that provide a ready market for integrating, compensating, and balancing the intermittent energy produced by the renewable resources.

As discussed further in Volume XI, a total of 7,700 MW of "beyond-RPS" wind generation (equivalent to 6.9% of retail load) have been developed only over the last five years in Texas and a total of 9,200 MW of beyond-RPS wind generation (equivalent to more than 3% of retail load) have been developed over the last five years in the Midwest. Figure 23 below shows that much less growth in voluntary wind generation development beyond-RPS mandates has occurred in the WECC region, which contains areas with similarly low-cost wind resources but does not currently offer access to ISO-operated wholesale power markets in those low-cost areas.

Recognizing these trends of renewable generation developments beyond RPS requirements in other ISO-operated regional markets with access to low-cost renewable resources, our SB 350 study assumes that similar developments would occur in the regional market scenario by 2030. Specifically, the market simulations assume that in the regional market scenarios (Regional 2 and Regional 3), an additional 5,000 MW of beyond-RPS wind generation would be facilitated by the regional market incrementally between 2020 and 2030 in the low-cost wind generation regions of Wyoming and New Mexico. As shown in Figure 23, this would be equivalent to 2.6% of the regional market's projected 2030 retail load—a level below those achieved in SPP, MISO, and ERCOT over the last five years. Because the regional market in the West would offer access to the country's lowest-cost solar generation resources, adding only wind generation as the beyond-RPS resource facilitated in the regional market scenarios is a conservatively low assumption. In reality, a significant amount of solar resources beyond those needed to meet RPS will be developed across the West. This trend in solar generation development is already evident in Texas.

Figure 23: Wind Generation Development to Meet RPS and Beyond



Notes and Sources: Historical RPS and beyond-RPS wind installations data and retail load data provided by Dr. Galen Barbose of LBNL. Average 2012 wind capacity factors by region used to estimate wind generation based on installed capacity. Assumed a 10% overall loss factor when comparing wind generation and retail load.

7. Survey of Existing Studies and Other Potential Impacts

We reviewed a large number of existing studies to inform and benchmark our analysis of a regional market. Many of the studies we reviewed estimate the benefits of moving to organized and centralized wholesale electricity markets and operations. Various "Day-2" market studies evaluate the benefits of expanding from a de-pancaked transmission scheduling and energy imbalance markets to centralized Day-2, or day-ahead, markets. Several older RTO studies estimate the benefits and costs to an RTO, following the issuance of FERC's 1999 landmark Order No. 2000, which required transmission owners to consider and evaluate RTO formation and membership. More recent RTO participation studies evaluate the benefits and costs to a load-serving entity of joining an existing RTO. Energy imbalance market studies evaluate the benefits of the Western EIM, or the benefits of a utility joining the EIM. We also reviewed European market integration studies, which estimate the benefits of market integration in the European context.

Other studies we reviewed focus on renewable resource development and integration into system operations and markets. The renewable integration studies we reviewed discuss various challenges of integrating higher penetrations of renewable resources. We reviewed studies that analyze the role of markets in enabling renewables development beyond RPS mandates. Volume XII includes additional detail and a bibliography of all of the studies we reviewed.

As discussed above, we find that most prospective studies estimated that regional market integration would reduce production costs by 1%–3%. Most of these prospective studies acknowledged the limitations associated with the analyses, because many of the benefits of participating in a regional market are difficult to capture in simulation-based analyses. Given the limitations of using simulation models to conduct prospective analyses, several system operators analyzed the values provided by regional markets with a retrospective approach. The retrospective studies find higher production cost savings than the prospective analyses, in the 2%–8% range. These savings reflect a relatively large step from a "no market" status quo (*i.e.*, only bilateral trading among individual balancing areas with pancaked transmission charges as in the non-CAISO portion of the WECC) to a full regional Day-2 marketplace with consolidated balancing areas, de-pancaked transmission, nodal day-ahead and real-time energy markets, and ancillary services markets. Estimated savings are smaller for more modest steps towards centralized markets. For example, studies analyzing the benefits of moving from a region with fully de-pancaked transmission charges and real-time imbalance markets to a Day-2 market design with consolidated balancing areas and nodal energy markets offer incremental benefits of

3–5%. This latter group of studies is most comparable to our SB 350 study results, which estimate an approximately 5% in WECC-wide production cost savings from de-pancaked transmission rates and centralized day-ahead markets and operations. Finally, studies analyzing the CAISO's and ERCOT's previous move from a zonal Day-2 market design to a nodal Day-2 market design estimated incremental benefits of approximately 2% of total production costs or wholesale power prices.

The studies we reviewed consider a wide variety of benefits other than production cost savings. Expanded geographic coverage of regional markets allows taking advantage of greater load diversity, which reduces the total generating capacity needed to meet resource adequacy standards. Regional markets make it easier to reach low-cost renewable resources and reduce the burden of integrating intermittent renewable resources, thus creating significant additional cost savings. Based on the reviewed studies, the combination of these load diversity and renewable access and integration cost savings would likely be the equivalent of a 2–6% additional reduction in production costs even under today's level of renewable energy development. These additional benefits would be available to both California and market participants in the rest of the WECC.

Figure 24 below shows a summary of market integration benefits based on our literature review. All savings in the figure are reported as the equivalent to a percentage of total production costs. As the figure shows, the production cost savings captured by prospective production cost simulations are likely understated and represent only a portion of the overall benefits of market integration. The overall savings shown in the last row of the figure includes additional production cost benefits not captured by prospective studies, investment cost savings, and additional benefits under high renewables scenarios. Based on the results of this review of existing market integration studies, the total benefits of a regional market (including investment-related benefits) range from 6% to 13% of total production costs. Considering the additional benefits related to the much higher 50% share of renewable generation that will have to be achieved for serving California electricity loads, the benefit of expanding the CAISO into a larger regional market in the WECC, and beyond an energy imbalance market, must be expected to exceed the range of the regional market benefits achieved to date as documented in existing studies.

Benefits not quantified in this SB 350 study include the value of increased reliability, the competitive benefits of a larger regional market, improved scheduling and dispatch within existing balancing areas, improved renewable generation forecasting, improved regional transmission planning, facilitation of additional renewable generation development, improved accommodation of the early retirement of existing plants, avoiding or deferring the construction of new fossil-fueled plants through better utilization of the regional generation fleet, and improved utilization of the load-following capabilities of the region's hydroelectric generating plants.

Figure 24: Overall Magnitude of Market Integration Savings Based on the Review of Other Studies (All Savings Reported as Percentage of Total Production Costs)

Type of Benefit		Estimated Savings as % of Total Production Costs
Savings Captured by Real-Time Energy Imbalance Markets (similar to EIM)	[1]	0.1% – 1%
Other Production Cost Savings Estimated by Prospective Studies	[2]	0.9% – 2%
Total Production Cost Savings Estimated by Prospective Studies	**[3]**	**1% – 3%**
Plant Efficiency and Availability Improvement	[4]	2% – 3%
Additional Real-Time Savings (Considering Daily Uncertainties)	[5]	1% – 2%
Additional Operational Savings with High Renewables	[6]	0.1% – 1%
Total Additional Production Cost Savings Estimated by Some Studies	**[7]**	**3.1% – 6%**
Load Diversity Benefits (Generation Investment Cost Savings)	[8]	1% – 1.4%
Renewable Capacity Cost Savings	[9]	1% – 4%
Total Investment Cost Savings (Expressed as Equivalent to % of Production Costs)	**[10]**	**2% – 5.4%**
Total Overall Savings as Share of Total Production Costs	**[11]**	**6% – 13%**

Sources and Notes:

[1]: Range from E3's utility-specific and WECC-wide EIM studies

[2] = [3] – [1] Includes benefits of Transmission Charge De-Pancaking and Day Ahead Markets in all studies, Ancillary Service Markets in some studies, and Full Real Time Benefits and Improved Transmission utilization in some studies

[3]: Based on summary table for prospective studies (see 0)

[4]: Based on results in Chan, H.S. *et al.*, "Efficiency and Environmental Impacts of Electricity Restructuring on Coal-fired Power Plants," August 2012

[5]: Difference between savings in retrospective studies and sum of savings in prospective studies and efficiency and availability savings

[6]: Low end of range based on "Overgeneration Management" savings in the PAC Integration study. High end based on savings of "Enhanced Flexibility" in high renewables scenario in NREL Low Carbon Grid study.

[7] = [4] + [5] + [6]

[8]: Low end of range based on the PAC Integration study. High end based on average of savings from the PAC Integration, National RTO, and Entergy/SPP MISO studies.

[9]: Based on reduced resource cost estimated in PAC Integration study.

[10] = [8] + [9]

[11] = [3] + [7] + [10]

List of Acronyms

AAEE	Additional Achievable Energy Efficiency (CEC EE projection)
AB32	California Assembly Bill 32 (regulates GHGs)
ATC	Available Transmission Capacity
AWEA	American Wind Energy Association and Interwest Energy Alliance
BAMx	Bay Area Municipal Transmission Group
BPA	Bonneville Power Administration
Brattle	The Brattle Group
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
Calpine	Calpine Corporation
CARB	California Air Resources Board
CBE	Communities for a Better Environment
CDWR	California Department of Water Resources
CEC	California Energy Commission (state regulator)
CED	California Energy Demand forecast (CEC, biennial study)
CEII	Critical Energy Infrastructure Information
CESA	California Energy Storage Alliance
CfD	Contracts for Differences
CLECA	California Large Energy Consumers Association
CMUA	California Municipal Utilities Association
CPP	Clean Power Plan (EPA)
CPUC	California Public Utilities Commission (state regulator)
CREZ	California Renewable Energy Zones
CRR	Congestion Revenue Rights
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act (federal)
DOE	U.S. Department of Energy
DR	Demand Response
Defenders	Defenders of Wildlife
Diamond	Diamond Generating Corporation
E3	Energy and Environmental Economics
EAP	Energy Action Plan (CEC & CPUC, 3 reports)

EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
EPSA	Electrical Power Supply Association
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas (primarily carbon or carbon dioxide)
GMC	Grid Management Charges
GRE	Great River Energy
GWSA	California Global Warming Solutions Act of 2006 (AB32)
Greenling/APEN	The Greenlining Institute and Asian Pacific Environmental Network
Gridview	Simulation tool for system planning analyses
ICNU	The Industrial Customers of Northwest Utilities
IID	Imperial Irrigation District
IEPR	Integrated Energy Policy Report (CEC, biennial report)
IOU	Investor-Owned Utility (3 electric IOUs in California: SCE, SDG&E, and PG&E)
IRP	Integration Resource Plan
ISO	Independent System Operator
LADWP	Los Angeles Department of Water & Power
LBNL	Lawrence Berkeley National Laboratory
LCGS	Low Carbon Gris Study
LSA	Large-Scale Solar Association
LS Power	LS Power Development, LLC
LTPP	Long-Term Procurement Plan (under CPUC docket, biennial cycles)
MID	Modesto Irrigation District
MISO	Midcontinent Independent System Operator
MMTCO2e	Million Metric Tonnes of CO_2 Equivalent
MW	Megawatt (one million watts)
MWh	Megawatt-hour
MegaWatt Storage	MegaWatt Storage Farms, Inc.
NCI	Navigant Consulting Inc.
NCPA	Northern California Power Agency
NEC	Northwest Energy Coalition
NERC	North American Electric Reliability Corporation

NRDC	Natural Resources Defense Council (Western Grid Group, Western Resource Advocates, Utah Clean Energy, Northwest Energy Coalition, Islands Energy Coalition and Vote Solar)
NREL	National Renewable Energy Laboratory
NRG	NRG Energy, Inc.
NYISO	New York Independent System Operator
ORA	The Office of Ratepayer Advocates
OTC	Once-Through Cooling
PacifiCorp	PacifiCorp
PMA	Power Marketing Agency
PPA	Power Purchase Agreement
POU	Publicly-Owned Utility
PPC	Public Power Council
PTO	Participating Transmission Owner
Peak Reliability	Peak Reliability
PG&E	Pacific Gas and Electric (1 of 3 IOUs in California)
PGP	Public Generating Pool
Powerex	Powerex Corp.
PPC	Public Power Council
RAR	Resource Adequacy Requirement
REBA	Renewable Energy Buyers Alliance (REBA)
REC	Renewable Energy Credit
RESOLVE	Renewable Energy Solutions
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SB-350	Clean Energy and Pollution Reduction Act of 2015
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCL	Seattle City Light
SDG&E	San Diego Gas and Electric (1 of 3 IOUs in California)
SONGS	San Onofre Nuclear Generating Station
SPP	Southwest Power Pool
Sierra Club	Sierra Club
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California

Stone Hill	Stone Hill CP, LLC
SVP	Silicon Valley Power
SWPG	SouthWestern Power Group
TANC	Transmission Agency of Northern California
TEAM	Transmission Economic Assessment Methodology
TEPPC	Transmission Expansion Planning Policy Committee (part of WECC)
TOR	Transmission Ownership Rights
TPP	Transmission Planning Process (CAISO, annual report)
TransCanyon	TransCanyon, LLC
TransWest	TransWest Express LLC
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists on behalf of the Environmental Defense Fund ("EDF") and the Center for Energy Efficiency and Renewable Technologies ("CEERT")
USF	Unscheduled flow
WAPA	Western Area Power Administration
WCEA	Western Clean Energy Advocates
WECC	Western Electricity Coordinating Council
WGA	Western Governors Association
WGG	Western Grid Group
WRA	Western Resources Advocates
WREZ	Western Energy Renewable Zones
WSP	Westlands Solar Park

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Senate Bill 350 Study

Volume II: The Stakeholder Process

PREPARED FOR

California ISO

PREPARED BY

The Brattle Group

Energy+Environmental Economics

BEAR

Aspen Environmental Group

July 8, 2016

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

Volume II: Table of Contents

Volume II. The Stakeholder Process

A. Introduction

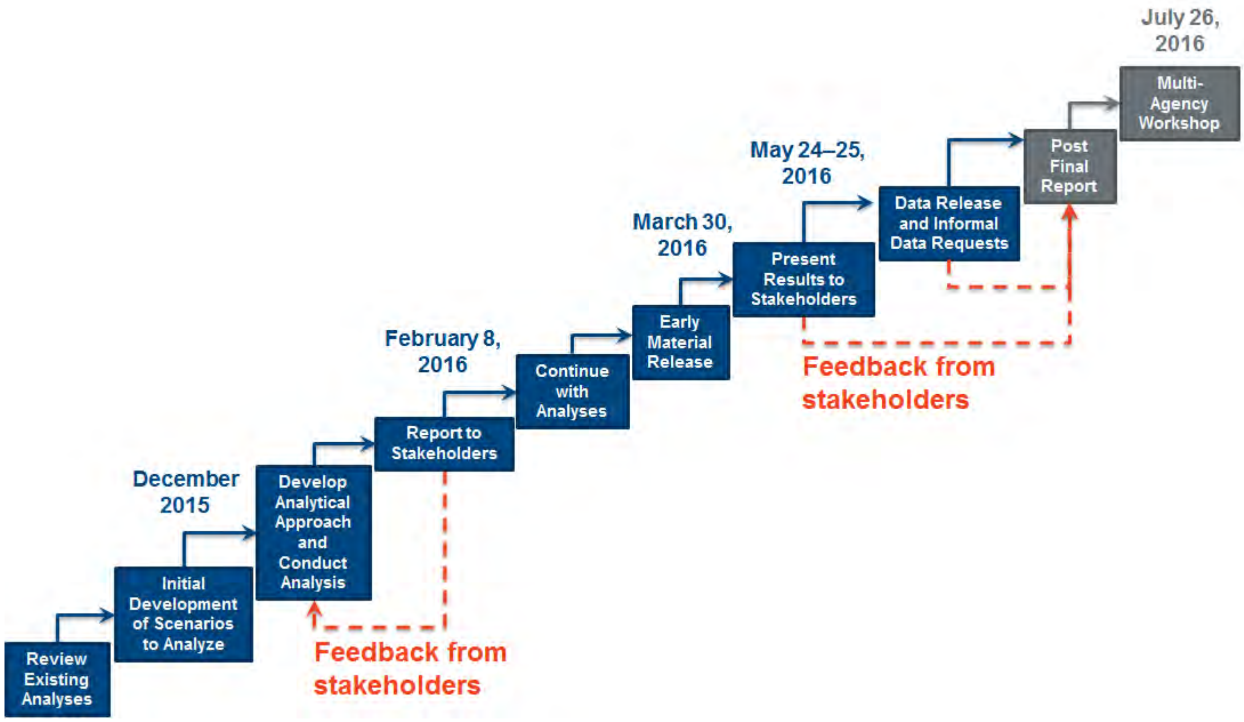
The SB 350 study efforts include a stakeholder process, by which the study team provides study assumptions, methodology, results, and detailed descriptions of all of the relevant metrics used in the analyses. The stakeholder process began with the study team presenting initial ideas about the approach and assumptions to be used in the analyses, modifying the approach based on stakeholder comments, continued through providing stakeholders interim updates associated with the approach and study assumptions, followed by providing detailed data and explanations of the preliminary results. This stakeholder process involved formal stakeholder workshops and comment periods, supplemental webinars, data releases and review of study data by stakeholders, and written correspondences that responded to specific stakeholder questions. All workshops and webinars were recorded as a service to stakeholders who couldn't join, or would like to review the proceedings.

In response to stakeholder comments the study team made several modifications to the SB 350 study's approach and methodology. We made adjustments to the scope of regionalization impacts to analyze, the footprint of regionalization to consider, the definition of the study's scenarios, sensitivities to consider, and a number of other specific inputs and assumptions to our analytical models.

B. Timeline of Stakeholder Feedback

The study team formally solicited feedback from stakeholders following two stakeholder workshops. After the first stakeholder workshop, we also responded to informal stakeholder questions, comments and requests through customized written responses to each comment received, early release material, supplemental webinars, data release and a number of webinars to walk-through the details of the analysis. Figure 1 shows the overall study timeline, from December 2015 through July 2016, and key times of stakeholder feedback.

Figure 1: SB 350 Study Timeline



Specifically, the stakeholder process consisted of:

- **February 8, 2016** stakeholder meeting to discuss proposed study framework, methodology, and assumptions. Stakeholders submitted to the ISO their comments and feedback, which the study team used to refine the study approach, study assumptions, and the scenarios and sensitivities analyzed.
- **March 18, 2016** the study team responded to stakeholder comments from the February 8 stakeholder meeting.
- **March 30, 2016** additional detail on study assumptions and methodologies ("early release material") were posted on the CAISO website in response to stakeholder requests.
- **April 14, 2016** the study team hosted a webinar to discuss the early release materials with stakeholders.
- **May 24–25, 2016** stakeholder meeting to discuss preliminary study results; stakeholder comments were due by June 22, 2016.
- **June 3 and 10, 2016** detailed analytical inputs, assumptions, calculations, and results were released for stakeholder review. Supplemental material, in response to ongoing stakeholder requests, was released on June 14, 17, 21, and 22, 2016 and on July 5, 2016.
- **June 21, 2016** the study team hosted a webinar to discuss the details of the ratepayer impact analysis, including TEAM methodology.
- **July 1, 2016** the study team provided initial responses to stakeholder comments from the May 24–25 stakeholder meeting.

Finally, SB 350 requires the ISO to hold at least one public workshop jointly with the California Public Utilities Commission, the California Energy Commission, and the California State Air Resource Board ("Joint Agency Workshop") to discuss the results of the study. The workshop is scheduled to be held in July 26, 2016 at the Secretary of State, Auditorium at 1500 11th Street, First Floor, Sacramento, CA 95814 (enter at 11th and O Streets).

C. Modifications to the Study in Response to Stakeholder Feedback

The study team made several refinements to the study approach and methodology in response to stakeholder feedback. Specific changes include:

- Refined renewable portfolio optimization:
  - Added a scenario (Regional 3) to reflect more of an out-of-state focus on California's procurement of new renewables to meet a 50% RPS by 2030;
  - Reduced battery storage costs: Reduced capital cost, added inverter replacement, increased balance-of-systems costs, reduced fixed O&M, adjusted lifetime;
  - Also reduced the cost of solar, wind, and geothermal resources;
  - Allowed hydroelectric and storage resources to provide frequency response services to the system;
- Revised the hypothetical regional footprint for 2020 to include only CAISO and PacifiCorp, rather than a larger footprint;
- Revised the hypothetical regional footprint for 2030 to include the U.S. portion of WECC without the Federal Power Marketing Agencies ("PMAs") (BPA and WAPA), rather than all of U.S. WECC; [1]
- Adjusted to a statewide focus, rather than just CAISO focus;
  - Assumed renewable procurement for non-ISO areas in California (LADWP, BANC, TID, IID) to meet 50% RPS by 2030; and
  - Estimated ratepayer impacts for the State of California as a whole, rather than just for CAISO;
- Did not attribute regionalization impacts to specific parties (other than disadvantaged communities);

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1 Specifically, the PMAs being excluded for the analysis are Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. WAPA's Sierra Nevada Region is included in the Balancing Area of North California and, because it is not a separate balancing area, was included in the analysis.

- Measured WECC-wide impacts from a societal perspective as an additional metric, although not required by SB 350;
- Conducted various sensitivities as suggested by various stakeholders, including:
  - Sensitivities on renewables investment cost impacts: high energy efficiency under SB 350; high flexible load deployment, low portfolio diversity, high rooftop PV, high out-of-state resource availability, lower cost solar, 55% RPS;
  - Sensitivities on production cost impacts:
    - Sensitivities assuming a CO_2 price in the rest of U.S. WECC in 2030;
    - A sensitivity assuming a broader regionalization footprint in 2020, to better understand the impact of renewables intensity and market conditions on results;
    - A sensitivity on 2030 regionalization with no change in California's renewable portfolio, to better understand the impact of de-hurdling and reserve sharing on results;
    - A sensitivity on 2030 regionalization without additional renewables development beyond meeting RPS;
- Ensured compliance with RPS in the rest of U.S. WECC, including Oregon's new 50% by 2040 RPS;
- Incorporated additional announced coal retirements, and renewable and conventional plant additions from several utility integrated resource plans (IRPs);
- Evaluated California and the rest of U.S. WECC's ability to meet the EPA's Clean Power Plan mass-based targets;
- Updated demand, energy efficiency, and various demand-side resource inputs with the CEC's 2015 Integrated Energy Policy Report results.

D. SUMMARY OF STAKEHOLDER COMMENTS

Figure 2 summarizes the names and types of stakeholders active in the SB 350 study. These stakeholders submitted formal comments after the February 8, 2016 and May 24–25, 2016 stakeholder workshops. Several of these stakeholders also submitted informal questions and data requests, participated in supplemental webinars, and reviewed the study team's work papers containing input assumptions, methodology, and results. A glossary of stakeholder names is included at the end of this volume.

Figure 2: Summary of Stakeholders to the SB 350 Study

Type	Stakeholder
Transmission Owner	PacifiCorp, PG&E, SDG&E, Six Cities, SCE, TANC, TransCanyon, TransWest
Generator / Storage	AWEA, Calpine, CESA, Diamond, LSA, LS Power, MegaWatt Storage, NRG, SWPG, Stone Hill, WSP
Power Marketers	Powerex
Municipal Utility	BAMx, CMUA, , IID, LADWP, MID, SVP, SCL
State Agency	CDWR
Federal Power Marketing Agency	BPA
Public Power Agencies	NCPA , PGP, PPC
Environmental	CBE, Defenders, Greenlining/APEN, NRDC, NEC, Sierra Club, UCS, WRA, WGG, WCEA
Customers	CLECA, ICNU, ORA, TURN
Labor	Adams Broadwell
Regulator*	CARB, CPUC, CEC, Peak Reliability

*The CARB and the CEC did not submit formal written comments, but they provided feedback informally to the ISO.

Through the formal comment periods, the study team requested comments relating to 17 topics from the first stakeholder workshop on February 8th, and an additional 9 topics from the second workshop on May 24 -25. Those topics and a summary of stakeholder comments are as follows. This summary is highly condensed, and a more detailed account of stakeholder comments, along with the ISO's formal responses, can be found on the SB 350 website.[2] In addition to these formal comments we received over 75 informal clarifying questions and data requests prior to the production of our final report which can also be found on the CAISO's SB 350 study website.

The February 8, 2016 stakeholder workshop focused on study assumptions and methodology. After the workshop, the ISO requested comments on 17 topics. Below is a summary of the types of comments the study team received:

[2] https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

1. **Do you think the proposed study framework meets the intent of the studies required by SB 350? If no, what additional study areas do you believe need to be included and why?**

   Stakeholders made a number of requests to clarify specific assumptions and inputs to the study. There were some questions on how the SB 350 study aligns with a parallel study on CAISO-PacifiCorp Energy Imbalance Market ("EIM") integration. Several stakeholders commented that the study framework appears to meet SB 350's requirements. However, we received comments that assuming all of U.S. WECC forms a Regional ISO would be unrealistic, and that we should consider a case with only CAISO and PacifiCorp as a regional entity. We also received a number of comments on the renewable portfolio analysis and some requests to change the methodology of that analysis and specific assumptions. Stakeholders commented that our impacts should be measured statewide, instead of just for CAISO consistent with the legislation. Stakeholders made suggestions for additional benefits to consider, sensitivities to consider, and more detailed modeling inputs and analyses.

2. **Five separate 50% renewable portfolios are being proposed for 2030 as plausible scenarios for the purpose of assessing the potential benefits of a regional market. Are these portfolios reasonable for that purpose, and if no, why?**

   Stakeholders made a number of comments on how we should treat in-state versus out-of-state procurement overall and in relation to regionalization, the composition of the renewable portfolios by technology (e.g., wind, solar, geothermal), new transmission relating to the renewable portfolios, and existing renewables outside of California to meet California's 50% RPS.

3. **To develop the five renewable portfolios the RESOLVE model makes a number of assumptions resulting in a mix of renewable and integration resources for the scenario analysis (rooftop solar, storage, retirements, out of state resources etc.) Do you think the assumptions associated with developing the renewable portfolios are plausible? If no, why not?**

   Several stakeholders requested that the assumptions include data from the CEC's 2015 Integrated Energy Policy Report. Stakeholders also made suggestions for assumptions on energy efficiency, demand response, electric vehicle adoption and charging profiles, load, and load sensitivities. There were comments on assumptions for renewable technology costs, the extent of distributed solar development, renewable contract arrangements, and additional transmission. There were also some questions about assumptions on pumped storage, other storage, geothermal resources, and, again, in-state versus out-of-state procurement in relation to regionalization.

4. **The renewable portfolio analysis assumes certain costs and locations for the various renewable technologies. Do you think the assumptions are reasonable? If no, why not?**

   We received several comments from stakeholders that our preliminary assumptions on the cost of solar development were too high. Stakeholders requested us to use the CPUC's RPS calculator for some assumptions on resource cost by technology and geography. There were a number of comments overlapping with the topics already discussed above, including why we included new geothermal and pumped storage resources in the renewable portfolios.

5. **The renewable portfolio analysis makes assumptions about the availability and quantity of out-of-state renewable energy credits ("RECs") to California. Do you think the assumptions are plausible? If no, why not?**

   Stakeholders had a number of comments and questions on how the RPS Product Content Categories (i.e., RPS "buckets") would work in the future under regionalization.

6. **The renewable portfolio analysis makes assumptions about the ability to export surplus generation out of California (i.e., net-export assumptions). Do you think these assumptions are reasonable? If no, why not?**

   Many stakeholders were focused on whether or not, and to what degree, CAISO's system would be physically limited in the future. Some commented that our assumed export limits were too high, and others commented that our assumed export limits were too low and overestimated California's ability to export oversupply of renewable energy. Several stakeholders supported modeling a range of export assumptions.

7. **Does Brattle's approach for analysis of potential impact on California ratepayers omit any category of potential impact that should be included? If so, what else should be included?**

   Several stakeholders had questions about how benefits would be allocated, and some asked for more granular metrics to assess benefits for more specific stakeholders. A few stakeholders pointed out possible reliability benefits or other benefits the study team should consider. Some also pointed out the importance of estimating unit-specific effects. There were some requests to evaluate potential changes in transmission access charges.

8. **Are the methodology and assumptions to estimate the potential impact on California ratepayers reasonable? If not, please explain.**

   Responses were similar to those for question #7 above, including comments on benefits allocation, and treatment of transmission access charges. One stakeholder made suggestions for properly capturing savings in operating reserve costs.

9. **The regional market benefits will be assessed based assuming a regional market footprint comprised of the U.S. portion of the Western Interconnection. Do you believe this is a reasonable assumption for the purpose of this study? If not, please explain.**

   We received a wide range of comments, with stakeholders suggesting footprints from CAISO plus PacifiCorp only, to all of WECC including the non-U.S. portions of WECC. Most stakeholders expressed that assuming all of WECC or all of the U.S. portion of WECC would not be reasonable. One stakeholder pointed out in some detail the barriers to federally-owned and operated areas, such as BPA and WAPA, to joining a Regional ISO.

10. **For the purpose of the production cost simulations, Brattle proposes to use CEC carbon price forecasts for California and TEPPC policy cases to reflect carbon policy implementation in rest of WECC. Is this a reasonable approach? If not, please explain.**

    Stakeholders generally supported the use of the CEC's greenhouse gas price forecast in the 2015 Integrated Energy Policy Report. Stakeholders also pointed out significant uncertainty in the timing and implementation of the EPA's Clean Power Plan. Some stakeholders requested our analysis to include emissions from non-CO_2 greenhouse gases, lifecycle emissions for power plants, and emissions from other sectors.

11. **BEAR will be using existing economic data, and generation and transmission data from E3, the ISO, and Brattle. These data are currently being developed. Are there specific topics that you want to be sure to be addressed regarding these data?**

    We received comments from only a few stakeholders on this topic. Individual comments included a request for an analysis of how investments in other states would affect California, suggestions on what types of entities would be affected economically, a request to develop and evaluate ISO performance metrics, and comments on storage and transmission costs.

12. **The economic analysis will focus on the electricity, transportation, and technology sectors to develop the economic estimates of employment, gross state product, personal income, enterprise income, and state tax revenue. These results will be further disaggregated by sector, occupation, and household income decile. Do you think these sectors are the appropriate ones on which to focus the job and economic impact analysis? If no, why?**

    We received comments from only a few stakeholders on this topic. Individual comments included a request to consider more detailed employment effects of distributed solar resource development, requests to consider the entire value chain of economic activities, and a request to consider impacts on specific groups of people.

13. **Under the proposed study framework, both economic and environmental impacts of disadvantaged communities will be studied. Based on the study overview do you think this satisfies the requirements of SB 350?**

    Again, we received comments from only a few stakeholders on this topic. Individual comments included a request to consider certain labor initiatives, and a request to look at health-related benefits more closely.

14. **The BEAR model will evaluate direct, indirect, and induced impacts to income and jobs, including those in disadvantaged communities. Do you think additional economic analysis is required? If yes, what additional analysis is needed and why?**

    We received comments from only a few stakeholders on this topic. Comments were repetitive to those received for question #13 above.

15. **The environmental analysis will evaluate impacts to California and the west in five areas—air quality, GHG, land, biological, and water supply. Do you think additional environmental analysis is required? If yes, what additional analysis is needed and why?**

    Stakeholder comments on greenhouse gas emissions included a suggestion that regionalization could lead other states to increase their RPS, a request to look at the impacts on regionalizing only CAISO plus PacifiCorp, and a request to consider changes in greenhouse gas-related costs and to clarify some specific assumptions relevant to greenhouse gas emissions. Regarding land use impacts, several comments advised us to rely on a number of existing studies and regulations as a baseline. For our estimates of water impacts one stakeholder suggested an emphasis on water use, and provided data on previous studies of water use by technology. Another stakeholder made suggestions on additional environmental impacts to consider.

16. **The environmental analysis presentation identified a number of potential indicators for the various impacts. Are the indicators sufficient? If no, what additional indicators would you suggest?**

    Several stakeholder comments included suggestions to measure impacts at specific levels of geographic granularity (e.g., by air basin). One stakeholder suggested adding indicators on: federal solar Programmatic Environmental Impact Statement zones, state efforts to limit solar development to specific areas, monitoring and mitigation processes, and federal avian permitting criteria.

17. **Other comments.**

    Many stakeholders raised concerns about the compressed study timeline. We also received several requests to provide additional data and detail on our study assumptions and modeling efforts. A few stakeholders stressed the importance of sensitivity analysis and/or supplemental or follow-up analyses that may be necessary. There were also a few comments on specific assumptions.

The May 24 – 25, 2016 stakeholder workshop focused on the preliminary results of the SB 350 study. After the workshop, the ISO requested comments on 9 topics. Below is a summary of the types of comments the study team received:

1. **Are any of the study results presented at the stakeholder workshop unclear, or in need of additional explanation in the study's final report?**

   Stakeholders requested clarification on the studies sensitivities and ranges of results, how the Energy Imbalance Market relates to study results, how Transmission Access Charges are treated, and how various assumed hurdles under the Current Practice scenarios are defined. Some stakeholders also re-visited assumptions to the renewables portfolio analysis

2. **Comments on the 50% renewable portfolios in 2030.**

   Many stakeholders commented on the cost and availability of future transmission, and its impact on future renewables integration. Stakeholders re-visited assumptions for wind and solar, and some presented viewpoints on the inclusion of "non-economic" geothermal and storage resources assumed. Stakeholders made a wide variety of requests for alternative assumptions for the cost and availability of renewable resources, the level of energy efficiency, and coal retirements.

3. **Comments on the assumed regional market footprint in 2020 and 2030.**

   Some stakeholders commented that additional combinations of different regional market footprint should be tested in the analysis. For instance, some discussed that since the benefits of the regional is dependent on the size and configuration of the footprint, both smaller (just CAISO plus PacifiCorp, and NV Energy) and larger footprint (one that includes all of U.S. portion of WECC) should be analyzed.

4. **Comments on the electricity system (production simulation) modeling.**

   We received a wide variety of comments, including comments on market inefficiencies, wind development, natural gas-fired generation, carbon pricing across WECC, the grid management charge savings assumptions, export limits and renewable resource curtailments, and TEAM and ratepayer calculations. Many comments included requests for clarifications and/or comments on the limitations in the modeling and further elaborations about how the modeling approach used drive conservatively low benefits, even though the real benefits would be much larger than those estimated by the study team. Some stakeholders requested additional sensitivity analyses and the use of a variety of alternative assumptions in either the baseline analyses or in additional sensitivity analyses. Stakeholders also provided comments about the resulting GHG emissions, particularly comments about how to interpret the *de minimus* amount of GHG emission increase estimate for 2020 even though the estimated longer term effects of the regional market would be a material reduction of GHG emissions from the power sector.

5. **Comments on the reliability benefits and integration of renewable energy resources.**

   There were many clarifying questions and suggestions for estimating reliability impacts. Stakeholders asked about assumptions to the load diversity analysis and offered alternative assumptions. Some stakeholders requested further information about the amount of renewable resource development that is beyond those needed to meet the region's collective RPS requirements. Some asked for the analytical results without the "Beyond-RPS" renewable development.

6. **Comments on economic analysis.**

   There were several comments and questions on the more granular sub-state results and some clarifying questions.

7. **Comments on environmental analysis.**

   We received relatively few comments on this topic; many of them requested clarifications or additional detail on our results.

8. **Disadvantaged Communities Analysis**

   We did not receive any comments on the analysis for disadvantaged communities, but many of the comments on economic and environmental analyses apply to the disadvantaged communities as well.

9. **Do stakeholders have any additional comments?**

   Many stakeholders expressed concern over the study timeline and requested more time to conduct the study. Some stakeholders requested more study of how other states outside of California would benefit from the regional market and suggested that since the data is available, the study should include a description of other states' benefits.

F. Glossary of Stakeholder Names

Adams Broadwell	Adams Broadwell Joseph & Cardozo
AWEA	American Wind Energy Association and Interwest Energy Alliance
BAMx	Bay Area Municipal Transmission Group
BPA	Bonneville Power Administration
Calpine	Calpine Corporation
CARB	California Air Resources Board
CBE	Communities for a Better Environment
CDWR	California Department of Water Resources
CEC	California Energy Commission
CESA	California Energy Storage Alliance
CLECA	California Large Energy Consumers Association
CMUA	California Municipal Utilities Association
CPUC	California Public Utilities Commission
Defenders	Defenders of Wildlife
Diamond	Diamond Generating Corporation
Greenling/APEN	The Greenlining Institute and Asian Pacific Environmental Network
ICNU	The Industrial Customers of Northwest Utilities
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water & Power
LSA	Large-Scale Solar Association
LS Power	LS Power Development, LLC
MegaWatt Storage	MegaWatt Storage Farms, Inc.
MID	Modesto Irrigation District
NCPA	Northern California Power Agency
NEC	Northwest Energy Coalition
NRDC	Natural Resources Defense Council, Western Grid Group, Western Resource Advocates, Utah Clean Energy, Northwest Energy Coalition, Islands Energy Coalition and Vote Solar
NRG	NRG Energy, Inc.
ORA	The Office of Ratepayer Advocates
PacifiCorp	PacifiCorp
Peak Reliability	Peak Reliability
PG&E	Pacific Gas and Electric Company

PGP	Public Generating Pool
Powerex	Powerex Corp.
PPC	Public Power Council
SCE	Southern California Edison
SCL	Seattle City Light
SDG&E	San Diego Gas & Electric
Sierra Club	Sierra Club
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California
Stone Hill	Stone Hill CP, LLC
SVP	Silicon Valley Power
SWPG	SouthWestern Power Group
TANC	Transmission Agency of Northern California
TransCanyon	TransCanyon, LLC
TransWest	TransWest Express LLC
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists on behalf of the Environmental Defense Fund ("EDF") and the Center for Energy Efficiency and Renewable Technologies ("CEERT")
WCEA	Western Clean Energy Advocates
WGG	Western Grid Group
WRA	Western Resource Advocates
WSP	Westlands Solar Park

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Senate Bill 350 Study

Volume III: Description of Scenarios and Sensitivities

PREPARED FOR

California ISO

PREPARED BY

The Brattle Group

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Aspen Environmental Group

July 8, 2016

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

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Volume III. Description of Scenarios and Sensitivities

A. INTRODUCTION

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate or regional entity ("Regional ISO").

At the foundation of the study it was necessary to define an analytical framework that would allow the study team to estimate the impact of having a regional market in the west. Such an analytical framework would include simulations of the west without a Regional ISO and comparison simulations with some level of regionalization. The comparison of the simulated results would then reflect the estimated impact of regionalization. With this approach, we solicited stakeholder input early in the process to ensure that the design of the scenarios incorporated stakeholder feedback and comments.[1]

With stakeholder input, the study team developed five baseline scenarios to evaluate. The first two scenarios reflect near-term market conditions: one with and one without a limited definition of a Regional ISO. The limited Regional ISO includes the current CAISO and PacifiCorp ("2020 CAISO+PAC") and is compared to "2020 Current Practice."

The three other scenarios reflect longer-term market conditions—in 2030—when California is expected to procure enough new renewables to meet its 50% Renewables Portfolio Standard ("50% RPS"). One of the 2030 cases ("2030 Current Practice 1") assumes no regional market and incorporates the existing practice of having to conduct bilateral trading with entities in the West outside of the existing CAISO. This scenario, in effect, assumes that excess intermittent renewable generation from California in 2030 will face barriers when selling to the rest of the west in large quantities (i.e., when a significant amount of wind and solar capacity is on the California system and when solar output from California is at its maximum).

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[1] Further detail of the stakeholder process is included in Volume II of this report.

The remaining two 2030 baseline cases assume an expanded Regional ISO that includes all of the U.S. WECC without the federal Power Marketing Agencies ("PMAs") Bonneville Power Administration ("BPA") and the Western Area Power Administration ("WAPA").[2] These two Regional ISO cases reflect the efficiencies of broader regionalization, and they reflect two alternative renewable portfolio procurement possibilities: one to meet California's 50% RPS with an in-state procurement focus ("2030 Expanded Regional ISO 2") and one with a more out-of-state procurement focus ("2030 Expanded Regional ISO 3").

In response to stakeholder feedback, we also conducted a number of sensitivities to our analyses, with a focus on assumptions that could change our estimates of emissions impacts and ratepayer impacts.

Sections B and C of this Volume of our report describe in more detail the study's key assumptions, the scope of regionalization, and the definition of the five baseline scenarios. Section D provides a summary of the sensitivities analyzed.

B. SCOPE OF A REGIONAL MARKET

The language of the SB 350 legislation does not define a specific scope for regionalization, neither in terms of the footprint of electric service areas that would be part of a Regional ISO, nor in terms of when load-serving entities might choose to join a Regional ISO. However, the question is informed by a request from PacifiCorp to explore the impact of consolidating the CAISO and PacifiCorp balancing areas into a single balancing area, and of expanding the CAISO markets to the larger balancing area that would benefit both entities' ratepayers.

We defined two possible footprints of a Regional ISO which cover a range, from a very limited footprint with only CAISO plus PacifiCorp, to an expanded Regional ISO that covers almost the entire U.S. WECC region. We defined two future snapshots of possible market conditions that

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2 Specifically, the PMAs excluded for the purpose of this analysis are Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. WAPA's Sierra Nevada Region is included in the Balancing Area of North California and, because it is not a separate balancing area, was included in the analysis. The PMAs were excluded solely for providing a smaller geographic footprint. This choice does not reflect any suggestion that the PMAs would not be interested in participating in a regional market. In fact, in the eastern interconnection, WAPA's Upper Great Plains Region has already joined the Southwest Power Pool.

would set the stage for expanded regionalization: a near-term year, 2020, with a regulatory framework and market conditions similar to today's, and a more distant year, 2030, when California and other western states are expected to have made major changes to how electricity is supplied, with significantly more renewables and less fossil fuel use. The combination of these assumptions on regional footprint and market conditions forms the basis for our baseline scenarios.

1. Regional Market Footprint

Figure 1 illustrates the two regional market footprints we analyze. The first assumes only CAISO and PacifiCorp form a regional entity. The second assumes that all of U.S. WECC, with the exception of the PMAs, forms an expanded Regional ISO. These footprints are hypothetical and are designed to capture a plausible range of impacts. We understand that the individual utilities and states will have to conduct their own evaluations of the benefits and tradeoffs of joining a regional entity, and to decide whether or not to join one.

Both of these assumed footprints were developed based on feedback from the stakeholders of the SB 350 study. Several stakeholders expressed the desire to reflect conservative regional footprints, including a case that assumes only CAISO and PacifiCorp form a regional entity. This case was viewed by several stakeholders as a tangible near-term representation of a Regional ISO due to PacifiCorp's expressed interest (in 2015) in becoming a full ISO member. If PacifiCorp were to become a Participating Transmission Owner, it would remain to be seen whether other utilities and states would also choose to join the Regional ISO and broaden the regional footprint.[3]

Based on the experience with the Energy Imbalance Market, and with regional markets in other areas of the country, the study team finds it unlikely that the regional market would be confined to the ISO and PacifiCorp by 2030 or beyond. Since the 2020 case presents a bookend analysis of a very limited regional market in the near-term, the study team believed it appropriate to model a more realistic larger regional market for the longer-term. This is particularly important since entities are likely to continue to join even beyond 2030. While the study team is confident that additional entities would join the regional market, it is impossible at this time to know which

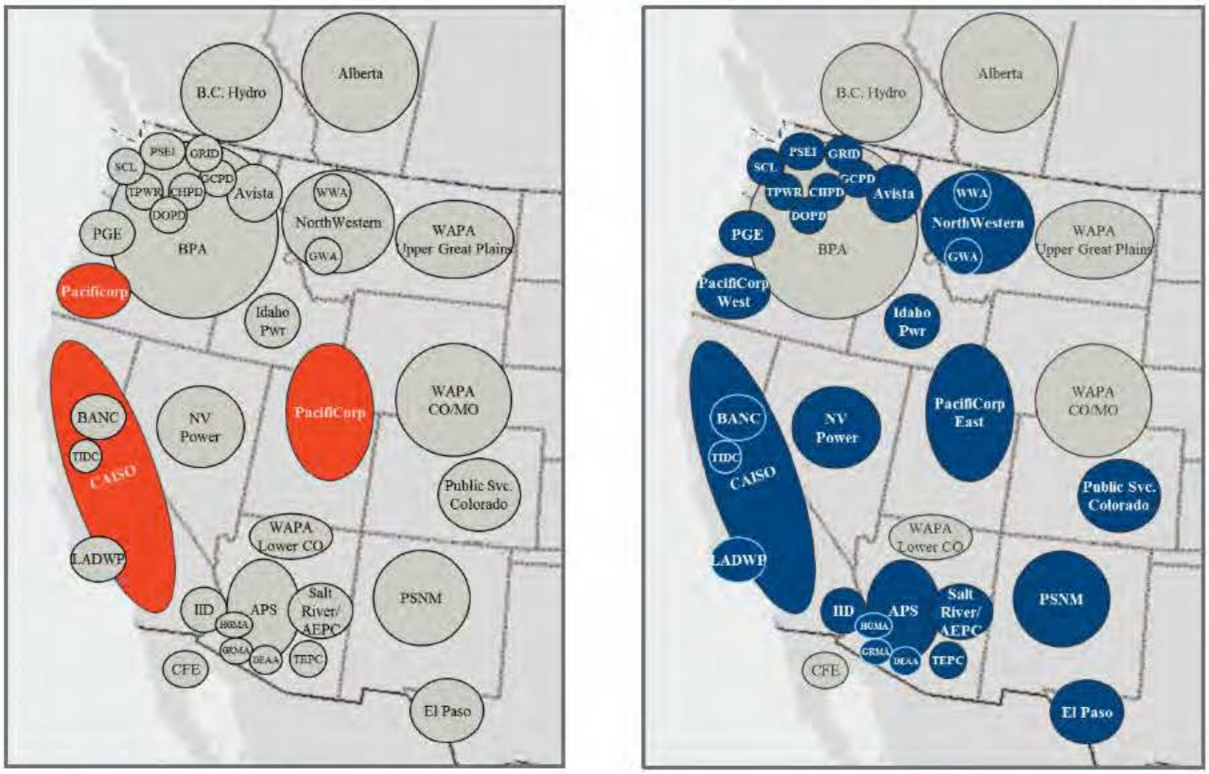
[3] A Participating Transmission Owner turns over operational control of their transmission system and their balancing area is' subsumed within the CAISO balancing area.

and how many entities would join by 2030, which would join after 2030, and which would not join until later (or not at all).

Figure 1: Regional Market Footprints Analyzed

CAISO + PAC

U.S. WECC without Federal Power Marketing Agencies



Several stakeholders expressed that an expanded Regional ISO that included all of the U.S. WECC service areas would not be realistic. They wanted a more conservative view of broad regionalization. In response, we developed a baseline case that assumes that all of U.S. WECC, with the exception of the PMAs, participates in a Regional ISO ("U.S. WECC without PMAs"). BPA and WAPA did not request to be excluded from our hypothetical regional footprints. In response to stakeholders, we restricted the definition of broad regionalization, and BPA and WAPA were chosen for exclusion simply by virtue of their unique operational and regulatory situation. The study team believed it unlikely that the Canadian and Mexican entities would join the regional market by 2030, even though Manitoba Hydro is a member of the Midcontinent ISO.

Beyond the considerations described above, the study team did not wish to speculate whether any particular group of entities in the West (EIM participants, investor-owned utilities, publicly-owned utilities, California utilities, etc.) would be more or less likely to join the regional market.

2. Representative Years

The study evaluates regional market impacts for two representative years:

- **2020:** As introduced above, 2020 is selected to represent near-term market conditions similar to today's, both in terms of policies and other market fundamentals. PacifiCorp is currently targeting implementation of the Regional ISO, if approved by various regulatory authorities, in 2019. In 2020 we expect that California will meet its 33% RPS (resources are already mostly contracted as of 2016), retirements and replacements to meet the state's Once-Through Cooling requirements will not yet be completed, Diablo Canyon will not yet be retired, the state's energy storage requirements will not yet be due, and the EPA's Clean Power Plan will not yet be implemented. We also expect that the demand for electricity will look similar to today's, and so will various investment costs and operating costs (particularly natural gas and coal prices), in California and in the rest of WECC. By analyzing 2020 we are asking, "How could regionalization impact a world with which we're familiar?" We recognize that even if PacifiCorp becomes a Participating Transmission Owner by 2020, it is only at the early stage of that expanded market, thus, 2020 can be viewed as a year that represents the "beginning" of an expanded market structure; one that will evolve gradually over time.
- **2030:** This year is selected to represent simulated longer-term market conditions with higher demand for electricity and a very different supply stack for electricity across the West. For instance, by 2030, we anticipate a significant amount of natural gas-fired capacity will be retired in California to meet Once-Through Cooling requirements, and California is expected to develop sufficient amount of new renewable energy resources to meet its 50% RPS. In the rest of U.S. portion of WECC, we expect that load will have grown relative to the near-term rate (e.g. 1.2% per year from 2020), a significant amount of coal-fired capacity will have been retired, and other states in the West will have developed significant amount of additional renewables to meet those states' respective RPS (already set today, but growing in proportion through 2030). By analyzing 2030 we are asking, "How could regionalization impact a world with relatively high renewables resources deployed and less fossil fuel use?"

C. Baseline Scenarios (5)

Figure 2 below provides a summary of the 5 baseline scenarios, which combine the near-term market outlook (2020) with a minimal Regional ISO footprint (CAISO + PAC), and the longer-term market outlook (2030) with an expanded Regional ISO footprint (U.S. WECC without PMAs).

- 2020 Current Practice: reflects near-term market conditions. California has developed enough renewables to meet its 33% RPS. CAISO operates as-is with no regionalization.
- 2020 CAISO+PAC: reflects near-term market conditions. California has developed enough renewables to meet its 33% RPS. CAISO and PacifiCorp form a Regional ISO. Up to 776 MW in energy transfers between CAISO and PacifiCorp are free of economic and operational hurdles. CAISO and PacifiCorp resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements for the expanded balancing area. PacifiCorp's coal fleet faces the same generic natural gas-based greenhouse gas emissions hurdle to serve California load as in the Current Practice case.[4] This scenario is compared to the 2020 Current Practice scenario to evaluate the impacts of extremely limited regionalization.
- 2030 Current Practice 1: reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with a business-as-usual in-state procurement focus. CAISO operates as-is with no regionalization. Bilateral markets and trading frictions limit the sales of excess generation from the portfolios of CAISO entities to 2,000 MW. This means it is assumed in this Current Practice 1 scenario that bilateral markets would accommodate the re-export of all prevailing existing imports (ranging from 3,000-4,000 MW per hour) plus export an additional 2,000 MW of (mostly intermittent) renewable resources.
- 2030 Expanded Regional ISO 2 (or "Regional 2"): reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with an in-state procurement focus. All of U.S. WECC without PMAs has formed a Regional ISO. All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from

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4 This assumption is based on today's administrative rules under California's AB 32. In reality, with regionalization this administrative carbon hurdle would likely be revisited by the California Air Resources Board to ensure greenhouse gas emissions from PacifiCorp's coal fleet are properly treated under California's greenhouse gas cap-and-trade system.

California's renewables portfolio is more readily absorbed by the regional marketplace (reflected in a more relaxed 8,000 MW physical CAISO export limit). This scenario is compared to the 2030 Current Practice 1 scenario to evaluate the impacts of broader (but still limited) regionalization.

- 2030 Expanded Regional ISO 3 (or "Regional 3"): reflects longer-term market conditions. California has developed enough renewables to meet its 50% RPS, with more of an out-of-state procurement focus compared to Regional 2. All of U.S. WECC without PMAs has formed a Regional ISO. All energy transfers among the Regional ISO members are free of economic and operational hurdles. Regional ISO resources are committed and dispatched in a coordinated fashion to meet combined energy and operating reserves requirements. Oversupply from California's renewables portfolio is more readily absorbed by the regional marketplace (reflected in a more relaxed 8,000 MW physical CAISO export limit). This scenario is compared to the 2030 Current Practice 1 scenario to evaluate the impacts of broader (but still limited) regionalization.

Overall study results for these five scenarios are discussed in Volume I of the SB 350 study.

Figure 2: Key Assumptions to SB 350 Study Baseline Scenarios

Scenario	Regional ISO Footprint	California's Renewable Portfolio	Market Conditions	CAISO's Ability to Sell Power to Rest of West	Focus of Analysis
2020 Current Practice	None; CAISO as-is	Already contracted for 33%	Near-term	Net exports from CAISO limited to 0 MW[5] (but CAISO is a net importer)	Baseline
2020 CAISO + PAC	Limited to only CAISO plus PacifiCorp	Already contracted for 33%	Near-term	Transfers between CAISO and PAC limited to 776 MW	Impact of limited near-term regional market with CAISO+PAC only
2030 Current Practice 1	None; CAISO as-is	RESOLVE portfolio for Current Practice 1 to meet 50%	Longer-term	2,000 MW limit on net bilateral sales	Baseline
2030 Expanded Regional ISO 2 **(Regional 2)**	All of U.S. WECC without PMAs (BPA and WAPA)	RESOLVE portfolio for Regional 2 to meet 50%	Longer-term	8,000 MW limit on physical exports (no other limit on net bilateral sales)	Impact of regional market under current renewable procurement practices
2030 Expanded Regional ISO 3 **(Regional 3)**	All of U.S. WECC without PMAs (BPA and WAPA)	RESOLVE portfolio for Regional 3 to meet 50%	Longer-term	8,000 MW limit on physical exports (no other limit on net bilateral sales)	Impact of greater regional renewable procurement

D. Sensitivity Analyses

To ensure that the analyses are robust, and to address various stakeholders' requests, the study team used sensitivity analyses to test how numerous alternative assumptions would affect the results of the SB 350 study. Figure 3 summarizes all the sensitivity analyses conducted, including key differences to baseline scenarios as well as the analytical scope (and analytical tools) that were applied to these sensitivities.

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5 California has been a net import since the 1960s, thus a net export of 0 would be considered current practice.

Figure 3: Key Assumptions for SB 350 Study Sensitivities

Sensitivity	Focus of Analysis Impact of…	Key Inputs	Analytical Scope (Tool) Renewable Investment Costs (RESOLVE)	Production Costs and Emissions (PSO)	CA Production, Purchase, & Sales Cost (TEAM)
2030 Current Practice 1B*	High coordination under bilateral markets, even without regionalization	Increase limit on net bilateral sales to 8,000 MW	✓*	✓*	✓*
High Energy Efficiency	Significantly more energy efficiency savings by 2030 in California	Double California's projected "Additional Achievable Energy Efficiency"	✓		
High Flexible Loads	More resources to respond to California's oversupply	Add 3,000 MW of flexible loads in all 2030 cases	✓		
Low Portfolio Diversity	Fewer technology options to meet California's 50% RPS	Remove assumed new pumped hydro and geothermal resources	✓		
High Rooftop PV	More solar, rather than wind, development to meet California's 50% RPS	Increase CAISO rooftop PV from 16 GW to 21 GW by 2030	✓		
High Out-of-State Resource Availability	More REC-only procurement from out-of-state, rather than solar and wind development for California's 50% RPS	Increase available SW Solar and NW Wind RECs to half of the 50% RPS goal (IOUs only)	✓		
Low Cost Solar	Continued steep reductions in solar development costs for many years	Reduce solar cost to \$1/W by 2025	✓		
55% RPS	RPS that may better support a goal of 40% GHG reduction by 2030 and/or PG&E's goals to replace Diablo Canyon	Increase California RPS to 55% in all 2030 scenarios	✓		
2020 Expanded Regional ISO	An expanded regional footprint under near-term market conditions	Expand 2020 regional footprint to all of U.S. WECC without PMAs		✓	✓
2030 Regional ISO 1	Holding the renewable portfolio constant, isolate the impacts of de-hurdling and reserve sharing	<u>Current Practice 1</u> renewable portfolio, with expanded Regional ISO that reflects de-hurdling and reserve-sharing in U.S. WECC minus PMAs		✓	
2030 Regional ISO 3 w/o Renewables Beyond RPS	Barriers to the regional marketplace attracting renewables development beyond RPS	Remove 5,000 MW of additional renewables beyond states' RPS		✓	✓
2030 with WECC-Wide CO_2 Price	Federal carbon constraints	\$15/ton CO_2 price in the rest of U.S. WECC (in Current Practice 1 and Regional 3)		✓	
Low Willingness to Buy in Bilateral Market	California having to pay others to take power during oversupply conditions	Decrease transaction floor price from \$0 to -\$40/MWh			✓

*Sensitivity 2030 Current Practice 1B was also evaluated in the economic and environmental studies.

Note: The economic impact analysis also looked at a hypothetical reference case that holds California's 33% RPS by 2020 constant through 2030. That case is not included in this table, and it is discussed in Volume VIII of the SB 350 study.

As shown in the table above, the “2030 Current Practice 1B” sensitivity was analyzed throughout the SB 350 study, and the results for this sensitivity are discussed in Volume I. Sensitivities evaluated for the purpose renewables investment cost analysis are discussed in more detail in Volume IV. Sensitivities evaluated in our production cost and emissions analyses are discussed in Volume V and Volume IX. Sensitivity analyses surrounding changes in assumptions in the calculations of California production, purchase, and sales cost (utilizing the CAISO’s “TEAM” framework) are discussed in Volume V. A ratepayer impact analysis was undertaken for each sensitivity for which the TEAM framework was applied. The results of these ratepayer impact sensitivities are discussed in Volume VII.

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Senate Bill 350 Study

Volume IV: Renewable Energy Portfolio Analysis

PREPARED FOR

California ISO

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Table of Contents

1 Executive Summary

1.1 Overview

E3 was retained by the California ISO ("ISO") to estimate the renewable energy procurement benefits of a regional market within the context of its studies conducted in response to Senate Bill 350 ("SB 350"). California Load-Serving Entities ("LSEs") must procure portfolios of renewable energy resources in order to comply with California's 50% Renewables Portfolio Standard ("RPS"). A regional market can provide renewable procurement benefits to California in at least two ways. Firstly, regional market operations can provide *integration benefits*, easing the burden of integrating such a large quantity of variable renewable energy resources, reducing the cost of compliance with a 50% RPS. Secondly, a regional transmission organization can facilitate the development of high-quality, remote resources—such as Class V wind resources in Wyoming and New Mexico—by providing grid access through its administration of a regional market and its authority to identify and allocate the costs of any needed new transmission facilities.

E3 identified optimal (i.e. least-cost) renewable portfolios under three scenarios intended to illuminate the two categories of benefit described above. This Volume describes the analysis that E3 undertook to estimate these benefits. E3's analysis addresses the renewable procurement benefits only; other benefits are estimated through the analyses described in the other volumes of this report.

1.2 Methodology

E3's Renewable Energy Solutions model ("RESOLVE") is an optimal investment and operational model designed to inform long-term planning questions around renewable integration in systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon for a study area, in this case the California Independent System Operator ("ISO") footprint. RESOLVE solves for the optimal investments in renewable resources, various energy storage technologies, new gas plants, and gas plant retrofits subject to an annual constraint on delivered renewable energy that reflects the RPS policy, a capacity adequacy constraint to maintain reliability, simplified unit commitment constraints, and scenario-specific constraints on the ability to develop specific renewable resources.

The model is used to quantify the procurement cost of meeting California's RPS targets in the ISO balancing area in different scenarios representing different levels of regionalization. Results for the non-ISO entities in California are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario rather than using RESOLVE for their portfolio determination.

1.3 Data & Inputs

Using the RESOLVE model described above, E3 developed renewable portfolios for three scenarios in California that each meet a 50% RPS in 2030:

+ **Current Practice 1 Scenario:** This scenario assumes that renewable energy procurement is largely from in-state resources, with 5,000 MW of out-of-state resources available over existing transmission. This scenario does not assume an expanded regional market.
+ **Regional 2 Scenario: Regional market operations with "current practice" renewable energy procurement policies:** This scenario assumes expanded regional markets, but assumes no change to current renewable energy procurement policies, i.e., procurement policies continue to favor in-state resources even when out-of-state resources are lower cost.
+ **Regional 3 Scenario: Regional market operations with regional procurement:** This scenario assumes expanded regional markets, as well as regional procurement of out-of-state resources over new transmission.

Table 1. Overview of the three scenarios modeled.

Scenarios	Current Practice 1	Regional 2	Regional 3
ISO export limit (MW)[1]	2,000	8,000	8,000
Procurement	Current Practice	Current Practice	WECC-wide
Operations	ISO	WECC-wide	WECC-wide

Input data on electricity demand, thermal resources and renewables is mostly based on public sources such as the CPUC's RPS calculator, the CEC's 2015 Integrated Energy Policy Report Update ("2015 IEPR"), the 2014 Long Term Procurement Planning proceeding ("LTPP") and the 2024 Transmission Expansion Planning Policy Committee ("TEPPC") Common Case.

A number of sensitivities are analyzed to verify the robustness of the results. Only the ISO inputs and results vary across these sensitivities, results for the non-ISO entities are held constant. The following sensitivities are tested:

[1] In the Current Practice 1 scenario, this limit is applied to all resources procured for California, including out-of-state resources that are delivered to California and must be re-exported. This means it is assumed that bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus export an additional 2,000 MW of (mostly intermittent) renewable resources. In Regional 2 and 3, this limit is relaxed due to the regional market's centralized, optimal dispatch and is applied as a physical transfer limit out of the current ISO footprint as a proxy for a physical simultaneous transfer limit (which does not has not yet been specified).

Table 2. Overview of sensitivities analyzed.

Sensitivity	Description
A. High coordination under bilateral markets	ISO simultaneous export limit is increased from 2,000 MW to 8,000 MW for Current Practice 1, while the procurement and operations are kept business-as-usual and ISO-wide ("Current Practice 1B")
B. High energy efficiency	The additional achievable energy efficiency (AAEE) is doubled by 2030.
C. High flexible loads	3,000 MW of 4-hour batteries are added in all scenarios.
D. Low portfolio diversity	Pumped hydro and geothermal are taken out of the portfolios and total California wind is restricted to 2,000 MW in all scenarios.
E. High rooftop PV	The total installed capacity of rooftop PV in the ISO balancing area is increased from 16 GW to 21 GW by 2030.
F. High out-of-state resource availability	Southwest solar RECs and Northwest wind RECs renewable potential is increased so that they account for up to half of the 50% RPS goal (ISO only, not non-ISO California entities), which equals to a renewable potential of 4,526 MW of Northwest wind RECs and 4,279 MW of Southwest solar RECs.
G. Low cost solar	Solar costs are reduced to $1/W-DC by 2025.
H. 55% RPS	The California RPS goal is increased to 55%.

1.4 Results

Regional markets result in lower renewable procurement costs for California across all scenarios. Renewable procurement cost savings are $680 million/year in 2030 under regional markets with current practices in renewable procurement (Regional 2). Procurement cost savings increase to $799 million/year in 2030 under regional markets with regional renewable procurement (Regional 3).

In both regionalization cases the larger, diversified footprint leads to lower curtailment and less overbuild to meet the RPS target, which lowers renewable procurement costs. Regional 3 shows that California's regional

procurement of Wyoming and New Mexico wind resources over new transmission results in additional cost savings because of the low cost of these resources, even with the additional transmission costs, and its diversification benefits.

The sensitivity results show the renewable procurement cost savings are relatively robust, with savings ranging from $391 to 1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in procurement cost savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings. The highest procurement cost savings occur in the 55% RPS sensitivity, which might become the *de facto* base case after PG&E's recent decision to close Diablo canyon in 2025 and replace its output with renewables.[2]

The tables below show the main base case results, as well as a summary of the sensitivity results:

- Table 3 shows the annual statewide renewable procurement cost that California would be paying in 2030 for resources it procured to go from a 33% RPS to a 50% RPS in each scenario. The cost reflects the annualized procurement cost for all the renewable resources (including storage) to meet California's 50% RPS target by 2030, including transmission costs and an energy credit for REC resources.[3]

[2] See: http://www.utilitydive.com/news/pge-to-close-diablo-canyon-nuclear-plant-replace-it-with-renewables-effi/421297/

[3] *Pricing for REC resources is based on the PPA price of a new resource net of its energy value in local markets. Since this energy credit is not captured explicitly in PSO modeling, it is included here as an explicit adjustment. The energy value of all non-REC renewable resources is captured directly through PSO modeling.

- Table 4 shows the annual renewable curtailment in 2030 in the ISO area modeled by RESOLVE.
- Table 5 and Table 6 show the statewide portfolio that allows California to go from 33% to 50% RPS in 2030, both in MW of installed capacity and GWh of annual generation. The portfolio is additional to existing and planned renewable resources that are assumed to meet the 33% RPS in 2030.
- Table 7 shows a summary of the renewable procurement cost savings across all sensitivities. The cost numbers include the same metrics as the results in table 3, but all results are expressed relative to Current Practice 1 in order to show the procurement cost savings under a regional market.

Table 3. 2030 statewide annual renewable procurement cost and REC revenue ($MM).

Costs ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,297	$2,852	$2,347
Transmission Costs (new construction and wheeling; $M	$234	$0	$273
REC Revenue ($MM)	-$240	-$240	-$127
Net Total Costs	**$3,292**	**$2,612**	**$2,492**
Procurement Savings Relative to Current Practice 1		$680	$799

Table 4. 2030 annual renewable curtailment in ISO balancing area.

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Total Curtailment (GWh)	4,818	1,606	1,226
Curtailment as % of available RPS energy	4.5%	1.6%	1.2%

Table 5. 2030 statewide cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,601	7,804	3,440
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,447	562	318
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,995
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,962
Total CA Resources	**11,101**	**10,204**	**5,840**
Total Out-of-State Resources	**5,551**	**5,166**	**7,694**
Total Renewable Resources	**16,652**	**15,370**	**13,534**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 6. 2030 statewide cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	21,482	22,147	9,827
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,574	891
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	8,037
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	7,905
Total CA Resources	33,904	31,685	19,365
Total Out-of-State Resources	16,654	15,661	27,601
Total Renewable Resources	**50,558**	**47,346**	**46,966**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 7. Summary of 2030 Sensitivity Results

Renewable procurement cost savings from regional market ($MM/year)		Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case		$680	$799
A.	**High coordination under bilateral markets**	$391	$511
B.	**High energy efficiency**	$576	$692
C.	**High flexible loads**	$495	$616
D.	**Low portfolio diversity**	$895	$1,004
E.	**High rooftop PV**	$838	$944
F.	**High out-of-state resource availability**	$578	$661
G.	**Low cost solar**	$510	$647
H.	**55% RPS**	$1,164	$1,341

1.5 Conclusions

Regional markets result in significantly lower renewable procurement costs for California across all scenarios and sensitivities tested in the RESOLVE optimal investment model.

+ Renewable procurement cost savings are $680 million/year in 2030 under regional markets with current practices in renewable procurement.
+ Procurement cost savings are $799 million/year in 2030 under regional markets with regional renewable procurement.
+ Savings range is $391-1,341 million/year in 2030 under regional markets, across all sensitivities.

2 RESOLVE Model Methodology

2.1 Introduction

E3's Renewable Energy Solutions ("RESOLVE") Model is an optimal investment and operational model designed to inform long-term planning questions around renewables integration in California and other systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon with one-hour dispatch resolution for a study area, in this case the California Independent System Operator ("ISO") footprint. The model incorporates a geographically coarse representation of neighboring regions in the West in order to characterize and constrain flows into and out of the ISO. RESOLVE solves for the optimal investments in renewable resources, various energy storage technologies, new gas plants, and gas plant retrofits subject to an annual constraint on delivered renewable energy that reflects the RPS policy, a capacity adequacy constraint to maintain reliability, constraints on operations that are based on a linearized version of the classic zonal unit commitment problem as well as feedback from ISO, and scenario-specific constraints on the ability to develop specific renewable resources.

The RESOLVE model is designed to answer planning and operational questions related to renewable resource integration. In general, these models fall along a spectrum from planning-oriented models with enough treatment of operations to characterize the value of resources in a traditional power system to detailed operational models that include full characterization of renewable integration challenges on multiple time scales but treat planning decisions as exogenous. The California Public Utilities Commission's ("CPUC's") RPS Calculator evaluates solutions on an annual basis without regard to the benefits of a long-term view. The Power System Optimizer ("PSO") model utilized by Brattle as part of this SB 350 analysis is an example of a detailed production simulation dispatch model which takes the renewable resource procurement decisions (along with all other investment or retirement decisions) as exogenous inputs. RESOLVE is used to develop the California renewable resources portfolios that are considered input for the PSO model in the SB 350 study. Below, we provide a description of the RESOLVE model.

2.2 Theory

One economic lens that can be used to evaluate various integration solutions is to consider the consequences of failing to secure the solutions. This is similar to the avoided cost framework, which has been applied broadly to cost-effectiveness questions in the electricity sector and other areas. In a flexibility-constrained system, the default consequence of failing to secure enough operational flexibility to deliver all of the available renewable energy is to curtail some amount of production in the time periods in which the system becomes constrained. In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system a utility may need to procure enough renewables to produce in excess of the energy target in anticipation of curtailment events to ensure compliance with the Renewable Portfolio Standard ("RPS"). This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution, like energy storage, can be conceptualized as the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of the available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

Beyond cost effectiveness, this framework also allows for the determination of an optimal solution by examining the costs and benefits of increasing levels of investment in the integration solutions. If a single integration solution is available to the system, the optimal investment in that solution is the investment level at which the marginal cost of the solution is equal to the marginal benefit in terms of avoided renewable overbuild of the solution. However, as described above, many different strategies can be pursued and the value of each solution will depend on its individual performance characteristics as well as the rest of the solution portfolio. RESOLVE provides a single optimization model to explicitly treat the cost and behavior of specific solutions as well as the interactions between solutions.

2.3 Methodology

The RESOLVE model co-optimizes investment and operational decisions over several years in order to identify least-cost portfolios for meeting renewable energy targets. This section describes the RESOLVE model in terms of its temporal and geographical resolution, characterization of system operations, and investment decisions. Particular attention is placed on topics that are unique to an investment model that seeks to examine renewable integration challenges, including: renewables selection; reserve requirements; energy storage; flexible loads; and day selection and weighting for operational modeling.

2.3.1 TEMPORAL SCOPE AND RESOLUTION

In this analysis, investment decisions are made with 5-year resolution between 2015 and 2030. Operational decisions are made with hourly resolution on a subset of independent days modeled within each investment year. Modeled days are selected to best reflect the long run distributions of key variables like load, wind, solar, and hydro availability. The day selection and weighting methodology is described in more detail below.

For each year, the user defines the portfolio of resources (including conventional, renewable, and storage) that are available to the system without incurring additional fixed costs – these include existing resources, resources that have already been approved, and contracted resources, net of planned retirements. In addition to these resources, the model may be given the option to select additional resources or retrofit existing resources in each year in order to meet an RPS requirement, fulfill a resource adequacy need, or to reduce the total cost. Fixed costs for selected resources are annualized using technology-specific financing assumptions and costs are incurred for new investments over the remaining duration of the simulation. The objective function reflects the net present value of all fixed and operating costs over the simulation horizon, plus an additional *N* years, where the *N* years following the last year in the simulation are assumed to have the same annual costs as the last simulated year, *T*. When the investment decision resolution is coarser than one year, the weights applied to each modeled year in the objective function are determined by approximating the fixed and operating costs in un-modeled years using linear interpolations of the costs in the surrounding modeled years.

2.3.1.1 Operating Day Selection and Weighting

To reduce the problem size, it is necessary to select a subset of days for which operations can be modeled. In order to accurately characterize economic relationships between operational and investment decisions, the selected days and the weights applied to their cost terms in the objective function must reflect the distributions of key variables. In the analysis described here, distributions of the following parameters were specifically of interest: hourly load, hourly wind production, hourly solar production, hourly net load, and daily hydropower availability. In addition, the selection of the modeled days sought to accurately characterize: the number of days per month, average monthly hydropower availability, and site-specific annual capacity factors for key renewable resources.

To select and weight the days according to these criteria or target parameters, an optimization problem was constructed. To construct the problem, a vector, *b*, was created that contained all of the target parameter values and described each target parameter distribution with a set of elements, each of which represents the probability that the parameter falls within a discrete bin. The target values can be constructed from the full set of days that the problem may select or from an even longer historical record if data is available.

For each of the days that can be selected, a vector, *a*, is produced to represent the contribution of the conditions on that day to each of the target parameters. For example, if b_i represents the number of hours in a year in which the load is anticipated to fall within a specified range, a_{ij} will represent the number of hours in day *j* that the load falls within that range. The target parameters vector, *b*, may therefore be represented by a linear combination of the day-specific vectors, a_j, and the day weights can be determined with an optimization problem that minimizes the sum of the square errors of this linear combination. An additional term is included in the objective function to reduce the number of days selected with very small weights and a coefficient, *c*, was applied to this term to tune the number of days for which the selected weight exceeded a threshold. The optimization problem was formulated as follows:

$$\begin{aligned} &\text{minimize} \quad \sum_i \left[\left(\sum_j a_{ij} w_j \right) - b_i \right]^2 - c \sum_j w_j^2 \\ &\text{subject to} \quad \sum_j w_j = 365 \end{aligned}$$

The resulting weights can then be filtered based on the chosen threshold to yield a representative subset of days. This method can be modified based on the specific needs of the problem. For example, in this analysis, while the hourly net load distribution was included in the target parameter vector, cross-correlations between variables were not explicitly treated.

2.3.2 GEOGRAPHIC SCOPE AND RESOLUTION

While RESOLVE selects investment decisions only for the region of interest, in this case the ISO, operations in a highly interconnected region are influenced by circumstances outside the region. For example, the conditions in the Northwest, Southwest, and Los Angeles Department of Water and Power ("LADWP") regions influence the ISO dispatch via economic imports and exports. To capture these effects, RESOLVE includes a zonal dispatch topology with interactions between the zones characterized by a linear transport model. Both the magnitudes of the flows and the ramps in flows over various durations can be constrained based on the scenario. Hurdle rates can also be applied to represent friction between balancing areas. Simultaneous flow constraints can also be applied over collections of interties to constrain interactions with neighboring regions.

The zonal topology for the analysis is shown in Figure 1 – the ISO footprint is the primary zone and the Northwest and Southwest regions and LADWP balancing area are the secondary zones. The Northwest region includes the region encompassed by the U.S. portion of the Northwest Power Pool, plus the Balancing Area of the Northern California. The Southwest region includes New Mexico, Arizona, Southern Nevada, and the Imperial Irrigation District. The flow constraints applied in this analysis are summarized in Table 1. Negative numbers in the table represent exports from California, while positive values represent imports.

Figure 1. Zonal topology

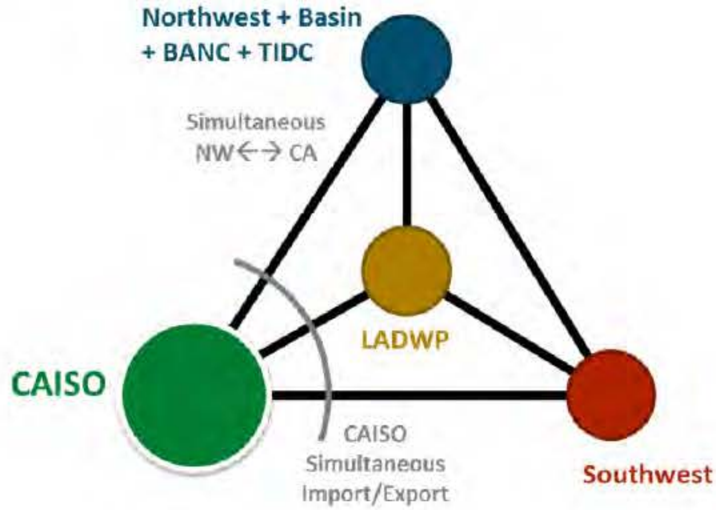


Table 8. Flow constraints between zones and simultaneous flow constraints (negative numbers reflect flows in opposite direction).

Path	Minimum Flow (MW)	Maximum Flow (MW)
SW → ISO	-7,250	6,785
NW → ISO	-5,171	6,364
LADWP → ISO	-2,045	4,186
LADWP → NW	-,2826	2,963
SW → LADWP	-3,373	3,373
NW → SW	-1,480	1,465
Simultaneous NW → CA	-7,934	9,390
ISO Simultaneous Import	-8,000 to -2,000	10,068

2.3.3 INVESTMENT DECISIONS

2.3.3.1 Renewable Resources

The RESOLVE model was designed primarily to investigate investment driven by a renewable energy target. This constraint, which is applied based on the policy goal each year, ensures that the procured renewable energy net of any renewable energy curtailed in operations exceeds a MWh target based on the load or retail sales in that year. RESOLVE allows the user to specify a set of resources that must be built in each modeled year as well as additional renewable resources that may be selected by the optimization. These options allow for the design of portfolios that take into consideration factors such as environmental or institutional barriers to development.

While a traditional capacity-expansion model might take into consideration the technology cost, transmission cost, capacity factor of candidate renewable resources, RESOLVE also considers the energy value through avoided operational costs, capacity value through avoided resource adequacy build, and the integration value through avoided renewable resource overbuild. These three factors depend on the timing and variability of the renewable resource availability as well as the operational capabilities of the rest of the system. To account for all of these factors, each candidate resource is characterized by its hourly capacity factor over the subset of modeled days, installed cost on a per kW basis, location within a set of transmission development zones, and maximum resource potential, in MW.

Transmission development zones are characterized by a threshold total renewable build, above which a $/MW-yr cost is applied to incremental renewable build to reflect the annualized cost of additional transmission build to support interconnecting renewables on to the high-voltage transmission system. Multiple renewable resources may be assigned to the same transmission development zone (for example some zones may have both solar and wind resources that can be developed) and the selection of resources within each zone will depend on their relative net cost and the combined impact of resource build on incurred transmission development costs.

2.3.3.2 Integration Solutions

RESOLVE is also given the option to invest in various renewables integration solutions such as different types of energy storage or gas resources. Renewable curtailment occurs when the system is not capable of accommodating all of the procured renewable energy in hourly operations. While there is no explicit cost penalty applied to the curtailment observed in the system dispatch, the implicit cost is the cost of overbuilding renewable resources to replace the curtailed energy and ensure compliance with the renewable energy target. This renewable overbuild cost is the primary renewable integration cost experienced by the system and may be reduced by investment in integration solutions.

2.3.3.3 Resource Portfolios in Secondary Zones

RESOLVE selects investment decisions only for the primary zone, in this case the ISO. The resource portfolios for the secondary zones, in this case the Northwest, Southwest and LADWP, must be designed to ensure resource adequacy and renewable policy compliance, and selected as a RESOLVE input. These decisions, which are exogenous from the planner's perspective in the primary (ISO) zone are also exogenous to the model. For each year of the simulation, each secondary zone is characterized by the hourly load, hourly renewable availability, hydro availability, and conventional resource stack. Because the model only selects investment decisions for the primary zone, the resource portfolios for the secondary zones must be designed to ensure resource adequacy and renewable policy compliance outside of RESOLVE. These decisions, which are exogenous from the planner's perspective in the primary zone are also exogenous to the model. For the SB 350 project, renewable resources were hand-selected selected for the California municipal utilities outside the ISO's balancing area to ensure compliance with a 50% RPS by 2030 for these regions.

2.3.4 SYSTEM OPERATIONAL CONSTRAINTS

2.3.4.1 General

RESOLVE requires that sufficient generation is dispatched to meet load in each hour in each modeled zone. In addition, dispatch in each zone is subject to a number of constraints related to the technical capabilities of the fleets of generators within the zone, which are described in detail below. In general, dispatch in each zone must satisfy

$$\sum_{i \in I_z} x_h^{it} + w_h^{zt} + \sum_{\omega \in Z} \sum_{j \in J_{z\omega}} (R_{jt}^{tot} r_h^j - q_h^{jt}) + \sum_{k \in K_z^{in}} f_h^{kt} - \sum_{k \in K_z^{out}} f_h^{kt}$$

$$+ x_h^{dzt} - x_h^{czt} + u_h^{zt} - o_h^{zt} = l_h^{zt}$$

where l_h^{zt} is the load in zone *z*, year *t*, and hour *h*; x_h^{it} is the generation from thermal resource *i*; I_z is the set of all thermal resources in zone *z*; R_{jt}^{tot} is the total installed capacity of renewable resource *j*; q_h^{jt} is the curtailment of renewable resource j; $J_{z\omega}$ is the set of all renewable resources located in zone *z* and contracted to zone ω; w_h^{zt} is hydro generation in zone *z*; x_h^{dzt} and x_h^{czt} are the energy discharged from energy storage and energy extracted from the grid to charge energy storage respectively; u_h^{zt} is the undergeneration and o_h^{zt} is other overgeneration in zone *z*; f_h^{kt} is the flow over line k, K_z^{in} and K_z^{out} are the sets of all transmission lines flowing into and out of zone *z*, respectively.

2.3.4.2 Reserve Requirements and Provision

RESOLVE requires upward and downward load following reserves to be held in each hour in order to ensure that the system has adequate flexibility to meet sub-hourly fluctuations and to accommodate forecast errors. In real systems, reserve requirements depend non-linearly on the composition of the renewable portfolio and the renewable output in each hour. To avoid additional computational complexity, RESOLVE requires the user to specify the hourly reserve requirements for each scenario. In the ISO example, the methodology described in NREL the Eastern Wind Integration and Transmission Study ("EWITS")[4] was used to derive hourly reserve requirements associated with today's renewable portfolio, a 33% RPS portfolio in 2020, and two potential 50% RPS portfolios in 2030 – one dominated by solar resources and one with a more diverse mix of solar, wind, and geothermal resources. For each scenario, the user selects which set of reserve requirements to use for 2020 and 2030 and the reserve requirements in each year are approximated via linear interpolation.

The user specifies whether each technology is capable of providing flexibility reserves, and the reserve provisions available from each technology are described above. Upward flexibility reserve violations are penalized at a very high cost to ensure adequate commitment of resources to meet upward

[4] National Renewable Energy Laboratory, "Eastern Wind Integration and Transmission Study," Revised February 2011. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf

flexibility challenges within the hour. However, downward reserve shortages are not penalized as operating violations. RESOLVE assumes that a portion of downward reserve needs – 50% in the cases analyzed for this study – can be managed via real-time curtailment of renewable resources. This behavior is approximated in RESOLVE through a parameterization of the sub-hourly imbalances similar to that implemented in E3's REFLEX model.[5] Sub-hourly curtailment in RESOLVE is a function of the reserve provisions held, as described in Hargreaves et al (2014). If the entire downward reserve requirement is held, then it is anticipated that the system will experience no additional renewable curtailment in real-time to manage sub-hourly imbalances. If the downward reserve requirement cannot be met, then the expected real-time curtailment can be approximated.

This formulation allows the dispatch model to directly trade-off between the cost of holding additional reserves (including the cost of committing additional units and operating these units at less efficient set points) against the cost of experiencing some amount of expected sub-hourly renewable curtailment by shorting the downward reserve provision. Just as with curtailment experienced on the hourly level, expected sub-hourly curtailment is not directly penalized in the objective function, but does result in additional cost to the system by requiring additional renewable overbuild for policy compliance.

In addition, RESOLVE allows the user to constrain the absolute amount of observed sub-hourly curtailment in each hour to reflect potential limits in the participation of renewable resources in real-time markets or real-time dispatch

[5] Hargreaves, J., E. Hart, R. Jones, A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions of Power Systems, Volume:PP, Issue: 99, September 2014, pp 1 – 10.

decisions. These limits are typically set as a fixed fraction of the available energy from curtailable renewable resources in each hour.

Finally, RESOLVE allows the user to apply a minimum constraint on the fraction of the downward reserve requirement held with conventional units. Specifying a limit on the ability of renewables to provide the necessary downward reserves ensures that that the model will carry a portion of the needed reserves on conventional resources such as hydro or thermal resources, or on energy storage resources. While full participation of renewable resources in real-time markets may be the lowest cost approach to managing downward flexibility challenges, a system operator may seek to keep some downward flexibility across the conventional fleet as a backstop in case the full response from renewable resources does not materialize in real-time.

2.3.4.3 Other requirements

Additional operational constraints are imposed based on specific system needs. For example, for this SB 350 project, additional constraints were designed for consistency with modeling efforts by the ISO for the California Long-Term Procurement Plan ("LTPP"). These include: a frequency response requirement of 775MW in each hour, half of which can met upward capability on hydro resources and the other half of which can be met with other dispatchable units on the system including renewables and energy storage resources.

2.3.4.4 Resource Adequacy

In addition to hourly operational constraints, RESOLVE enforces an annual resource adequacy constraint based on a parameterization of resource adequacy needs to maintain reliability. The parametrization was developed based on simulations of loss of load probability ("LOLP") in the ISO system under high-solar and diverse renewable portfolio scenarios and takes into account the expected load-carrying capability ("ELCC") of the renewable portfolio. The constraint requires that sufficient conventional capacity is available to meet net load plus a certain percentage above net load. In this study, the capacity adequacy constraint is not binding and does not cause procurement of conventional capacity.

2.3.5 OPERATIONAL CONSTRAINTS

2.3.5.1 Thermal Resources

For large systems such as the ISO's, in RESOLVE thermal resources are aggregated into homogenous fleet of units that share a common unit size, heat rate curve, minimum stable operating level, minimum up and down time, maximum ramp rate, and ability to provide reserves. In each hour, dispatch decisions are made for both the number of committed units and the aggregate set point of the committed units in the fleet. For sufficiently large systems, such as the ISO, commitment decisions are represented as continuous variables. For smaller systems, specific units may be modeled with integer commitment variables. For the continuous commitment problem, reserve requirements ensure differentiation between the committed capacity of each fleet and its aggregated set point. The ability of each fleet to provide upward reserves, $\overline{x}_h^{it}$, is:

$$x_h^{it} + \overline{x}_h^{it} \leq n_h^{it} x_{max}^i \quad \forall i, t, h$$

where n_h^{it} is the number of committed units and x_{max}^i is the unit size. Downward reserve provision is limited by:

$$x_h^{it} - \underline{x}_h^{it} \geq n_h^{it} x_{min}^i \quad \forall i, t, h$$

where x_{min}^i is the minimum stable level of each unit.

Upward reserve requirements are imposed as firm constraints to maintain reliable operations, but downward reserve shortages may be experienced by the system with implications for renewable curtailment (See section 2.3.4.2). The primary impact of holding generators at set points that accommodate reserve provisions is the increased fuel burn associated with operating at less efficient set points. This impact is approximated in RESOLVE through a linear fuel burn function that depends on both the number of committed units and the aggregate set point of the fleet:

$$g_h^{it} = e_i^1 x_h^{it} + e_i^0 n_h^{it}$$

where g_h^{it} is the fuel burn and e_i^1 and e_i^0 are technology-specific parameters.

Minimum up and down time constraints are approximated for fleets of resources in RESOLVE. In addition, startup and shutdown costs are incurred as the number of committed units change from hour to hour, and constraints to approximate minimum up and down times for thermal generator types are imposed.

Must-run resources are modeled with flat hourly output based on the installed capacity and a de-rate factor applied to each modeled day based on user-defined maintenance schedules. Maintenance schedules for must-run units are designed to overlap with periods of the highest anticipated oversupply conditions so that must run resources may avoid further exacerbating oversupply conditions in these times of year. Maintenance and forced outages may be treated for any fleet through the daily de-rate factor. However, in the analysis presented here, maintenance schedules for dispatchable resources were not explicitly modeled – it was instead assumed that maintenance on these systems could be scheduled around the utilization patterns identified by RESOLVE's dispatch solution.

2.3.5.2 Hydroelectric Resources

Hydroelectric resources are dispatched in the model at no variable cost, subject to: an equality constraint on the daily hydro energy; daily minimum and maximum outputs constraints; and multi-hour ramping constraints. These constraints are intended to reflect seasonal environmental and other constraints placed on the hydro system that are unrelated to power generation. The daily energy, minimum, and maximum constraints are derived from historical data from the specific modeled days. Ramping constraints, if imposed, can be derived based on a percentile of ramping events observed over a long historical record. Hydro resources may contribute to both upward and downward flexibility reserve requirements.

2.3.5.3 Energy Storage

Each storage technology is characterized by a round-trip efficiency, per unit discharging capacity cost ($/kW), per unit energy storage reservoir or maximum state of charge cost ($/kWh), and for some resources, maximum available capacity. Energy storage investment decisions are made separately for discharging capacity and reservoir capacity or maximum state of charge. Dispatch from each energy storage resource is modeled by explicitly tracking the hourly charging rate, discharging rate, and state-of-charge of energy storage systems based on technology-specific parameters and constraints. Reserves can be provided from storage devices over the full range of maximum charging to maximum discharging. This assumption is consistent with the capabilities of battery systems, but overstates the flexibility of pumped storage systems, which can only provide reserves in pumping mode if variable speed pumps are installed, typically pump storage units cannot switch between pumping and generating on the time scales required for reserve products, and are subject to minimum pumping and minimum generating constraints that effectively impose a deadband on the resource operational range.

An adjustment to the state of charge in RESOLVE is assumed that represents the cumulative impact of providing flexibility reserves with the device over the course of the hour. For example, if a storage device provides upward reserves throughout the hour, it is anticipated that over the course of the hour the storage device will be called upon to increase its discharge rate and/or decrease its charge rate to help balance the grid. These sub-hourly dispatch adjustments will decrease the state of charge at the end of the hour. Similarly, providing downward reserves will lead to an increase in the state of charge at the end of

the hour. Little is known about how energy storage resources will be dispatched on sub-hourly timescales in highly renewable systems – this behavior will depend on storage device bidding strategies and technical considerations like degradation. Rather than model these factors explicitly, RESOLVE approximates the impact of sub-hourly dispatch with a tuning parameter, which represents the average deviation from hourly schedules experienced as a fraction of the energy storage reserve provision.

3 SB 350 Study Assumptions

3.1 Scenario Definitions and Assumptions

Using the RESOLVE model described above, E3 developed renewable portfolios for three scenarios in California. Each of the scenarios meets a 50% renewables portfolio standard ("RPS") in 2030. The scenarios are:

+ **Current Practice 1 Scenario: Current practice:** This scenario assumes that renewable energy procurement is largely from in-state resources, with 5,000 MW of out-of-state resources available over existing transmission. This scenario does not assume an expanded regional market.
+ **Regional 2 Scenario: Regional market operations with "current practice" renewable energy procurement policies:** This scenario assumes expanded regional markets, but assumes no change to current renewable energy procurement policies, i.e., procurement policies continue to favor in-state resources even when out-of-state resources are lower cost.
+ **Regional 3 Scenario: Regional market operations with regional procurement:** This scenario assumes expanded regional markets, as well as regional procurement of out-of-state resources over new transmission.

3.2 Load Forecast

The ISO load forecast is based on the 2015 IEPR Mid AAEE load forecast (January 2016 Update)[6]. 2026-2030 data (not in IEPR) is extrapolated using the 2024-2026 average annual growth rate. The IEPR forecast includes estimates for energy efficiency, electric vehicles, and behind-the-meter solar, among others (see below).

Table 9. 2015 IEPR Mid Baseline Mid AAEE Forecast for ISO

Metric (all units in GWh/yr)	2015	2020	2025	2030
Mid Baseline Demand Before Any Modifiers	**309,930**	**328,805**	**343,450**	**360,166**
Demand Adders	**481**	**2,344**	**6,299**	**12,280**
Electric Vehicles	481	1,785	4,954	9,910
Other Electrification	-	311	849	1,553
Climate Change Impacts	-	248	497	818
Demand Reducers	**92,511**	**118,954**	**140,076**	**170,485**
Self-Generation Photovoltaic*	5,297	10,139	16,964	28,465
Self-Generation Other Private Generation	11,934	13,528	13,962	14,281
AAEE Savings	137	8,838	16,600	26,208
Committed EE Savings	75,143	86,449	92,550	101,530
2015 IEPR Managed Sales (retail)	**217,900**	**212,195**	**209,673**	**201,961**
2015 IEPR Managed Net Energy for Load**	**235,011**	**228,748**	**225,877**	**217,302**

* De-rated by 2% to account for losses incurred when exporting customer PV (different from IEPR forecast which assumes no losses). The equivalent installed capacity in 2030 is 16,649 MW (ac)

** Grossed up for losses at 7.33%.

[6] Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

3.2.1 HOURLY LOAD SHAPES

Load shapes for the ISO zone were built up from end use-specific hourly shapes. Hourly load shapes for non-transportation ISO loads are based on historical data. These non-transportation ISO loads are then adjusted to account for the impact of implementing mandatory residential time-of-use rates by 2020. Furthermore, the impact of smart charging and day-time charging availability of light-duty electric vehicles ("EV") is reflected in an EV load shape that is added onto the adjusted non-transportation load shape.

Load shapes in other zones, including non-ISO California entities, are based on the TEPPC 2024 Common Case, with fixed annual load growth rates extrapolated to 2030.

3.2.1.1 Time-of-use rates and flexible loads

The effect of time-of-use rates is implemented as a fixed 24-hour load shape adjustment for every month. The load shape adjustment for January is shown in the table below; other months show essentially the same load shape adjustment. By 2030, we assume there is up to about 1,000 MW of load shifting, from the evening hours into the early morning and midday hours. Aside from this time-of-use rate adjustment, demand response and other flexible loads are not explicitly modeled in this iteration of the analysis.

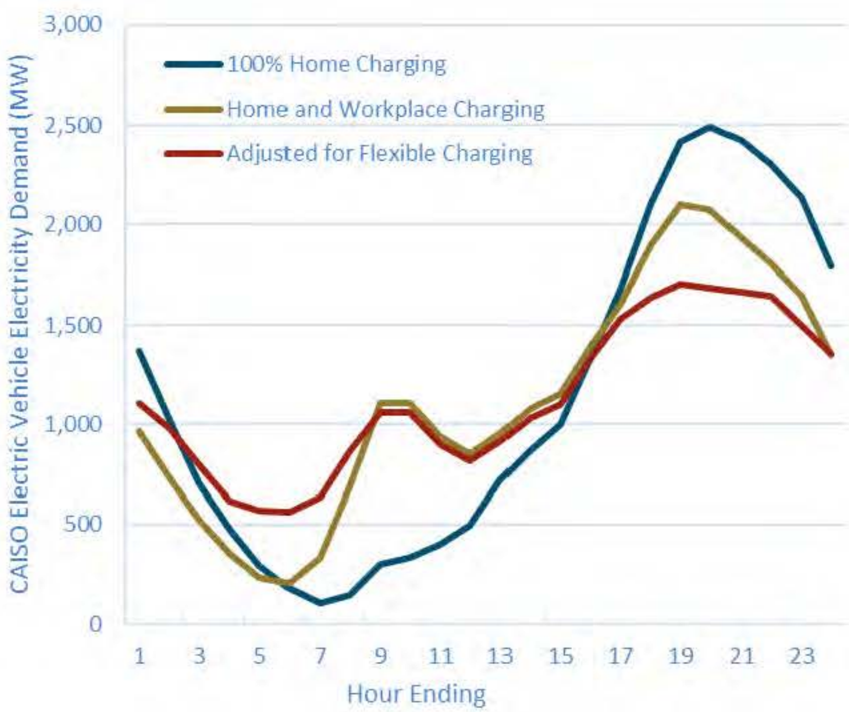
Table 10. Hourly load shape adjustment (MW) due to time-of-use rates in ISO in the month of January for the years 2015, 2020, 2025 and 2030.

Hour	2015	2020	2025	2030
1	0	319	321	264
2	0	319	321	264
3	0	319	321	264
4	0	319	321	264
5	0	319	321	264
6	0	319	321	264
7	0	319	321	264
8	0	418	435	410
9	0	517	549	556
10	0	616	663	701
11	0	715	777	847
12	0	813	891	992
13	0	715	777	992
14	0	616	663	847
15	0	287	305	437
16	0	-42	-53	27
17	0	-371	-412	-383
18	0	-601	-656	-793
19	0	-831	-900	-1057
20	0	-831	-900	-1057
21	0	-831	-900	-1057
22	0	-831	-900	-1057
23	0	-831	-900	-1057
24	0	-601	-656	-1057

3.2.1.2 Electric Vehicle Load Profiles

EV load profiles are created using an EV charging model developed by E3, which modify the base load profile assumptions. The charging model is based on the 2009 National Household Transportation Survey ("NHTS"), a dataset on personal travel behavior. The model translates travel behavior into aggregate EV load shapes by weekday/weekend-day, charging strategy, and charging location availability. The weekend/weekday shapes are aggregated and normalized into month hour shapes by charging location availability. A blend is created by assuming 20% of drivers have charging infrastructure only available at home, while 80% of drivers have charging infrastructure available both at home and at the workplace. Last, the evening peak of this blended shape is shifted partly to the early morning hours to reflect smart charging. To obtain the actual load profile, the normalized profile is multiplied with the annual EV load. The resulting ISO EV Load shape for January 2030 is shown below.

Figure 2. ISO Electric Vehicle charging Profile (January 2030 example)



3.3 Renewable Generation Shapes

Hourly shapes for wind resources were obtained from NREL's Wind Integration National Dataset ("WIND") Toolkit[7] and adjusted using a filter in order to match the site-specific capacity factors in the CPUC's RPS Calculator (version 6.1)[8]. Hourly solar shapes were obtained using NREL's Solar Prospector[9] and scaled/filtered to match capacity factors in the CPUC's RPS Calculator (version 6.1).

3.4 Thermal Resources

The thermal resource stack in the ISO footprint is characterized based on the 2014 Long Term Procurement Plan modeling undertaken by the ISO and adjusted to reflect retirements that are scheduled to occur between after 2015. Thermal resources are grouped by technology and performance characteristics (heat rate, minimum stable level, and ramp rate) into fleets of similarly behaving resources which RESOLVE treats as homogenous. The resulting thermal fleets are summarized in Table 2. Outside of ISO, thermal fleets are developed for each region based on the 2024 TEPPC Common Case. Coal retirements planned for between 2024 and 2030 are also reflected in each resource stack, assuming a one-for-one replacement with combined cycle gas units. A coarser aggregation approach is applied to non-ISO regions in order to reduce

[7] The Wind Toolkit and associated materials can be obtained from NREL at: http://www.nrel.gov/electricity/transmission/wind_toolkit.html
[8] The RPS Calculator and associated materials can be obtained from the CPUC at: http://www.cpuc.ca.gov/RPS_Calculator/
[9] The Solar Prospector and associated materials can be obtained from NREL at: http://maps.nrel.gov/node/10

computational complexity. The conventional resource installed capacities by year are listed in Table 11.

Table 11. Performance characteristics for planned (i.e. exogenously selected) resources in each zone

Planned Resources	Pmax (MW)	Pmin (MW)	Max Ramp (%Pmax/hr)	Min Up/Down Time (hrs)	Startup Cost ($/MW)	Fuel Burn Slope (MMBtu/MWh)	Fuel Burn Intercept (MMBtu/unit)
ISO Resources							
CHP	39 3	39.2	0%	24	0.0	6.845	0
Nuclear	572	572	0%	24	0.0	9.576	0
CCGT1	393	175	100%	6	50.9	6.268	288
CCGT2	410	118	100%	6	48.8	6.050	427
Gas Peaker1	64.4	28.0	100%	1	77.6	8.262	74
Gas Peaker2	44 9	16.3	100%	1	111.5	7.577	122
Steam Turbine	358	28.7	100%	6	10.0	9.302	212
Demand Response	1	0	100%	0	0	0	0
Northwest Resources							
Nuclear	1,170	995	0%	24	-	10.907	-
Coal	344	137	100%	24	14.54	9.222	283
CCGT	337	166	100%	6	14.83	6.614	219
Gas Peaker	30	11	100%	1	662.71	9.381	39
Southwest Resources							
Nuclear	953	953	0%	24	-	10.544	-
Coal	427	171	100%	24	11.70	9.151	354
CCGT	391	199	100%	6	12.77	6.619	315
Gas Peaker	71	25	100%	1	279.97	8.795	141
LADWP Resources							
Nuclear	152	152	0%	24	-	10.544	-
Coal	820	328	100%	24	6.10	8.656	644
CCGT	230	123	100%	6	22	6.967	65
Gas Peaker	79.1	36	100%	1	253	8.857	88

Table 12. Installed capacities of planned (i.e. exogenously selected) resources in each zone across all scenarios

Resource	Planned Installed Capacity (MW)			
	2015	2020	2025	2030
ISO Resources				
CHP	4,006	4,006	4,006	4,006
Nuclear	2,862	2,862	1,742	622
CCGT1	10,705	9,307	10,207	10,207
CCGT2	5,328	5,328	5,328	5,328
Gas Peaker1	3,471	3,471	3,671	3,671
Gas Peaker2	3,200	3,046	2,916	2,916
Steam Turbine	10,388	6,314	0	0
Demand Response	2,088	2,169	2,179	2,179
Northwest Resources				
Nuclear	1,170	1,170	1,170	1,170
Coal	12,784	10,962	9,665	7,970
CCGT	12,034	14,296	15,593	17,288
Gas Peaker	4,193	4,135	4,135	4,050
Southwest Resources				
Nuclear	2,858	2,858	2,858	2,858
Coal	12,391	10,080	9,241	9,241
CCGT	21,130	23,445	24,169	24,169
Gas Peaker	8,885	11,329	12,903	12,528
LADWP Resources				
Nuclear	457	457	457	457
Coal	1,640	1,640	0	0
CCGT	2,069	2,069	3,709	3,709
Gas Peaker	2,742	2,769	2,531	2,531

3.5 ISO Base Portfolio (33% RPS)

The model starts from a ISO base portfolio that meets 33% RPS in 2030. This portfolio is based on contracted resources in the CPUC's RPS Calculator (version 6.1) and consists mostly of currently existing renewable resources. All results shown in the results section of this report are additional to this "existing" base portfolio, and lift the total amount of RPS renewable energy from 33% to 50%.

Table 13. ISO Base Portfolio: Renewables to meet 33% RPS in the ISO balancing area in 2030.

Renewable Resources	Installed Capacity (MW)	Annual Energy (GWh)
ISO Solar	9,890	18,259
ISO Wind	5,259	15,859
ISO Geothermal	1,117	9,785
ISO Small Hydro	429	3754
ISO Biomass	794	6955
Northwest Wind	2,186	6,073
Northwest Biomass	32	280
Northwest Geothermal	1	6
Southwest Solar	197	380
Imperial Geothermal	449	3933
Total ISO Resources	**17,489**	**54,612**
Total Non-ISO Resources	**2,417**	**10,672**
Total Renewable Resources	**20,354**	**65,284**
Other Resources	**Installed Capacity (MW)**	**Annual Energy (GWh)**
Energy Storage	3,157	-
Behind-the-meter Rooftop PV	16,649	29,046

3.6 In-State Renewable Potential

The California renewable potential considered in RESOLVE is based on the CPUC's RPS Calculator (version 6.1) with several modifications:

+ The RPS Calculator's granular resource potential data has been aggregated to eleven California resource zones, each of which consists of one or more Competitive Renewable Energy Zones (CREZs), shown in Figure 3; and
+ The potential resources available in each zone have been limited based on discussions with the Aspen Environmental Group, which identified environmental constraints that may make development in specific areas challenging.

Because of these modifications to the RPS Calculator's resource potential assumptions, the "potential" considered in RESOLVE does not reflect the maximum technical potential for each resource available in California, but rather is intended to reflect a reasonable upper limit for development in each zone that accounts for environmental, political, and transmission-related factors.

The renewable potential assumed in each of these resource zones, which is considered available in all scenarios, is summarized in Table 14.

Figure 3. California resource zones included in RESOLVE model

Table 14. California renewable potential considered in RESOLVE (additional to existing renewables)

Resource	Zone	Potential (MW)
Geothermal	Greater Imperial	1,384
	Northern California	424
	Subtotal	***1,808***
Solar PV	Central Valley & Los Banos	1,000
	Greater Carrizo	570
	Greater Imperial	1,317
	Kramer & Inyokern	375
	Mountain Pass & El Dorado	-
	Northern California	1,702
	Riverside East & Palm Springs	2,459
	Solano	551
	Southern California Desert	-
	Tehachapi	2,500
	Westlands	1,450
	Subtotal	**11,924**
Wind	Central Valley & Los Banos	150
	Greater Carrizo	500
	Greater Imperial	400
	Riverside East & Palm Springs	500
	Solano	600
	Tehachapi	850
	Subtotal	***3,000***
Total California Renewable Potential		**16,732**

3.7 Out-of-State Renewable Potential

In Current Practice 1 and Regional 2, the renewable portfolios to meet California's RPS mandates are constrained to include only out-of-state resources that can be delivered on the existing system without requiring major new transmission; resources that would require major new interregional transmission projects are excluded. In Regional 3, the portfolio considers both projects that can be delivered through existing transmission as well as those that would require major new transmission investment. The transmission costs associated with each of these resources are discussed in Section 3.9.

Table 15. Out-of-state resource potential included in RESOLVE.

Resource		Description	Potential (MW)		
			Current Practice 1	Regional 2	Regional 3
Arizona Solar PV		High quality solar PV resource, available for delivery on existing transmission system	1,500	1,500	1,500
New Mexico Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	1,000	1,000	1,000
Oregon Wind		Low quality wind resource, available for delivery on existing transmission system	2,000	2,000	2,000
Wyoming Wind	1	Highest quality wind resource, requires new transmission investment	-	-	1,500
	2	Medium quality wind resource, requires new transmission investment	-	-	1,500
	3	Lowest quality wind resource, available for delivery on existing transmission system	500	500	500
Total Out-of-State Resources Available			**5,000**	**5,000**	**11,000**

3.8 Renewable Cost & Performance

Renewable resource cost and performance for the resources identified in Sections 3.3 and 3.7 are derived from the CPUC's RPS Calculator (version 6.1), with adjustments made to solar and geothermal costs based on stakeholder feedback as part of the SB 350 study process. The RPS Calculator's assumptions regarding cost and performance for new renewables have been modified—in most cases, reduced—for this study based on stakeholder feedback and a review of current literature, including:

+ *2014 Wind Technologies Market Report* (US DOE);[10]
+ *Utility Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (LBNL);[11]
+ WREZ Generation and Transmission model (version 2.5);[12] and
+ Email correspondence with the Geothermal Energy Association.

The cost and performance of all candidate renewables for the portfolios—both in California and in the rest of the WECC—are summarized in Table 16. The federal renewable investment tax credit ("ITC") and production tax credit ("PTC") are both assumed to be reduced by 2030 according to current federal policy. The Federal PTC and ITC phase out by 2019 for wind and by 2021 for solar and geothermal. Solar PV and geothermal remain eligible for a 10% ITC after 2021.

Learning rates are assumed to reduce the capital cost of renewable technologies over time. However, the scheduled roll-offs of the federal PTC and ITC can result in a higher levelized cost of energy ("LCOE") in 2030 compared to today.

[10] Available at: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf

[11] Available at: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf

[12] Available at: http://www.westgov.org/component/docman/doc_download/1475-wrez-generation-and-transmission-model-

Table 16. Renewable resource cost & performance assumptions in RESOLVE.

Resource	Geography		Capacity Factor (%)	Capital Cost (2015 $/kW)		LCOE (2015 $/MWh)	
				2015	2030	2015	2030
California Geothermal	Imperial		90%	$ 5,142	$ 5,142	$ 76	$ 96
	Northern California		80%	$ 3,510	$ 3,510	$ 59	$ 81
California Solar PV	Central Valley & Los Banos		30%	$ 2,174	$ 1,826	$ 58	$ 76
	Greater Carrizo		33%	$ 2,174	$ 1,826	$ 53	$ 69
	Greater Imperial		31%	$ 2,174	$ 1,826	$ 56	$ 73
	Kramer & Inyokern		34%	$ 2,174	$ 1,826	$ 50	$ 66
	Mountain Pass & El Dorado		34%	$ 2,174	$ 1,826	$ 50	$ 65
	Northern California		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Riverside East & Palm Springs		32%	$ 2,174	$ 1,826	$ 53	$ 70
	Solano		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Southern California Desert		34%	$ 2,174	$ 1,826	$ 51	$ 67
	Tehachapi		33%	$ 2,174	$ 1,826	$ 52	$ 68
	Westlands		31%	$ 2,174	$ 1,826	$ 55	$ 72
OOS Solar PV	Arizona		34%	$ 2,001	$ 1,711	$ 45	$ 56
California Wind	Central Valley & Los Banos		30%	$ 2,069	$ 2,008	$ 51	$ 76
	Greater Carrizo		31%	$ 1,914	$ 1,857	$ 49	$ 74
	Greater Imperial		35%	$ 2,083	$ 2,022	$ 43	$ 68
	Riverside East & Palm Springs		33%	$ 2,047	$ 1,987	$ 57	$ 82
	Solano		27%	$ 1,992	$ 1,933	$ 58	$ 82
	Tehachapi		35%	$ 2,087	$ 2,025	$ 47	$ 72
OOS Wind	New Mexico	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55
	Oregon		32%	$ 1,943	$ 1,885	$ 49	$ 74
	Wyoming	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55

* OOS = out-of-state, LCOE = levelized cost of energy . Solar capital cost is expressed with respect to AC capacity with assumed inverter loading ratio of 1.3; i.e. the cost per kW-AC is 1.3 times higher than the cost per kW-DC.

3.9 Transmission Availability & Cost

3.9.1 CALIFORNIA RESOURCES

For each resource zone in California, the ability to connect resources to the existing system is limited; assumptions are based on the rules of thumb developed by ISO for its 50 % Renewable Energy Special Study conducted as part of the 2015-2016 Transmission Planning process.[13] To the extent that the available resource potential in a zone exceeds the limits of the existing system, a transmission cost penalty is included for incremental additions beyond these limits; the assumed transmission cost is based on the assumptions of the RPS Calculator. This two-tiered approach for applying transmission costs to new resources is shown illustratively in Figure 4, where 'Available Capacity (a)' represents the limit of a system to accommodate new renewables at no cost; and 'Incremental Cost (b)' reflects the cost of new transmission upgrades once the available capacity has been exhausted. The assumptions for each of these parameters for each resource zone in California are summarized in Table 17.

[13] Available at: https://www.ISO.com/Documents/Draft2015-2016TransmissionPlan.pdf

Figure 4. Illustrative transmission costing for a California resource zone in RESOLVE

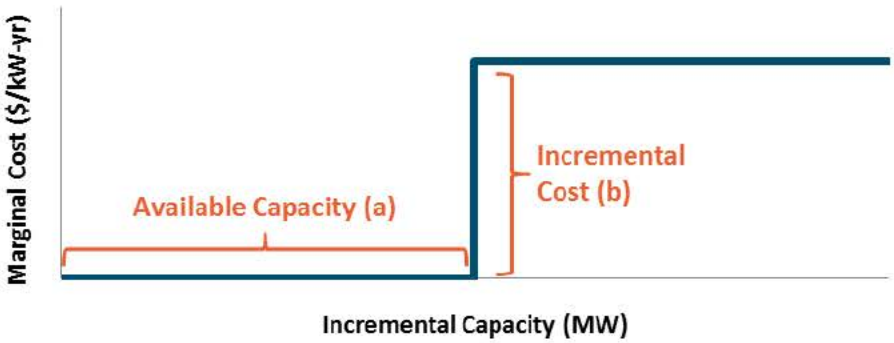


Table 17. Availability of energy only capacity and cost of transmission upgrades in California zones.

Zone	Capacity Available at no cost (MW)	Cost for Incremental Capacity ($/kW-yr.)
Central Valley & Los Banos	2,000	$ 29
Greater Carrizo	1,140	$ 114
Greater Imperial	2,633	$ 68
Kramer & Inyokern	750	$ 52
Mountain Pass & El Dorado	2,982	$ 65
Northern California	3,404	$ 95
Riverside East & Palm Springs	4,917	$ 85
Solano	1,101	$ 13
Southern California Desert	-	$ 64
Tehachapi	5,000	$ 21
Westlands	2,900	$ 58

3.9.2 OUT-OF-STATE RESOURCES

The transmission needs associated with out-of-state resources vary depending both on the resource and the scenario, but generally reflect one of two types of costs:

- Wheeling and pancake losses resulting from the need to purchase firm service on the existing transmission system from one or more neighboring balancing authorities; or
- Costs associated with major new projects to deliver a renewable resource to a sufficiently liquid trading hub.

The application of these costs to out-of-state resources varies by scenario:

- In Current Practice 1, only resources that can be delivered on the existing system are considered; the cost of wheeling through neighboring balancing areas is attributed to these resources. Current Practice 1 does not include resources that would require major new interregional transmission infrastructure to be constructed.
- Regional 2 considers the same set of resources as Current Practice 1; however, the shift towards a regional market results in no direct wheeling costs for the entities within the Regional ISO.
- Regional 3 considers both resources that can be delivered on the existing system as well as those that would require major new transmission. Resources that can be delivered on the existing system incur no transmission costs. Resources that require transmission upgrades are assumed to pay the annual revenue requirement associated those upgrades.

The differential treatment of transmission costs in each scenario—as well as the basis used to estimate each resource's associated transmission costs—are summarized in Table 18.

Table 18. Transmission cost assumptions for out-of-state resources

Resource		Quantity (MW)	Costs ($/kW-year)			Basis for Assumption
			CP 1	Reg. 2	Reg. 3	
Southwest Solar PV		1500	$39	$0	$0	Wheeling & losses on APS system
New Mexico Wind	1	1500	N/A	N/A	$50	Assumed project capital cost ($567 million for 1,500 MW of new transmission) based on RPS Calculator transmission costs, scaled for distance for delivery to Four Corners
	2	1500	N/A	N/A	$129	Sum of public information regarding SunZia costs ($2 billion for 3,000 MW) and assumed upgrade costs from Pinal Central to Palo Verde based on RPS Calculator
	3	1000	$72	$0	$0	Wheeling & losses on PNM & APS systems
Northwest Wind		2000	$34	$0	$0	Wheeling & losses on BPA system (system + southern intertie rates)
Wyoming Wind	1 & 2	3000	N/A	N/A	$88	Costs of Gateway project reported ($252 million per year for 2,875 MW) reported in *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration* (Technical Appendix)
	3	500	$66	$0	$0	Wheeling & losses on PacifiCorp East & NV Energy systems

3.10 Storage Resources

Energy storage cost and performance inputs are based on a review of the literature and projections from manufacturers and developers, including:

+ *Lazard's Levelized Cost of Storage Analysis – version 1.0* (Lazard, 2015);[14]
+ *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA* (Sandia National Laboratories, 2013);[15]
+ *Electrical energy storage systems: A comparative life cycle cost analysis* (Zakery and Syri, Renewable and Sustainable Energy Reviews 2015);[16]
+ *Rapidly falling costs of battery packs and electric vehicles* (Nykvist and Nilsson, Nature Climate Change 2015);[17]
+ *2015 Greentechmedia.com coverage on emerging battery manufacturers*
+ *Tesla Powerwall webpage (Last visited March 2016);*[18]
+ *Capital Cost Review of Power Generation Technologies; Recommendations for WECC's 10- and 20-year studies (E3, 2014); only used for pumped hydro*[19]

[14] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf
[15] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf
[16] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284
[17] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html
[18] Available at: https://www.teslamotors.com/powerwall
[19] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool. For lithium ion and flow batteries, a 15% adder is added on top of the capital costs shown in Table 20 to take into account engineering, procurement and construction ("EPC"), and interconnection. E3 modeled replacement of the lithium ion battery pack in year 8 and replacement of the flow battery and lithium ion battery power conversion system in year 10. Replacement costs are assumed to be equal to the capital costs of the replacement item in the year of replacement (not including the 15% adder).

Cost and performance assumptions for energy storage technologies are summarized in the tables below.

Table 19. Energy storage performance and resource potential by technology.

Technology	Charging & Discharging Efficiency	Financing Lifetime (yr)	Replace-ment (yr)	Minimum duration (hrs)	Resource Potential (MW)
Lithium Ion Battery	92%	16	8	0	N/A
Flow Battery	84%	20	N/A	0	N/A
Pumped Hydro	87%	40	N/A	12	4,000

Note: For Lithium Ion Batteries and Flow Batteries we also assume inverter replacement at year 10.

Table 20. Energy storage cost assumptions by technology.

Type	Cost Metric	2015	2030
Lithium Ion Battery	Storage Cost ($/kWh)	$375	$183
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$7.5	$3.7
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Flow Battery	Storage Cost ($/kWh)	$700	$315
	Power Conversion System Cost ($/kW)	$300	$204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	$14.0	$6.3
	Fixed O&M PCS ($/kW-yr)	$6.0	$4.1
Pumped Hydro	Storage Cost ($/kWh)	$117	$117
	Power Conversion System Cost ($/kW)	$1,400	$1,400
	Fixed O&M Battery/Reservoir ($/kWh-yr)	-	-
	Fixed O&M PCS ($/kW-yr)	$15	$15

Table 21. Energy storage cost estimates in 2015 and 2030 for each technology ($/kW-yr and $/KWh-yr).

Technology	2015 Annualized Cost Components ($/kW-yr; $/kWh-yr)	2030 Annualized Cost Components ($/kW-yr; $/kWh-yr)
Lithium Ion Battery	$69; $85	$46; $40
Flow Battery	$58; $118	$39; $53
Pumped Hydro	$146; $12	$146; $12

Note: The first number indicates the annualized cost of the power conversion system ($/kW-yr) of the device and the second number indicates the annualized cost of the energy storage capacity or reservoir size ($/kWh-yr). Both numbers are additive. This annualized cost is the full cost of owning and operating the system, including O&M and replacement costs

3.11 Conservative nature of study assumptions

When considering appropriate assumptions for the base case, E3 has tried as a general to make assumptions that are conservative, i.e., that tend to understate the potential benefits of a regional market. While not every individual assumption is conservative, we believe that the assumptions as a whole result in a conservative estimate of the benefits of a regional market. Most importantly, we have assumed that a number of renewable integration solutions are in place by 2030, despite the fact that each solution is significantly more costly than a regional market (which returns positive net benefits even before renewable integration is considered). Conservative assumptions include:

- The study assumes that time-of-use retail electricity rates are in place that encourage daytime use, shifting 1000 MW of load into daylight hours with overgeneration.

- The study assumes that 5 million electric vehicles are in service by 2030, with near-universal access to workplace charging. A significant proportion of the charging occurs during daylight hours with overgeneration.

- The study assumes that 500 MW of pumped storage are added to the portfolio in all scenarios, despite the fact that this resource is not cost-effective using study assumptions. This significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that 500 MW of geothermal are added to the portfolio in all scenarios, displacing approximately 1500 MW of wind or solar resources that would otherwise have been needed. This significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that 5,000 MW of out-of-state renewable resources, delivered over existing transmission, are available to be selected on a least-cost basis. This provides diversity to the portfolio and significantly reduces the renewable integration burden under Current Practice 1.

- The study assumes that a regional market makes available only 6000 MW of out of state resources. In reality, a truly regional market could unlock vast quantities of renewable resource potential from across the interconnection.

- The study assumes that unlimited bulk energy storage is available to be selected on a least-cost basis, with very aggressive cost reduction trajectories.

- The study assumes that renewables are allowed to provide downward operating reserves across all scenarios. This significantly reduces the quantity of thermal generation that runs during overgeneration hours, and therefore the quantity of renewable curtailment that could be avoided with a regional market.

- The study assumes that storage and hydro provide operating reserves and frequency response, significantly reducing the quantity of thermal generation that runs during overgeneration hours and therefore the quantity of renewable curtailment that could be avoided with a regional market.

- The study uses a simplified representation of the thermal portfolio and imports, understating the extent to which thermal generation inflexibility could exacerbate renewable overgeneration.

- The study assumes that energy-only resources are the dominant form of contract in future renewable procurement, eliminating the need for any new transmission in California to meet the 50% RPS under the Current Practice 1 scenario.

- The study does not fully account for improved regional optimization of hydro resources, which could be called upon to perform renewable integration services under a regional market, reducing curtailment and the necessary renewable overbuild in the Regional 2 and Regional 3 scenarios.

4 Renewable Portfolio Results

4.1 Summary of key findings

Regional markets result in significantly lower renewable procurement costs for California across all scenarios and sensitivities.

- Renewable procurement cost savings are **$680 million/year** in 2030 under regional markets with current practices in renewable procurement
- Procurement cost savings are **$799 million/year** in 2030 under regional markets with regional renewable procurement
- Savings range is **$391-$1,341 million/year** in 2030 under regional markets, across all sensitivities. The largest savings occur under the 55% RPS sensitivity, which is roughly consistent with the commitment PG&E made in the recent Diablo Canyon retirement settlement.

Table 22. Summary of 2030 renewable procurement cost savings offered by a regional market.

Renewable portfolio cost savings from regional market ($MM/year)		Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case		$680	$799
A.	**High coordination under bilateral markets**	$391	$511
B.	**High energy efficiency**	$576	$692
C.	**High flexible loads**	$495	$616
D.	**Low portfolio diversity**	$895	$1,004
E.	**High rooftop PV**	$838	$944
F.	**High out-of-state resource availability**	$578	$661
G.	**55% RPS**	$1,164	$1,341
H.	**Low cost solar**	$510	$647

4.2 Renewable portfolios

RESOLVE is used to obtain the optimal renewable portfolios for the ISO balancing area in each scenario. For the non-ISO balancing areas ("Munis"), the 2030 renewable portfolios are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario, which is informed by historical procurement decisions as well as the optimal portfolios RESOLVE selected for the ISO.

The tables below show the renewable portfolios to go from 33% RPS to 50% RPS in 2030 for the ISO, the Munis, and California statewide.

Table 23. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	5,226	5,429	2,136
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	115	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**8,726**	**7,829**	**4,536**
Total Out-of-State Resources	**4,500**	**4,115**	**6,000**
Total Renewable Resources	**13,226**	**11,944**	**10,536**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 24. 2030 ISO cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	14,890	15,555	6,211
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	2,803	321	-
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	6,044
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	6,044
Total CA Resources	**27,312**	**25,093**	**15,749**
Total Out-of-State Resources	**13,708**	**12,715**	**21,679**
Total Renewable Resources	**41,020**	**37,808**	**37,428**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 25. 2030 ISO out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-50% Portfolio	33%	34%	58%
Out of State Share in total Portfolio	23%	23%	31%

Table 26. 2030 Munis cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	2,375	2,375	1,304
California Wind	-	-	-
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	447	447	318
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	-	-	-
Wyoming Wind, New Transmission	-	-	495
Southwest Solar, Existing Transmission	-	-	-
Southwest Solar RECs	-	-	-
New Mexico Wind, Existing Transmission	-	-	-
New Mexico Wind, New Transmission	-	-	462
Total CA Resources	**2,375**	**2,375**	**1,304**
Total Out-of-State Resources	**1,051**	**1,051**	**1,694**
Total Renewable Resources	**3,426**	**3,426**	**2,998**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 27. 2030 Munis cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	6,592	6,592	3,616
California Wind	-	-	-
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	1,253	1,253	891
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	-	-	-
Wyoming Wind, New Transmission	-	-	1,993
Southwest Solar, Existing Transmission	-	-	-
Southwest Solar RECs	-	-	-
New Mexico Wind, Existing Transmission	-	-	-
New Mexico Wind, New Transmission	-	-	1,861
Total CA Resources	6,592	6,592	3,616
Total Out-of-State Resources	2,946	2,946	5,922
Total Renewable Resources	9,538	9,538	9,538
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 28. 2030 Munis out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-50% Portfolio	31%	31%	62%
Out of State Share in total Portfolio (estimate)	29%	29%	39%

The 33% Muni portfolio is not explicitly modeled. E3 estimates the 33% portfolio consists of 13,442 GWh in-state renewables and 5,073 GWh out-of-state renewables

Table 29. 2030 Statewide cumulative renewable portfolio additions in MW of installed capacity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,601	7,804	3,440
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,447	562	318
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	604	604	420
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,995
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,962
Total CA Resources	11,101	10,204	5,840
Total Out-of-State Resources	5,551	5,166	7,694
Total Renewable Resources	**16,652**	**15,370**	**13,534**
Batteries	472	-	-
Pumped Hydro	500	500	500

Table 30. 2030 Statewide cumulative renewable portfolio additions in GWh of 2030 annual generation.

New Resources (GWh)	Current Practice 1	Regional 2	Regional 3
California Solar	21,482	22,147	9,827
California Wind	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,574	891
Northwest Wind RECs	2,803	2,803	-
Utah Wind, Existing Transmission	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708
Wyoming Wind, New Transmission	-	-	8,037
Southwest Solar, Existing Transmission	-	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416
New Mexico Wind, New Transmission	-	-	7,905
Total CA Resources	33,904	31,685	19,365
Total Out-of-State Resources	16,654	15,661	27,601
Total Renewable Resources	**50,558**	**47,346**	**46,966**
Batteries	-	-	-
Pumped Hydro	-	-	-

Table 31. 2030 Statewide out-of-state share in renewable portfolio.

Out of State Resource Accounting	Current Practice 1	Regional 2	Regional 3
Out of State Share in incremental 33-55% Portfolio	33%	33%	59%
Out of State Share in total Portfolio (estimate)	24%	24%	33%

The 33% Muni portfolio is not explicitly modeled. E3 estimates the 33% portfolio consists of 13,442 GWh in-state renewables and 5,073 GWh out-of-state renewables

4.3 Renewable procurement cost results

Total 2030 annual renewable procurement costs for the non-ISO balancing areas, the ISO balancing area, and the total California state are shown below for each of the modeled scenarios.

Table 32. 2030 Annual cost and REC revenue for the non-ISO balancing areas ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$678	$678	$586
Transmission Costs (new construction and wheeling)	$36	$0	$66
Energy Credit for REC Resources*	-	-	-
Net Total Costs	**$714**	**$678**	**$652**
Procurement Savings Relative to Current Practice 1		$36	$62

**Pricing for REC resources is based on the PPA price of a new resource net of its energy value in local markets. Since this energy credit is not captured explicitly in PSO modeling, it is included here as an explicit adjustment. The energy value of all non-REC renewable resources is captured directly through PSO modeling.*

Table 33. 2030 Annual cost and REC revenue for the ISO balancing area ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,619	$2,174	$1,761
Transmission Costs (new construction and wheeling)	$198	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs	**$2,578**	**$1,934**	**$1,840**
Procurement Savings Relative to Current Practice 1		$644	$737

Table 34. 2030 Statewide annual cost and REC revenue ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,297	$2,852	$2,347
Transmission Costs (new construction and wheeling)	$234	$0	$273
Energy Credit for REC Resources*	(240)	(240)	(127)
Net Total Costs	**$3,292**	**$2,612**	**$2,492**
Procurement Savings Relative to Current Practice 1		$680	$799

4.3.1 TOTAL RETAIL REVENUE REQUIREMENT CALCULATION

The total retail revenue requirement used for the purpose of the overall rate-impact analysis presented in this SB350 study is based on EIA's 2015 revenue requirement for the state of California.[20] Consistent with RPS calculator results, E3 assumed 82% of the 2015 revenue requirement is fixed and thus, does not change across the scenarios modeled in this study (i.e., only the remaining 18% is a variable cost covered by TEAM variable procurement cost and an RPS-portfolio-related variable capital investment cost). These fixed costs of serving California retail load that do not vary across the modeled scenarios consist of the costs associated with existing transmission, distribution, generation and renewables, DSM programs, and other fees. These fixed retail costs are assumed to increase at a 1% real escalation rate.

Total retail annual revenue requirement associated with serving California ratepayers is then calculated by adding costs from the following simulation results to the fixed retail costs estimates:

[20] Available here: http://www.eia.gov/electricity/data/eia826/xls/sales_revenue.xls

- Annualized renewable procurement costs associated RPS-portfolio-related incremental capital investment (from RESOLVE, includes incremental renewable procurement, storage incremental to the storage mandate, wheeling and losses charges for out-of-state renewables, energy credit for REC resources, and incremental transmission buildout);
- Wholesale power production, purchase and sales costs (from TEAM calculations);
- Annualized generation capacity cost impacts associated with regional load diversity benefit; and
- Changes in Grid Management Charges (GMC) to California loads

4.4 Renewable Curtailment

The table below shows the 2030 renewable curtailment results for the ISO balancing area.

Table 35. 2030 Renewable curtailment in ISO balancing area.

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Total Curtailment (GWh)	4,818	1,606	1,226
Curtailment as % of available RPS energy	4.5%	1.6%	1.2%

4.5 Results by CREZ

The tables below show the renewable portfolios and the costs to go from 33% RPS to 50% RPS in 2030 detailed by CREZ, for the non-ISO balancing areas, the ISO balancing area, and California State. The study team made a determination of siting the renewables based on both the capacity required to meet 50% RPS and the environmental impact to the various CREZ.

The non-ISO portfolios are hand-picked to provide a representative indication of the potential effects of a regional market on the portfolios of non-ISO utilities. The resource portfolios were selected to be consistent with the overall resource procurement patterns emerging from the RESOLVE analysis.

For the ISO area, several trends are notable. First, the total quantity of resources procured is reduced moving from Current Practice 1 and Regional 2, and again to Regional 3. This is due to two factors: reduced curtailment, requiring less overbuild of the portfolio (between Current Practice 1 and Regional 2) and access to higher quality resources, allowing more energy to be produced per MW of resource installed (between Regional 2 and Regional 3).

Second, there is some variation among the scenarios in terms of the California solar zones selected. For example, development moves from the Westlands zone in Current Practice 1 to the Riverside East zone in Regional 2. This is due to minor differences in the resource output shape that result in very small differences in resource valuation across scenarios. These differences can make an impact in an optimization model like RESOLVE; however, RESOLVE does not consider issues like environmental impact, permitting, siting, water availability, and others that can have a material impact on the success of real projects. Thus, the specific zones that are selected should be thought of as representative of areas with similar resource quality, rather than a firm indication that development is more likely in one area than another.

Finally, Regional 3 results in significant quantities of additional wind development in Wyoming and New Mexico. This development, which requires new transmission lines to be constructed in other states for the benefit of California consumers, is highly unlikely to occur in the absence of a regional transmission entity. While there are a number of projects in various stages of development aimed at providing access to high quality New Mexico and Wyoming wind, none of these projects have been successful in today's bilateral world. FERC's Order 1000 aims at facilitating these types of inter-regional transmission projects, and the ISO along with other utilities are participating in regional planning exercises examining these questions. However, in the absence of a planning entity with a broad regional scope and, most importantly, the authority to allocate costs of new transmission facilities to customers across a broad region, these projects face very significant hurdles that have, thus far, prevented them from successful development.

Table 36. 2030 Munis cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	873	873	486
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	578	578	305
Greater_Imperial_Solar	Solar	923	923	512
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	447	447	318
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	495
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	462
UT_Wind_ExistingTx	Wind	604	604	420
Grand Total		**3,426**	**3,426**	**2,998**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 37. 2030 Munis cumulative renewable portfolio additions in GWh of 2030 annual generation by CREZ.

Resource (CREZ)	Technology	Current Prac	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	2,401	2,401	1,336
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	1,672	1,672	883
Greater_Imperial_Solar	Solar	2,519	2,519	1,397
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,253	1,253	891
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	1,993
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	1,861
UT_Wind_ExistingTx	Wind	1,693	1,693	1,177
Grand Total		**9,538**	**9,538**	**9,538**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 38. Munis annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	$ 167	$ 167	$ 93
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	$ 111	$ 111	$ 58
Greater_Imperial_Solar	Solar	$ 179	$ 179	$ 99
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 221	$ 221	$ 155
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 93
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 87
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 678**	**$ 678**	**$ 586**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 678**	**$ 678**	**$ 586**

Table 39. Munis annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 36	-	-
OR_Wind_REC	Wind	-	-	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 43
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	-	-	-
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 23
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 36**	**-**	**$ 66**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 36**	**-**	**$ 66**

Table 40. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	500	500	500
Greater_Carrizo_Solar	Solar	570	570	-
Kramer_Inyokern_Solar	Solar	375	375	375
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	331	1,984	-
Tehachapi_Solar	Solar	2,500	2,500	1,761
Westlands_Solar	Solar	1,450	-	-
Central_Valley_North_Los_Banos_Wind	Wind	150	150	150
Greater_Carrizo_Wind	Wind	500	500	500
Greater_Imperial_Wind	Wind	400	400	400
Riverside_East_Palm_Springs_Wind	Wind	500	-	-
Solano_Wind	Wind	600	-	-
Tehachapi_Wind	Wind	850	850	850
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,000	115	-
OR_Wind_REC	Wind	1,000	1,000	-
WY_Wind_ExistingTx	Wind	500	500	500
WY_Wind_NewTx_1	Wind	-	-	1,500
AZ_Solar_ExistingTx	Solar	-	500	500
AZ_Solar_REC	Solar	1,000	1,000	1,000
NM_Wind_ExistingTx	Wind	1,000	1,000	1,000
NM_Wind_NewTx_1	Wind	-	-	1,500
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total		**13,226**	**11,944**	**10,536**
Storage				
Li-ion Battery	Storage	472	-	-
Pumped Storage	Storage	500	500	500

Table 41. 2030 ISO cumulative renewable portfolio additions in GWh of 2030 annual generation by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	3,942	3,942	3,942
Greater_Carrizo_Solar	Solar	1,624	1,624	-
Kramer_Inyokern_Solar	Solar	1,115	1,115	1,115
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	930	5,582	-
Tehachapi_Solar	Solar	7,234	7,234	5,096
Westlands_Solar	Solar	3,987	-	-
Central_Valley_North_Los_Banos_Wind	Wind	394	394	394
Greater_Carrizo_Wind	Wind	1,358	1,358	1,358
Greater_Imperial_Wind	Wind	1,244	1,244	1,244
Riverside_East_Palm_Springs_Wind	Wind	1,448	-	-
Solano_Wind	Wind	1,436	-	-
Tehachapi_Wind	Wind	2,601	2,601	2,601
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	2,803	321	-
OR_Wind_REC	Wind	2,803	2,803	-
WY_Wind_ExistingTx	Wind	1,708	1,708	1,708
WY_Wind_NewTx_1	Wind		-	6,044
AZ_Solar_ExistingTx	Solar	-	1,489	1,489
AZ_Solar_REC	Solar	2,978	2,978	2,978
NM_Wind_ExistingTx	Wind	3,416	3,416	3,416
NM_Wind_NewTx_1	Wind		-	6,044
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total		**41,021**	**37,809**	**37,429**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 42. ISO annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	$ 379	$ 379	$ 379
Greater_Carrizo_Solar	Solar	$ 90	$ 90	-
Kramer_Inyokern_Solar	Solar	$ 59	$ 59	$ 59
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	$ 52	$ 313	-
Tehachapi_Solar	Solar	$ 394	$ 394	$ 278
Westlands_Solar	Solar	$ 284	-	-
Central_Valley_North_Los_Banos_Wind	Wind	$ 21	$ 21	$ 21
Greater_Carrizo_Wind	Wind	$ 68	$ 68	$ 68
Greater_Imperial_Wind	Wind	$ 55	$ 55	$ 55
Riverside_East_Palm_Springs_Wind	Wind	$ 84	-	-
Solano_Wind	Wind	$ 85	-	-
Tehachapi_Wind	Wind	$ 126	$ 126	$ 126
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 202	$ 16	-
OR_Wind_REC	Wind	$ 209	$ 142	-
WY_Wind_ExistingTx	Wind	$ 52	$ 52	$ 52
WY_Wind_NewTx_1	Wind	-	-	$ 132
AZ_Solar_ExistingTx	Solar	-	$ 70	$ 70
AZ_Solar_REC	Solar	$ 167	$ 141	$ 141
NM_Wind_ExistingTx	Wind	$ 104	$ 104	$ 104
NM_Wind_NewTx_1	Wind	-	-	$ 132
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 2,431**	**$ 2,028**	**$ 1,615**
Storage				
Li-ion Battery	Storage	$ 43	-	-
Pumped Storage	Storage	$ 146	$ 146	$ 146
Grand Total with Storage		**$ 2,620**	**$ 2,174**	**$ 1,761**

Table 43. ISO annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state		-	-	-
OR_Wind_ExistingTx	Wind	$ 34	-	-
OR_Wind_REC	Wind	$ 20	-	-
WY_Wind_ExistingTx	Wind	$ 33	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 131
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ 39	-	-
NM_Wind_ExistingTx	Wind	$ 72	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 75
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 198**	-	**$ 207**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 198**	-	**$ 207**

Table 44. ISO annualized incremental energy credit for REC resources in 2030 by CREZ (REC resources only; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	-	-	-
OR_Wind_REC	Wind	$ (113)	$ (113)	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	-
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ (127)	$ (127)	$ (127)
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	-
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		$ (240)	$ (240)	$ (127)
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		$ (240)	$ (240)	$ (127)

Table 45. 2030 Statewide cumulative renewable portfolio additions in MW of installed capacity by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	500	500	500
Greater_Carrizo_Solar	Solar	570	570	-
Kramer_Inyokern_Solar	Solar	375	375	375
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	331	1,984	-
Tehachapi_Solar	Solar	2,500	2,500	1,761
Westlands_Solar	Solar	2,323	873	486
Central_Valley_North_Los_Banos_Wind	Wind	150	150	150
Greater_Carrizo_Wind	Wind	500	500	500
Greater_Imperial_Wind	Wind	400	400	400
Riverside_East_Palm_Springs_Wind	Wind	500	-	-
Solano_Wind	Wind	600	-	-
Tehachapi_Wind	Wind	850	850	850
Owens_Valley_Solar	Solar	578	578	305
Greater_Imperial_Solar	Solar	923	923	512
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	1,447	562	318
OR_Wind_REC	Wind	1,000	1,000	-
WY_Wind_ExistingTx	Wind	500	500	500
WY_Wind_NewTx_1	Wind	-	-	1,995
AZ_Solar_ExistingTx	Solar	-	502	502
AZ_Solar_REC	Solar	1,000	1,000	1,000
NM_Wind_ExistingTx	Wind	1,000	1,000	1,000
NM_Wind_NewTx_1	Wind	-	-	1,962
UT_Wind_ExistingTx	Wind	604	604	420
Grand Total		**16,652**	**15,371**	**13,536**
Storage				
Li-ion Battery	Storage	472	-	-
Pumped Storage	Storage	500	500	500

Table 46. 2030 Statewide cumulative renewable portfolio additions in GWh of 2030 renewable generation by CREZ.

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	3,942	3,942	3,942
Greater_Carrizo_Solar	Solar	1,624	1,624	-
Kramer_Inyokern_Solar	Solar	1,115	1,115	1,115
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	930	5,582	-
Tehachapi_Solar	Solar	7,234	7,234	5,096
Westlands_Solar	Solar	6,388	2,401	1,336
Central_Valley_North_Los_Banos_Wind	Wind	394	394	394
Greater_Carrizo_Wind	Wind	1,358	1,358	1,358
Greater_Imperial_Wind	Wind	1,244	1,244	1,244
Riverside_East_Palm_Springs_Wind	Wind	1,448	-	-
Solano_Wind	Wind	1,436	-	-
Tehachapi_Wind	Wind	2,601	2,601	2,601
Owens_Valley_Solar	Solar	1,672	1,672	883
Greater_Imperial_Solar	Solar	2,519	2,519	1,397
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	4,056	1,574	891
OR_Wind_REC	Wind	2,803	2,803	-
WY_Wind_ExistingTx	Wind	1,708	1,708	1,708
WY_Wind_NewTx_1	Wind	-	-	8,037
AZ_Solar_ExistingTx	Solar	-	1,489	1,489
AZ_Solar_REC	Solar	2,978	2,978	2,978
NM_Wind_ExistingTx	Wind	3,416	3,416	3,416
NM_Wind_NewTx_1	wind	-	-	7,905
UT_Wind_ExistingTx	Wind	1,693	1,693	1,177
Grand Total		**50,559**	**47,347**	**46,967**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-

Table 47. Statewide annualized incremental investment costs in 2030 by CREZ (excl. transmission; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	$ 379	$ 379	$ 379
Greater_Carrizo_Solar	Solar	$ 90	$ 90	-
Kramer_Inyokern_Solar	Solar	$ 59	$ 59	$ 59
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	$ 52	$ 313	-
Tehachapi_Solar	Solar	$ 394	$ 394	$ 278
Westlands_Solar	Solar	$ 451	$ 167	$ 93
Central_Valley_North_Los_Banos_Wind	Wind	$ 21	$ 21	$ 21
Greater_Carrizo_Wind	Wind	$ 68	$ 68	$ 68
Greater_Imperial_Wind	Wind	$ 55	$ 55	$ 55
Riverside_East_Palm_Springs_Wind	Wind	$ 84	-	-
Solano_Wind	Wind	$ 85	-	-
Tehachapi_Wind	Wind	$ 126	$ 126	$ 126
Owens_Valley_Solar	Solar	$ 111	$ 111	$ 58
Greater_Imperial_Solar	Solar	$ 179	$ 179	$ 99
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 423	$ 237	$ 155
OR_Wind_REC	Wind	$ 209	$ 142	-
WY_Wind_ExistingTx	Wind	$ 52	$ 52	$ 52
WY_Wind_NewTx_1	Wind	-	-	$ 225
AZ_Solar_ExistingTx	Solar	-	$ 70	$ 70
AZ_Solar_REC	Solar	$ 167	$ 141	$ 141
NM_Wind_ExistingTx	Wind	$ 104	$ 104	$ 104
NM_Wind_NewTx_1	Wind	-	-	$ 219
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 3,108**	**$ 2,706**	**$ 2,201**
Storage				
Li-ion Battery	Storage	$ 43	-	-
Pumped Storage	Storage	$ 146	$ 146	$ 146
Grand Total with Storage		**$ 3,297**	**$ 2,852**	**$ 2,347**

Table 48. Statewide annualized incremental transmission costs in 2030 by CREZ (new construction and wheeling; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	$ 71	-	-
OR_Wind_REC	Wind	$ 20	-	-
WY_Wind_ExistingTx	Wind	$ 33	-	-
WY_Wind_NewTx_1	Wind	-	-	$ 175
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ 39	-	-
NM_Wind_ExistingTx	Wind	$ 72	-	-
NM_Wind_NewTx_1	Wind	-	-	$ 98
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ 234**	-	**$ 273**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ 234**	-	**$ 273**

Table 49. Statewide annualized incremental energy credit for REC resources in 2030 by CREZ (REC resources only; $MM).

Resource (CREZ)	Technology	Current Practice 1	Regional 2	Regional 3
Greater_Imperial_Geothermal	Geothermal	-	-	-
Greater_Carrizo_Solar	Solar	-	-	-
Kramer_Inyokern_Solar	Solar	-	-	-
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	-	-	-
Tehachapi_Solar	Solar	-	-	-
Westlands_Solar	Solar	-	-	-
Central_Valley_North_Los_Banos_Wind	Wind	-	-	-
Greater_Carrizo_Wind	Wind	-	-	-
Greater_Imperial_Wind	Wind	-	-	-
Riverside_East_Palm_Springs_Wind	Wind	-	-	-
Solano_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	-	-	-
Owens_Valley_Solar	Solar	-	-	-
Greater_Imperial_Solar	Solar	-	-	-
Sonoma_Geothermal	Geothermal	-	-	-
Out-of-state				
OR_Wind_ExistingTx	Wind	-	-	-
OR_Wind_REC	Wind	$ (113)	$ (113)	-
WY_Wind_ExistingTx	Wind	-	-	-
WY_Wind_NewTx_1	Wind	-	-	-
AZ_Solar_ExistingTx	Solar	-	-	-
AZ_Solar_REC	Solar	$ (127)	$ (127)	$ (127)
NM_Wind_ExistingTx	Wind	-	-	-
NM_Wind_NewTx_1	Wind	-	-	-
UT_Wind_ExistingTx	Wind	-	-	-
Grand Total without Storage		**$ (240)**	**$ (240)**	**$ (127)**
Storage				
Li-ion Battery	Storage	-	-	-
Pumped Storage	Storage	-	-	-
Grand Total with Storage		**$ (240)**	**$ (240)**	**$ (127)**

4.6 Sensitivity analysis results

The robustness of the base case results is tested with a large set of sensitivity cases. Non-ISO Muni results are held constant across all the sensitivities and can be found in section 3.2 and 3.3. Only the ISO inputs and results vary in these sensitivity analyses.

4.6.1 SUMMARY OF SENSITIVITY RESULTS

An overview of the renewable procurement cost results for California state, which includes the Muni results that do not vary by sensitivity, is shown in the tables below.

The sensitivity results show the savings are relatively robust, with savings ranging from $391-1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings. The highest procurement cost savings occur in the 55% RPS sensitivity, which interestingly might become the de facto base case after PG&E's recent decision to close Diablo canyon in 2025 and replace its output with renewables.

Table 50. Overview of 2030 procurement cost savings for California State across all sensitivities.

Renewable Portfolio cost savings from regional market implementation ($MM)	Regional 2 vs. Current Practice 1	Regional 3 vs. Current Practice 1
Base Case	$680	$799
A. High coordination under bilateral markets	$391	$511
B. High energy efficiency	$576	$692
C. High flexible loads	$495	$616
D. Low portfolio diversity	$895	$1,004
E. High rooftop PV	$838	$944
F. High out-of-state resource availability	$578	$661
G. Low cost solar	$510	$647
H. 55% RPS	$1,164	$1,341

Table 51. Overview of 2030 curtailment results for the ISO balancing area across all sensitivities (% of annual RPS generation curtailed).

Renewable Energy Curtailment	Current Practice 1	Regional 2	Regional 3
Base Case	4.5%	1.6%	1.2%
A. High coordination under bilateral markets	2.0%	1.6%	1.2%
B. High energy efficiency	4.8%	1.7%	1.2%
C. High Out of State Availability	3.6%	1.3%	1.1%
D. High flexible loads	4.3%	1.9%	1.7%
E. Low portfolio diversity	5.9%	1.5%	1.2%
F. High rooftop PV	6.8%	2.0%	1.5%
G. Low solar cost	5.7%	1.8%	1.2%
H. High RPS (55%)	7.1%	1.8%	1.3%

In the sections that follow, the sensitivities are explained shortly and detailed portfolio and procurement cost results are shown.

4.6.2 HIGH COORDINATION UNDER BILATERAL MARKETS

In this "current practices" sensitivity, the ISO simultaneous export limit is increased from 2,000 MW to 8,000 MW in Current Practice 1, while the procurement and operations are kept at current practices (ISO-wide). This reflects a scenario where there is no regional coordination, but high coordination under the current bilateral markets allows for higher exports. This sensitivity is also referred to as "Sensitivity 1B" in some of the public material, including the stakeholder presentation slides from May 24 - 25. The results for Sensitivity 1B in these slides for are the same as the results for Current Practice 1 in the table below.

The increased export limits in Current Practice 1 create more room for in-state solar as well as solar in the Southwest at the expense of Northwest wind, which has less diversification benefits in this less-constrained scenario. Curtailment and total costs in Current Practice 1 go down, resulting in lower benefits from regional coordination in Regional 2 and 3 (compared to the Current Practice 1 base case).

Table 52. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high coordination under bilateral markets" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	5,904	5,429	2,136
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	115	-
Northwest Wind RECs	-	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	272	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,404**	**7,829**	**4,536**
Total Out-of-State Resources	**2,772**	**4,115**	**6,000**
Total Renewable Resources	**12,176**	**11,944**	**10,536**
Batteries	-	-	-
Pumped Hydro	500	500	500

Table 53. 2030 Annual incremental cost and REC revenue for the ISO area for the "high coordination under bilateral markets" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,262	$2,174	$1,761
Transmission Costs (new construction and wheeling)	$155	$0	$207
Energy Credit for REC Resources*	-$127	-$240	-$127
Net Total Costs - CAISO	**$2,289**	**$1,934**	**$1,840**
Net Total Costs -Statewide (incl. Munis)	**$3,003**	**$2,612**	**$2,492**
Statewide Procurement Savings Relative to Current Practice 1		$391	$511

4.6.3 HIGH ENERGY EFFICIENCY

In this sensitivity, the additional achievable energy efficiency (AAEE) is doubled by 2030, lowering retail sales and thus lowering the amount of renewables required to meet the RPS goal. The reduction in load lowers the amount of renewable generation that can benefit from regionalization and thus lowers total benefits.

Table 54. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high energy efficiency" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	2,875	3,580	-
California Wind	3,000	1,900	1,480
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	697	-	-
Northwest Wind RECs	1,000	364	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**6,375**	**5,980**	**1,980**
Total Out-of-State Resources	**4,197**	**3,364**	**6,000**
Total Renewable Resources	**10,572**	**9,344**	**7,980**
Batteries	388	-	-
Pumped Hydro	500	500	500

Table 55. 2030 Annual incremental cost and REC revenue for the ISO area for the "high energy efficiency" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,128	$1,776	$1,367
Transmission Costs (new construction and wheeling)	$188	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,076**	**$1,536**	**$1,446**
Net Total Costs -Statewide (incl. Munis)	**$2,790**	**$2,214**	**$2,098**
Statewide Procurement Savings Relative to Current Practice 1		$576	$692

4.6.4 HIGH FLEXIBLE LOADS

In this sensitivity, 3,000 MW of 4-hour batteries are added in all scenarios. Solar becomes more economic due to the additional flexibility in the system and the need for battery storage is reduced. As a result, benefits from regional markets go down.

Table 56. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high flexible" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	6,126	6,218	2,326
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	1,000	455	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,626**	**8,618**	**4,726**
Total Out-of-State Resources	**3,500**	**3,455**	**6,000**
Total Renewable Resources	**13,126**	**12,073**	**10,726**
Batteries	87	-	-
Pumped Hydro	500	500	500

Table 57. 2030 Annual incremental cost and REC revenue for the ISO area for the "high flexible loads" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,500	$2,205	$1,790
Transmission Costs (new construction and wheeling)	$164	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,424**	**$1,965**	**$1,870**
Net Total Costs -Statewide (incl. Munis)	**$3,138**	**$2,643**	**$2,522**
Statewide Procurement Savings Relative to Current Practice 1		$495	$616

4.6.5 LOW PORTFOLIO DIVERSITY

In this sensitivity, pumped hydro and geothermal are taken out of the portfolios and total California wind is restricted to 2,000 MW in all scenarios. As a result, the portfolios are much more solar-intensive, which creates more value for diversification of load and resources through regional markets. The benefits therefore go up significantly.

Table 58. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "low portfolio diversity" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,549	5,806	3,905
California Wind	2,000	2,000	1,500
California Geothermal	-	-	-
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	500	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**9,549**	**7,806**	**5,405**
Total Out-of-State Resources	**5,000**	**5,000**	**6,000**
Total Renewable Resources	**14,549**	**12,806**	**11,405**
Batteries	1,070	-	-
Pumped Hydro	-	-	-

Table 59. 2030 Annual incremental cost and REC revenue for the ISO area for the "low portfolio diversity" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,504	$1,863	$1,460
Transmission Costs (new construction and wheeling)	$218	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,482**	**$1,623**	**$1,540**
Net Total Costs -Statewide (incl. Munis)	**$3,196**	**$2,301**	**$2,192**
Statewide Procurement Savings Relative to Current Practice 1		$895	$1,004

4.6.6 HIGH ROOFTOP PV

In this sensitivity, the total installed capacity of rooftop PV in the ISO balancing area is increased from 16 GW to 21 GW by 2030. As a result, the total renewable generation, when also including rooftop PV, is much more solar-intensive, which creates more value for diversification of load and resources through regional markets. In Current Practice 1, additional battery storage is selected to integrate the additional rooftop PV. The overall effect is that the benefits of regional markets go up.

Table 60. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high rooftop PV" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	4,771	3,403	992
California Wind	3,000	1,900	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**8,271**	**5,803**	**3,392**
Total Out-of-State Resources	**4,500**	**5,000**	**6,000**
Total Renewable Resources	**12,771**	**10,803**	**9,392**
Batteries	1,047	-	-
Pumped Hydro	500	500	500

Table 61. 2030 Annual incremental cost and REC revenue for the ISO area for the "high rooftop PV" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,584	$1,980	$1,580
Transmission Costs (new construction and wheeling)	$198	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,542**	**$1,740**	**$1,660**
Net Total Costs -Statewide (incl. Munis)	**$3,256**	**$2,418**	**$2,312**
Statewide Procurement Savings Relative to Current Practice 1		$838	$944

4.6.7 HIGH OUT OF STATE AVAILABILITY

In this sensitivity, Southwest solar RECs and Northwest wind RECs renewable potential is increased so that they account for up to half of the 50% RPS goal (ISO only), which equals to a renewable potential of 4,526 MW of Northwest wind RECs and 4,279 MW of Southwest solar RECs. The model picks all the available SW solar RECs and no NW wind RECS, and less battery storage is required because the RECs don't need to be balanced in-state. The benefits are lower because lower cost solar RECs displace marginal California solar and out-of-state wind in Current Practice 1.

Table 62. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high out of state availability" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	3,349	2,962	-
California Wind	3,000	1,900	1,750
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	-	-	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	4,279	4,279	3,188
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**6,849**	**5,362**	**2,250**
Total Out-of-State Resources	**5,779**	**6,279**	**8,188**
Total Renewable Resources	**12,628**	**11,641**	**10,438**
Batteries	98	-	-
Pumped Hydro	500	500	500

Table 63. 2030 Annual incremental cost and REC revenue for the ISO area for the "high out of state availability" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,359	$2,088	$1,711
Transmission Costs (new construction and wheeling)	$271	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,390**	**$1,848**	**$1,790**
Net Total Costs -Statewide (incl. Munis)	**$3,104**	**$2,526**	**$2,443**
Statewide Procurement Savings Relative to Current Practice 1		$578	$661

4.6.8 LOW SOLAR COST

In this sensitivity, solar costs are reduced to $1/W-DC by 2025. As a result, solar procurement in California goes up significantly, while NW wind procurement goes down. NM wind and WY wind are still selected in Regional 3. The benefits of regional markets go down because the lower cost California solar displaces out-of-state wind in Current Practice 1. There are still significant curtailment reduction benefits in Regional 3.

Table 64. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "low solar cost" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	7,354	6,641	2,752
California Wind	3,000	1,900	1,250
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	-	-	-
Northwest Wind RECs	344	-	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	1,500
Southwest Solar, Existing Transmission	-	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**10,854**	**9,041**	**4,502**
Total Out-of-State Resources	**2,844**	**3,000**	**6,000**
Total Renewable Resources	**13,698**	**12,041**	**10,502**
Batteries	627	-	-
Pumped Hydro	500	500	500

Table 65. 2030 Annual incremental cost and REC revenue for the ISO area for the "low solar cost" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$2,512	$2,189	$1,759
Transmission Costs (new construction and wheeling)	$151	$0	$207
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$2,423**	**$1,949**	**$1,838**
Net Total Costs -Statewide (incl. Munis)	**$3,137**	**$2,627**	**$2,490**
Statewide Procurement Savings Relative to Current Practice 1		$510	$647

4.6.9 HIGH RPS (55%)

This sensitivity models a 55% RPS goal. To meet this higher RPS goal, the model shows a significant increase in California solar procurement, as well as additional WY wind procurement in Regional 3. Benefits from regional markets are significantly higher because it is much more costly to meet the higher RPS in Current Practice 1.

Table 66. 2030 ISO cumulative renewable portfolio additions in MW of installed capacity for the "high RPS (50%)" sensitivity.

New Resources (MW)	Current Practice 1	Regional 2	Regional 3
California Solar	9,840	7,327	4,313
California Wind	3,000	3,000	1,900
California Geothermal	500	500	500
Northwest Wind, Existing Transmission	1,000	1,000	-
Northwest Wind RECs	1,000	1,000	-
Utah Wind, Existing Transmission	-	-	-
Wyoming Wind, Existing Transmission	500	500	500
Wyoming Wind, New Transmission	-	-	2,628
Southwest Solar, Existing Transmission	500	500	500
Southwest Solar RECs	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000
New Mexico Wind, New Transmission	-	-	1,500
Total CA Resources	**13,340**	**10,827**	**6,713**
Total Out-of-State Resources	**5,000**	**5,000**	**7,128**
Total Renewable Resources	**18,340**	**15,827**	**13,841**
Batteries	1,309	-	-
Pumped Hydro	500	500	500

Table 67. 2030 Annual incremental cost and REC revenue for the ISO area for the "High RPS (55%)" sensitivity ($MM).

Costs and REC Revenue ($MM)	Current Practice 1	Regional 2	Regional 3
Annualized Investment Costs	$3,693	$2,783	$2,214
Transmission Costs (new construction and wheeling)	$218	$0	$305
Energy Credit for REC Resources*	-$240	-$240	-$127
Net Total Costs - CAISO	**$3,671**	**$2,543**	**$2,392**
Net Total Costs -Statewide (incl. Munis)	**$4,385**	**$3,221**	**$3,044**
Statewide Procurement Savings Relative to Current Practice 1		$1,164	$1,341

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Senate Bill 350 Study

Volume V: Production Cost Analysis

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THE Brattle GROUP

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

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Volume V. Production Cost Analysis

A. Introduction: Production Cost Simulations

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate or regional entity ("Regional ISO"). SB 350, in part, specifically requires an evaluation of "overall benefits to California ratepayers" and "emissions of greenhouse gases and other air pollutants."

The Brattle Group has been engaged to develop simulations of the wholesale electric system and to evaluate certain portions of overall ratepayer impacts, and on electric sector greenhouse gases ("GHGs"). This report evaluates impacts on the variable cost of producing power to meet electric loads ("production costs"), and on associated CO_2 emissions from the electric sector.[1] This Volume V is part of the overall study, consisting of Volumes I through XII, in response to SB 350's legislative requirements. The estimated production costs and resulting California impact metrics are one element of the ratepayer impact analysis conducted by The Brattle Group and Energy and Environmental Economics, Inc. ("E3") in Volume VII. Similarly, the estimated CO_2 emissions impacts are part of a larger environmental study conducted by Aspen Environmental Group in Volume IX.

We simulated the wholesale power markets in California and in the rest of the entire Western Electricity Coordinating Council ("WECC") system by using a production cost model as a foundational tool to estimate: (1) production cost impacts associated with de-pancaked transmission and scheduling charges, and jointly-optimized generating unit commitment and dispatch, and (2) changes in generation output, fuel use, and emissions of CO_2.[2] Portions of the

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1 GHGs include carbon dioxide (CO_2), methane (CH_4), nitrogen trifluoride (NF_3), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases. Our evaluation of GHGs focuses on CO_2 since it represents 99% of all GHGs (in CO_2-equivalent terms) from electric sector operations.

2 The term "WECC" is often generalized to refer to the entire western electric grid's physical system, stakeholders, and/or markets. When discussing WECC Balancing Authorities, WECC's system studies, and WECC's production cost models, we use the term's specific meaning. Otherwise, we use the term's more general meaning.

production cost model inform an evaluation of the reliability of the high-voltage electric system and integration of renewable energy resources in California and the rest of the region. The simulation results are used as inputs to analyze the creation or retention of jobs and other benefits to the California economy, and environmental impacts in California and elsewhere.

For the simulations, we used the Power Systems Optimizer ("PSO") software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual ISO operations. In that regard, PSO is similar to "Gridview," the simulation tool that CAISO and the WECC use for their system planning analyses.

To estimate the impacts of a regional market, we analyzed five baseline scenarios using PSO.

- In the "**2020 Current Practice**" and "**2030 Current Practice 1**"[3] scenarios we consider a wholesale market that operates under conditions similar to today's system across WECC, with CAISO operating its balancing area under a centralized wholesale market and with the WECC operating as many individual Balancing Authorities with bilateral trading among them. The simulations for these two baseline scenarios represent the "Current Practice" market structure by using economic and operational hurdles between the WECC balancing areas, and by limiting the ability for each balancing area to share the use of generating capacity to meet each individual balancing area's operating reserve requirements. In addition, California's ability to offload oversupply from wind and solar resources is limited due to assumed bilateral trading barriers.
- In the remaining three scenarios "**2020 CAISO+PAC**", "**2030 Regional 2**", and "**2030 Regional 3**", we relieve economic and operational hurdles within the assumed Regional ISO's footprint, reduce operating reserve requirements, and allow for increased reserve sharing. By 2030, with a broad regional footprint that includes all of the WECC except for the federal Power Marketing Agencies ("WECC without PMAs"), centralized markets and operations would attract more development of renewables, beyond the states' existing Renewable Portfolio Standards ("RPS").

3 The "2030 Current Practice 1" scenario was previously referred to by the study team as case "1A," as shown in preliminary presentations, written material, and data release prior to publishing this report.

In addition to the baseline scenarios, we analyzed six sensitivities in the production cost simulations to estimate the potential impacts of modeling scope and assumptions on the study results:

- "**2020 Regional ISO**" to evaluate widespread regionalization under nearer-term (*i.e.*, 2020) market conditions;
- "**2030 Current Practice 1B**" to depict effects of lower barriers in the bilateral trading market without regionalization;
- "**2030 Regional ISO 1**" to isolate the impact of regional market operations while holding the renewable portfolio exactly the same as in 2030 Current Practice 1 (*i.e.*, without re-optimizing the renewable portfolio assumptions);
- "**2030 Regional ISO 3 without renewables beyond RPS**" to study impacts assuming no additional renewable resources facilitated by the regional market; and
- "**2030 Current Practice 1 with WECC-wide CO_2**" and "**2030 Regional ISO 3 with WECC-wide CO_2**" to test the implications of a modest $15/tonne CO_2 allowance cost across the U.S. WECC footprint outside of California as a proxy for compliance with EPA's Clean Power Plan ("CPP").

As a starting point to the simulations, we relied on the database contained in CAISO's own production cost model used for its 2015/16 Transmission Planning Process ("TPP"). That model is based on many assumptions, particularly for outside of California, developed for the WECC's production cost model by the Transmission Expansion Planning Policy Committee ("TEPPC;" specifically, the 2024 Common Case v1.5). Both CAISO and TEPPC models utilize the Gridview software. With the CAISO's TPP model as the starting point, we updated key assumptions on California loads, distributed solar photovoltaics ("PV"), natural gas prices, and California GHG price assumptions based on the California Energy Commission's ("CEC's") 2015 Integrated Energy Policy Report ("2015 IEPR") data. We also updated unit additions and retirements, the transmission wheeling charges between balancing areas, the representation of transmission projects that are expected to be built consistent with the assumptions defined in each of the scenarios, the modeling of pumped storage hydroelectric generators, the specifications of unit commitment for natural gas-fired generators, and the operating reserve requirements.

1. Production Cost Optimization and Decision Cycles

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only.

Recognizing modern system challenges, PSO has the capability to capture the effects on thermal unit commitment of the increasing variability to which systems operations are exposed due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system), as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (*e.g.*, load, fuel prices, *etc.*) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which would occur at different points in time and with different amounts of information about system conditions.

PSO uses mixed-integer programming to solve for optimized system-wide commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in jointly-optimized competitive energy and ancillary services markets.

For the purposes of the SB 350 study, we have developed the model assumptions to simulate day-ahead market outcomes in three cycles as shown in Figure 1.

- In the first cycle, PSO calculates the marginal loss factors on the transmission system. The marginal losses affect the locational prices and economics of generators.
- In the second cycle, PSO optimizes unit commitment decisions, particularly for resources with limited operational flexibility (*e.g.*, units that start up slowly or have long minimum online and offline periods). In this cycle, PSO determines which resources to start up to meet energy and operating reserve needs in each hour of the following day, while anticipating the needs one week ahead. While the model has the capability to address uncertainties between the day-ahead and real-time markets, we have not operated the model in such a mode. Thus, the entire simulation effort for the SB 350 study is conducted with perfect foresight. This means that the unit commitment is always efficiently determined since no system changes (*e.g.*, changes in load or generation between the day-ahead and the real-time market) are simulated that would alter the unit commitment after the day-ahead schedule is complete.

- In the third cycle, PSO solves for economic dispatch of resources given the unit commitment decisions made in the second cycle. Explicit modeling of the commitment and dispatch cycles allows us to more accurately represent the preferences of individual balancing authorities to commit local resources for reliability, but share the provision of energy around a given commitment. This consideration is captured through the use of a "bilateral trading adder" on the bilateral transfers between areas and we have used adders that are higher for unit commitment in the second cycle than for generation dispatch in the third cycle.

Figure 1: PSO Decision Cycles

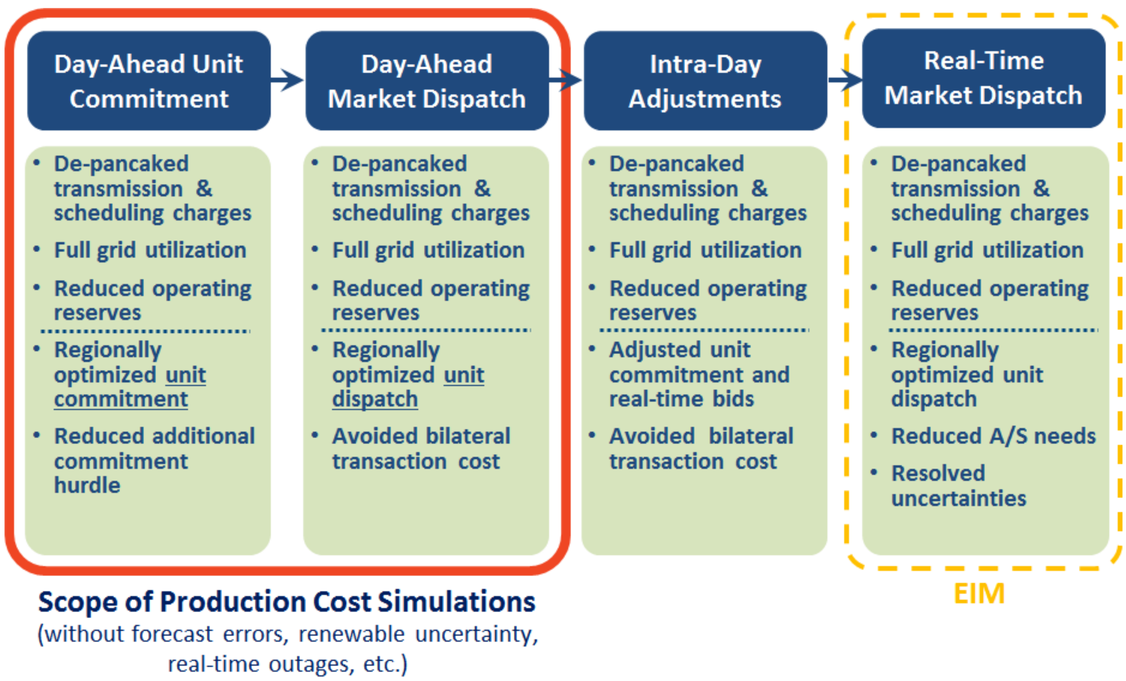
	Cycle	Description
Cycle 1	Marginal Losses	Calculates marginal loss factors
Cycle 2	Unit Commitment	Makes commitment decisions based on the up/down time and the magnitude of minimum generation amount for different types of generation resources (longer for baseload and older gas-fired combined-cycles and shorter for peakers) and decide which resources would operate to provide energy versus reserves
Cycle 3	Unit Dispatch	Dispatches resources for energy; allows more economic sharing of resources to provide energy and reserves around a fixed commitment determined in Cycle 2

2. Limitations of Production Cost Modeling

While production cost simulations in the PSO model provide valuable insights on potential impacts of a regional market on operational cost and emissions, our simulations reflect limitations typical to these types of models. Further, because of the assumptions made, either generally or specifically for each scenario, the simulations are conducted to err on the side of providing conservatively low benefits. The conservatively low benefits in part are due to the system being dispatched fully efficiently even under the bilateral markets simulated in the 2020 Current Practice and 2030 Current Practice scenarios, subject only to the "hurdle rates" imposed on transactions between balancing areas. This does not reflect other inefficiencies of the current market structure, such as less optimized generation dispatch of existing balancing areas or transmission scheduling constraints that do not fully reflect the physical capabilities of the grid.

As shown in Figure 2, the simulations are set up to capture impacts only on day-ahead market operations. This means they do not include the benefits of regional market operations in addressing uncertainties in real-time load and renewable generation (which are partly addressed in CAISO's Energy Imbalance Market ("EIM")). This limitation to day-ahead market operations avoids quantifying the regional market benefits that (at least in part) can be captured by an expanded regional EIM. Note, however, that the EIM does not capture all real-time benefits provided by an ISO-operated market, such as intra-day unit commitment, the full dispatch of all resources, de-pancaked transmission rates on an intra-day and longer-term basis, reduced operating reserve needs, or frequency regulation benefits.

Figure 2: Scope of Production Cost Simulations



In addition, the production cost simulations are limited in capturing some of the impacts of regional market operations (which yields to conservative estimates of benefits), because they:

- Consider only "normal" weather, hydro, and load conditions;
- Do not include any transmission outages or operational de-rates on transfer limits;
- Do not include any challenging market conditions (*e.g.*, Aliso Canyon impacts);
- Do not fully account for improved regional optimization of hydro resources (almost identical hydro dispatch with or without regional markets);
- Assume perfectly competitive bidding behavior (does not capture competitive benefits);

- Use "generic" TEPPC and CEC plant and fuel cost assumptions, which understate the true variation in plant efficiencies and fuel costs (and thus the benefit of optimized regional dispatch);
- Assume all balancing authorities in the WECC already utilize an "ISO-like" optimized security-constrained economic unit commitment and dispatch even under the Current Practice scenarios;
- Do not fully account for less efficient utilization of the existing grid in bilateral markets;
- Do not capture inefficiencies of bilateral trading blocks, contract path scheduling, and unscheduled flows;
- Do not consider any long-term benefits from improved regional and inter-regional transmission planning and improved long-term price signals for generation investments; and;
- Do not fully account for the reduction in counterparties' transaction costs associated with bilateral trading activities (net of cost to ISO participation).

As estimated in an analysis by the Natural Resource Defense Council (NRDC), for example, the annual value of benefits to California not quantified in this SB 350 analysis could range from $90 million in 2020 to more than $500 million in 2030.[4]

For example, the improvements in utilization of the existing grid that are made possible by organized ISO markets have been documented well in other studies and the WECC. A 2003 MISO study showed that its bilateral Day-1 market did not utilize between 7.7% and 16.4% of the existing grid capacity during congestion management events.[5] This previously-unused capacity is now utilized fully in MISO's regional Day-2 market with regional security-constrained economic dispatch. Similar opportunities exist for improved utilization of the grid in the WECC. As shown in Figure 3, analysis of 2012 WECC path-flow data showed that 5–25% of grid capacity remains unutilized during unscheduled flow ("USF") mitigation events on the WECC Path 66 and Path 30.[6] While EIM will improve existing grid utilization somewhat, a fully integrated market across the whole WECC would result in additional improvements, including through optimized

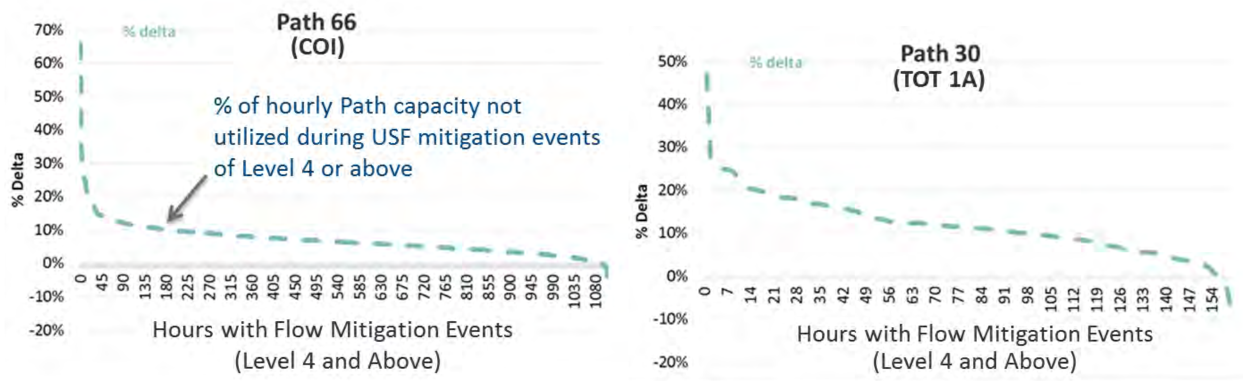
[4] See https://www.nrdc.org/experts/carl-zichella/count-all-benefits-regional-expansion

[5] McNamara, Ronald R., "Affidavit on behalf of Midwest ISO before the Federal Energy Regulatory Commission, Docket ER04-691-000, on June 25, 2004

[6] 2012 was the most recent year for which complete data were available.

unit commitment and day-ahead pre-dispatch that considers the full physical capability of the market region's grid, without limits imposed by contractual scheduling rights. The improved utilization of the existing grid in the WECC (incremental to EIM) that would be achieved by a regional market is not reflected in our simulation results.

Figure 3: Unutilized Path Capacity During Flow-Mitigation Events on WECC Paths 66 and 30
(Measured as % difference between limit and flow during USF mitigation events Level 4 or above)



In the context of modeling limitations, it is important to understand that production cost simulations models such as PSO focus on operating costs and do not model resource investment or retirement decisions, such as resource additions needed to meet planning reserve requirements (in light of load growth or retirements) or RPS. New and retired capacity must be part of the simulation input assumptions, and those inputs are informed by company announcements and various planning studies, WECC stakeholder input to TEPPC and the ISO, resource adequacy calculations (for generic additions to meet planning reserve requirements), and E3's RESOLVE model (for generic additions to meet resource development goals).

The PSO model analyzes only the wholesale electric sector. It does not model other sectors, such as transportation or natural gas markets. So, using these examples, PSO does not endogenously determine California's GHG allowance prices or natural gas prices. These are fixed inputs to the model.

Finally, PSO's advanced optimization algorithms, and its detailed representation of a nodal system and individual generating units, make analyzing a single case for a single year computationally very time-consuming. This level of system and modeling detail naturally limits how many PSO runs can be practically implemented for this study. For example, it would be quite impractical to attempt to run every year between 2020 and 2030 (and not very informative if model assumptions do not change much in those intervening years); it would also be impractical to use PSO to run a large volume of sensitivities, scenarios, or probabilistic "Monte-Carlo" iterations.

The computationally time-consuming nature of these types of market models limits the simulations to rely on simplified assumptions that will tend to understate production costs, market prices, and the cost of system constraints. As noted above, examples of the simplifying assumptions used in these types of simulations are: (1) normal weather and normal loads in all balancing areas (*i.e.*, no diverging or extreme weather events that would create additional regional flows); (2) a fully intact transmission system (*i.e.*, no transmission outages that would create N-2 conditions and more severe transmission constraints than those specified); and (3) cost-based unit commitment and dispatch (*i.e.*, not taking into account any bid adders that market participants may be able to apply in their offers). The simulations (consistent with the simulated day-ahead market construct) do not take into account the impacts of load forecasting errors, unplanned generation and transmission outages, or the uncertainty of renewable generation outputs.

With these caveats, it is nevertheless important to understand that production cost models are powerful tools: they jointly simulate generation dispatch and power flows to capture the actual physical characteristics of both generating plants and the transmission grid, including the complex dynamics between generation and transmission availability, energy production and operating, and load following requirements. These types of simulations provide valuable insights to both the operations and economics of the wholesale electric system in the entire interconnected region. This is evident in that production cost models are used by every ISO and RTO for transmission planning purposes. Production cost models are used by many utilities and regulators for resource planning and to evaluate the implications of policy decisions and market uncertainties.

3. Data Release to Stakeholders

Throughout the stakeholder process, and prior to publishing this report, a significant amount of data was made available for public review. The data includes a comprehensive set of detailed input files to our production cost model, various summaries of our assumptions and results, replications of many of the demonstratives contained herein, and live calculations of our final metrics on system-wide production costs; California net production, purchases, and sales cost; and CO_2 emissions.

Some files are available for immediate view on www.caiso.com, and others are available through a non-disclosure agreement with CAISO.[7] The confidentiality designation is used for files containing: (a) data that is considered Critical Energy Infrastructure Information under federal law; (b) hourly or unit-level input data—or any data that could be used to derive those inputs—that was originally developed by CAISO and/or WECC stakeholders under confidentiality restrictions in other transmission planning studies or non-disclosure agreements; and/or (c) proprietary data or information. (Please contact regionalintegration@caiso.com to request access to confidential data files.)

In addition to the data release the study team responded to a large number of formal and informal comments and questions from stakeholders. These materials can be found on www.caiso.com.[8]

B. MARKET FUNDAMENTALS AND KEY MODELING ASSUMPTIONS

1. Projected Demand for Electricity

Our outlook on future electricity demand in California, including the demand reductions from energy efficiency, retail-level demand response, and distributed generation, is developed based on CEC's 2016–2026 California Energy Demand forecast prepared for the 2015 Integrated Energy Policy Report.[9] This is the state's standard demand forecast used to support various planning efforts in California, including CPUC's 2016 Long-Term Procurement Plan ("LTPP") and CAISO's 2016–17 Transmission Planning Process. In the 2015 IEPR, the CEC identified five scenarios based on baseline demand levels and additional achievable energy efficiency ("AAEE") savings. For the purpose of our analyses, we selected CEC's "mid baseline" demand forecast with "mid

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7 Specifically, Brattle's public files can be viewed here: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1ED636CF-B394-407E-A646-B4CA0F01F65A. Last accessed in July 2016.

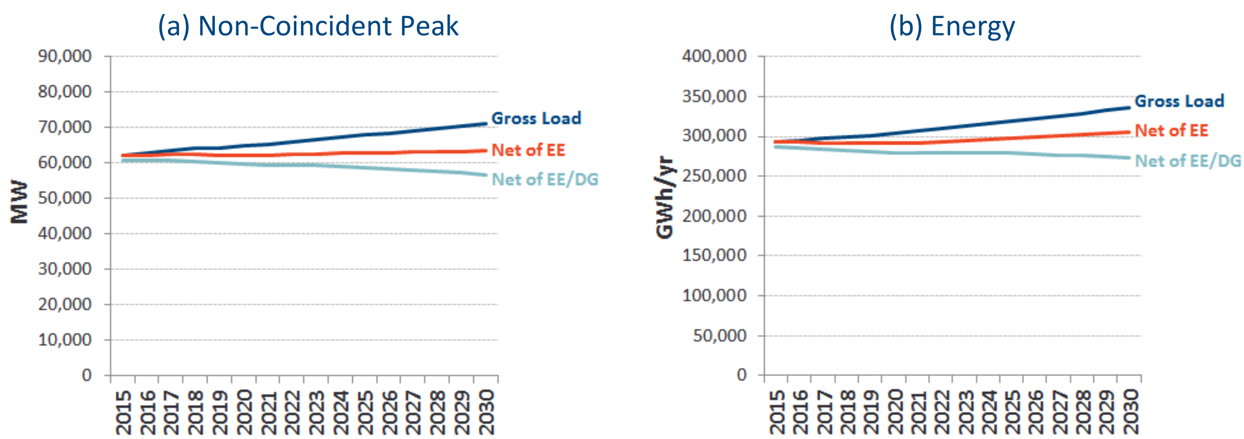
8 Specifically, these materials can be found here: https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx Last accessed in July 2016.

9 CEC, "California Energy Demand 2016-2026, Revised Electricity Forecast Volume 1: Statewide Electricity Demand and Energy Efficiency," January 2016, available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf

AAEE" savings scenario. This reflects expected demand under "normal" weather conditions.[10] The CEC's demand forecast includes assumptions on vehicle electrification and charging, demand response (including time-of-use retail rates), and behind-the-meter co-generation and photovoltaic solar facilities. More discussion of the components of the demand forecast can be found in Volume IV (Renewable Energy Portfolio Analysis) of the SB 350 study.

Figure 4 shows the assumed annual state-wide peak load and energy projections in California. In PSO, we used the load values net of energy efficiency savings (shown in red) and modeled incremental distributed solar resources (a portion of total distributed generation, or "DG") on the supply side. The CEC's demand forecast is available through 2026, after which we extrapolated the values by applying the CEC's long-term growth rates, assuming that AAEE savings continue to increase at the same pace. To develop hourly load inputs, we adjusted 2005 load shapes to match projected peak load and energy values for gross load, shifted data to align weekdays and weekends, and then subtracted the CEC's hourly forecast of AAEE savings.

Figure 4: California Annual Peak Load and Energy Projections



For other areas in WECC, the load assumptions are developed based on WECC's Loads and Resources (LAR) forecast. In our 2020 simulations, we relied on inputs from CAISO's 2015–16 TPP model. The model reflects the 2012 LAR forecast and adjustments that were implemented

[10] In other words, compared to historical weather patterns, and holding all else constant, the forecast is developed such that there is a 50% chance that actual weather will be more extreme (and annual peak loads be significantly higher) than projected and 50% chance that the weather will be less extreme. The value of market operations tends to be disproportionately higher during more challenging load conditions, including regional weather differences that can cause unusually high regional power flows and transmission constraints.

for pump loads and EE savings in the TEPPC model. For 2030, we incorporated the 2015 LAR forecast available through 2025, after which we extrapolated at the long-term growth rates. For hourly shapes, we scaled 2020 inputs in each load area to match projected energy levels and shifted data to align weekdays and weekends.

Figure 5 summarizes the annual peak load and energy assumptions in PSO for all of the regions modeled.

Figure 5: Summary of Projected Peak Load and Energy by Region

	Annual Energy (GWh)			Non-Coincident Peak (MW)		
Region	2020	2030	10-yr CAGR	2020	2030	10-yr CAGR
California	292,155	305,798	0.5%	62,222	64,472	0.4%
Northwest	248,531	276,857	1.1%	46,895	52,593	1.2%
Southwest	161,586	179,812	1.1%	34,395	38,563	1.2%
Rocky Mt	69,959	83,809	1.8%	13,386	15,925	1.8%
WECC non-U.S.	182,649	219,190	1.8%	28,901	34,548	1.8%
Total WECC	**954,880**	**1,065,466**	**1.1%**	**185,798**	**206,101**	**1.0%**

2. Projected Fuel Prices

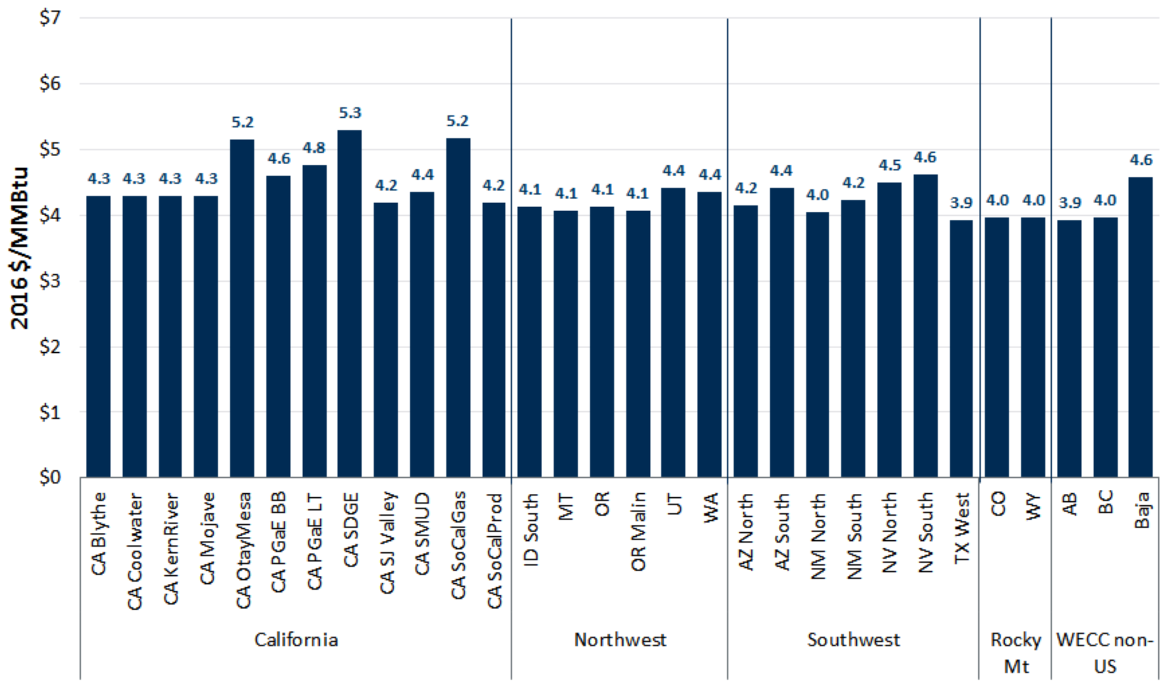
Fuel cost is a major component of the variable cost of generation and a key driver of electricity prices in California and WECC-wide. The variation of delivered fuel prices in the WECC can dictate which generating units would be utilized across the region and have a significant impact on market outcomes. Although electric generators in the WECC rely on a variety of fuels—as reflected in PSO—California's system relies most heavily on natural gas-fired plants. Electricity prices are therefore highly sensitive to variation in natural gas prices. At the same time, coal prices could affect the marginal cost of importing power from coal-fired plants located outside of California compared to running internal generators.

For natural gas, we relied on the CEC's forecast of monthly burner-tip prices under the "mid baseline" demand forecast published as part of the 2015 IEPR.[11] The CEC's forecast covers over 30

[11] CEC, "WECC Gas Hub Burner Tip Price Estimates using 2015 IEPR Natural Gas Estimates," January 2016, available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210495_20160222T143214_WECC_Gas_Hub_Burner_Tip_Price_Estimates_using_2015_IEPR_Natural.xls

hubs across the WECC for 2016–2026. For each of these hubs, the forecasted prices reflect average delivered prices for gas-fired generators including transportation charges to reflect the cost of moving natural gas from the basin to the generators.[12] In PSO, we mapped CEC's hubs to areas defined in the model. In our 2020 simulations, we developed the model inputs using CEC's forecast for that year. For 2030, we assumed that the prices grow at inflation after 2026 (constant in real $ terms). Figures 6 and 7 show the annual average burner-tip prices assumed in PSO for both study years.

Figure 6: Projected 2020 Natural Gas Prices



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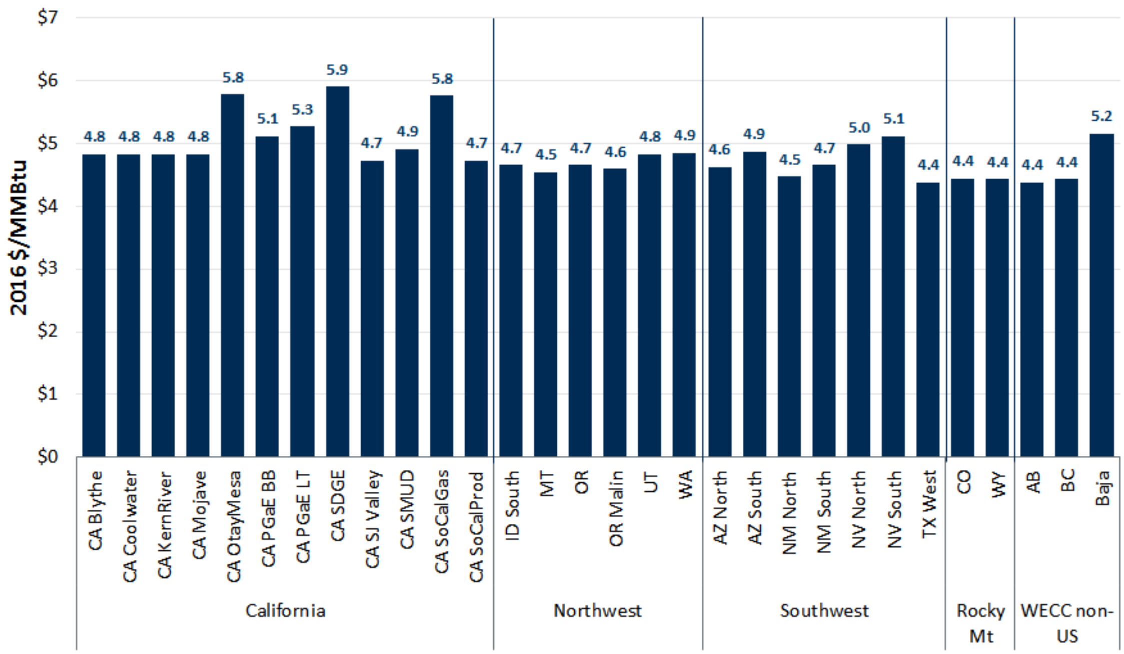
12 For details on CEC's methodology, please see Staff report "Estimating Natural Gas Burner Tip Prices for California and the Western United States", November 2014, available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-008

Figure 7: Projected 2030 Natural Gas Prices



Outside of California, coal-fired generators account for a large portion of the overall power supply even though the amount of coal generation continues to decline as a result of retirements. Accordingly, coal prices play a more prominent role in the formation of electricity prices and market outcome in the rest of the WECC region. As mentioned earlier, coal prices impact the relative economics of imports versus internal generation for California. Figure 8 summarizes the coal price inputs in our PSO simulations, which are consistent with CAISO's 2015–16 TPP model and the TEPPC model. For the purpose of our analysis, we assumed that the coal prices grow at inflation between 2020 and 2030 study years (*i.e.*, we hold the prices constant in real dollars).

Figure 8: Projected 2020 and 2030 Coal Prices

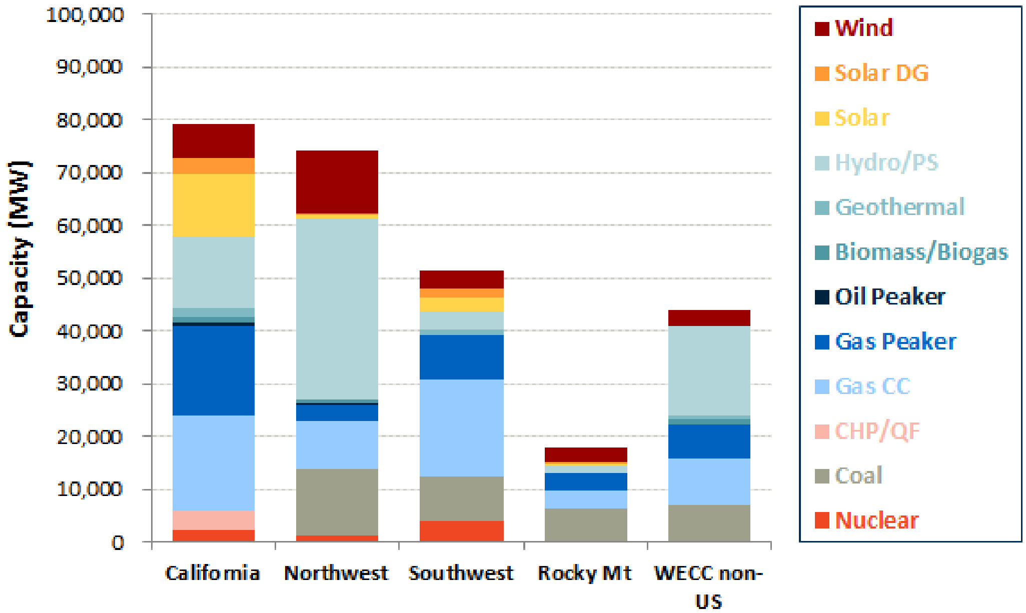
Coal Price Region	Price 2016$/MMBtu
Alberta	$1.57
Arizona	$2.50
California South	$1.83
Colorado East	$2.25
Colorado West	$2.24
Idaho	$1.22
Montana	$1.39
New Mexico	$2.30
Nevada	$3.26
Pacific Northwest	$2.73
Utah	$2.01
Wyoming East	$1.56
Wyoming Powder River Basin	$0.99
Wyoming Southwest	$2.16

For other fuel types (oil, bio fuels, uranium, *etc.*), PSO inputs are developed based on the same set of assumptions used in CAISO and TEPPC models assuming prices to grow at inflation between 2020 and 2030 (constant in real $). Prices of other fuel types play a more limited role in market outcome, because most of the generating units using these fuels either run all the time (except for outage hours) due to very low operating costs or they run very little as they have very high operating costs and would not be needed under weather normalized conditions simulated in PSO.

3. Supply of Electricity Generation Resources

The inputs associated with the generating resources modeled in the 2020 PSO simulations are developed based on CAISO's 2015–16 TPP model. The underlying data is consistent with TEPPC's model and updated by CAISO to incorporate the 33% RPS portfolio provided by CPUC in April 2015. In California and in the Northwest, hydroelectric generation is a major source of power production. CAISO's model assumes hydroelectric production based on 2005 production, which, overall for WECC, was an average year (although a relatively high year for California, and relatively low for the rest of WECC). We increased the amount of distributed solar assumed in the model based on the CEC's forecasts for 2015 IEPR. Figure 9 summarizes the overall capacity available in 2020, which is kept the same between the Current Practice and CAISO+PAC scenarios.

Figure 9: 2020 Generating Capacity Assumptions by Region and Type



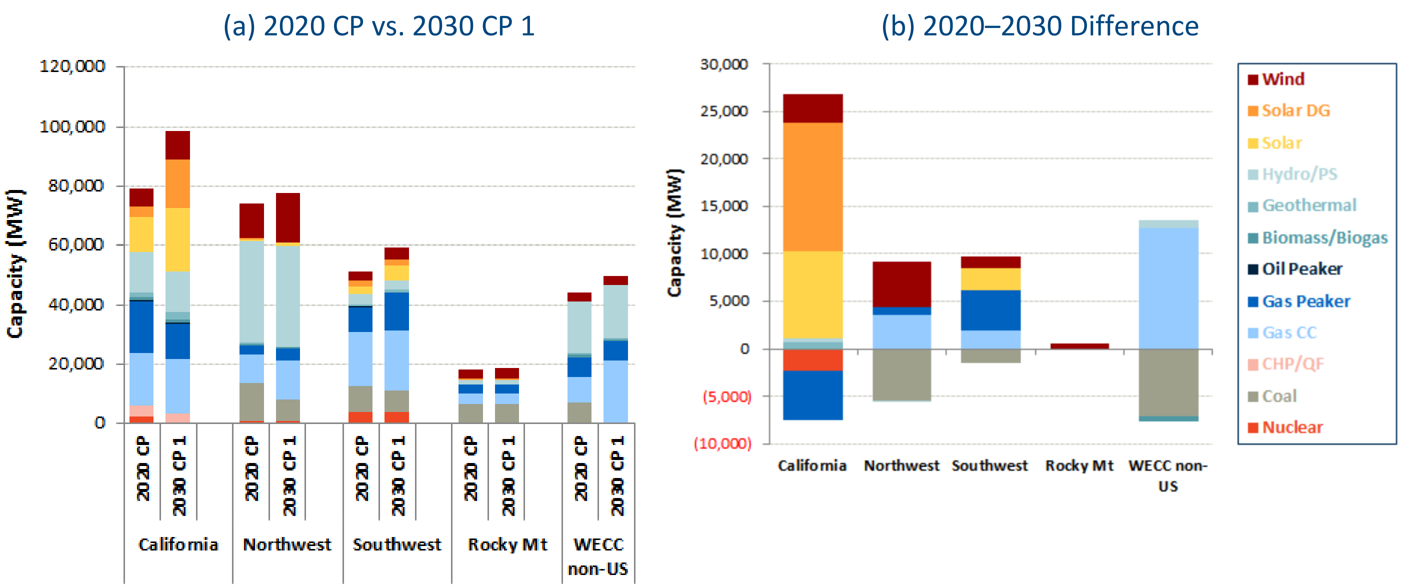
Note: The graphic reflects maximum capacity for renewable resources and summer capacity for conventional resources.

For 2030, we started with the same Gridview database and made further changes to the resource assumptions including:

1. Additional renewables to meet 50% RPS in California based on E3's Renewable Energy Portfolio Analysis (Volume IV of the SB 350 study);
2. Coal plant retirements and natural gas plant additions based on TEPPC 2024 assumptions plus utility resource plans and Brattle research;
3. RPS-related renewable generation additions in the rest of the U.S. WECC region based on the incremental need to meet 2030 targets, informed by utility resource plans; and,
4. Renewable additions facilitated by regional market that are beyond RPS requirements.

Figure 10 highlights the overall changes in capacity assumptions between 2020 and 2030 under the Current Practice scenario. In California, about 26 GW of renewables are added in 2030 Current Practice 1, most of which is utility-scale and distributed solar generation. There is about 5 GW of net reduction in natural gas-fired capacity, largely driven by the retirements associated with California's once-through-cooling ("OTC") requirements. In addition, we assumed the Diablo Canyon nuclear facility (2.3 GW) would be retired by 2030 based on CPUC's assumptions to the 2016 LTPP.[13] Outside of California, approximately 9 GW of renewables were added, of which around 6 GW is needed to meet California's RPS and the remaining 3 GW are needed to meet the RPS in other U.S. WECC states. Coal-fired capacity in the region is assumed to decrease by 14 GW, from 35 GW to 21 GW, which reflects the planned plant retirements in the original Gridview/TEPPC database supplemented by additionally announced retirement plans based on recent utility resource plans. Approximately 26 GW of natural gas-fired capacity is added (19 GW from combined-cycle plants and 7 GW from combustion turbines) to replace retiring coal capacity and meet increasing demand, consistent with the same Gridview/TEPPC database and additional announcements in recent utility resource plans.

Figure 10: Comparison of 2020 and 2030 Capacity Assumptions by Region and Type



Note: The graphics reflect maximum capacity for renewable resources and summer capacity for conventional resources.

The renewable resource assumptions vary across the 2030 scenarios based on E3's portfolios to meet 50% RPS in California and the additional RPS renewables (beyond RPS mandates) assumed to be facilitated by the regional market in the WECC.

Figure 11 compares the capacity levels assumed in the 2030 simulations under the Current Practice 1, Regional 2, and Regional 3 Scenarios. Accordingly:

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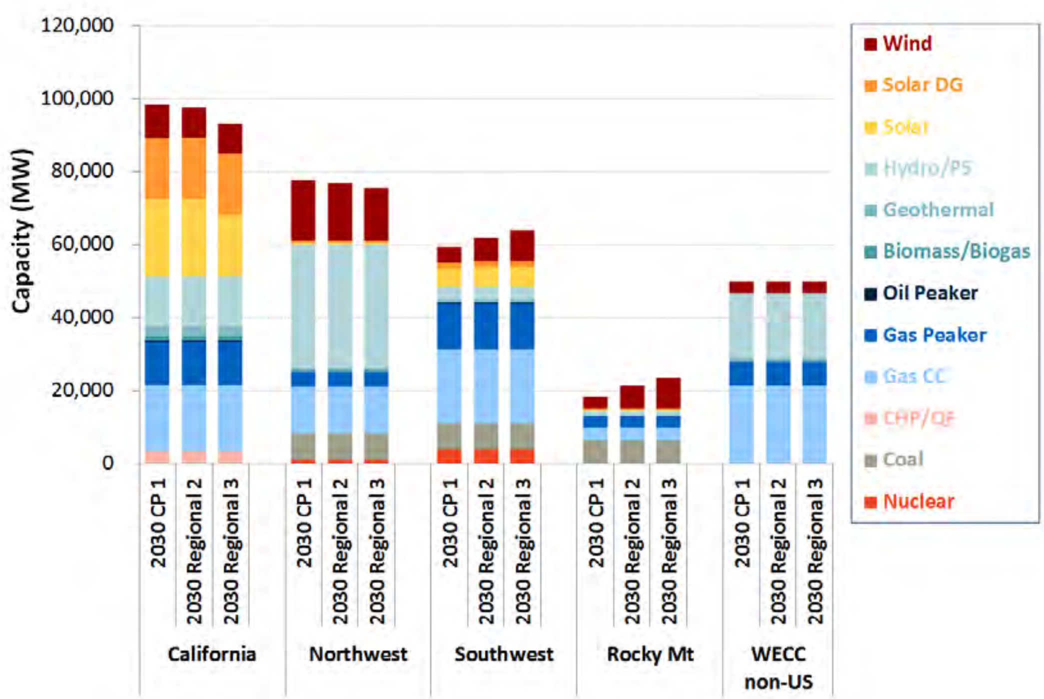
13 Pacific Gas & Electric Company has announced that they will retire Diablo Canyon by the end of its existing nuclear operating license in 2024.

- The Current Practice 1 Scenario (previously referred to as case "1A") includes the highest amount of in-state renewables across the three scenarios analyzed.
- The Regional 2 Scenario has approximately 0.9 GW less in-state renewable capacity compared to Current Practice 1, as a result of reduced curtailments and "over-build" of renewable capacity to make up for curtailed energy.
- The Regional 3 Scenario assumes that California would procure more out-of-state renewables, with around 2.5 GW of increased capacity from wind plants located outside of California and 4–5 GW less capacity from solar plants in California.
- Both of the Regional ISO scenarios include 5 GW of additional capacity from wind resources that are assumed to be facilitated by the regional market beyond RPS mandates. (See Volume XI for discussion of experience with beyond RPS renewable generation investments.) Of this capacity, 3 GW is assumed to be located in Wyoming and 2 GW in New Mexico.

Figure 11: Comparison of 2030 Capacity Assumptions in Various Scenarios



Note: The graphics reflect maximum capacity for renewable resources and summer capacity for conventional resources.

For each of the new renewable resources, we identified an hourly schedule available in the Gridview database and determined the appropriate scaling factors to match the energy levels estimated in E3's analysis. We determined the locations of the resources in California consistent with the designations of Competitive Renewable Energy Zones ("CREZ"). For out-of-state resources, we utilized the Western Energy Renewable Zones ("WREZ") as a guide to identify high-potential areas. We placed the utility-scale wind and solar plants on high-voltage systems to avoid any unrealistic levels of curtailments due to local congestion. We assumed that the distributed solar resources would be spread across each corresponding load area.

Operational characteristics of the units in the PSO model are based on CAISO's 2015–16 TPP model. We updated ramp rates, minimum load assumptions, and must-run designations of certain units in PSO to better characterize units' flexibility and their ability to provide reserves. Figure 12 summarizes the average unit characteristics for the thermal generators included in the PSO model.

Figure 12: Summary of Unit Characteristics by Type

	2020 Summer Capacity (MW)	2030 Summer Capacity (MW)	Min Load (% of capacity)	Min Up Time (Hours)	Min Down Time (Hours)	Fully Loaded Heat Rate (Btu/kWh)	Forced Outage Rate (%)	Ramp Rate (MW/min)	Startup Cost ($/MW)	Variable O&M Cost ($/MWh)
Biomass/Biogas	2,797	2,245	62%	9.4	6.3	12,341	3.2%	0.7	$6	$1.8
Coal	34,708	20,708	43%	166.6	47.7	9,825	3.1%	4.8	$157	$2.9
Gas CC	57,742	76,002	52%	7.7	4.2	7,677	2.6%	13.5	$73	$1.1
Gas Peaker	38,255	38,171	11%	3.3	2.7	8,473	1.3%	13.2	$82	$0.9
Gas CHP/QF	3,435	3,435	100%	6.0	3.7	10,614	2.0%	8.9	$105	$0.8
Geothermal	3,493	4,202	73%	11.0	4.9	N/A	5.1%	1.5	$0	$2.3
Nuclear	7,367	5,067	100%	168.0	168.0	11,000	0.3%	4.3	$124	$5.3
Oil Peaker	802	802	11%	2.0	1.9	12,240	2.8%	4.9	$73	$1.5

Note: Values reflect capacity-weighted averages. Unit-specific inputs vary.

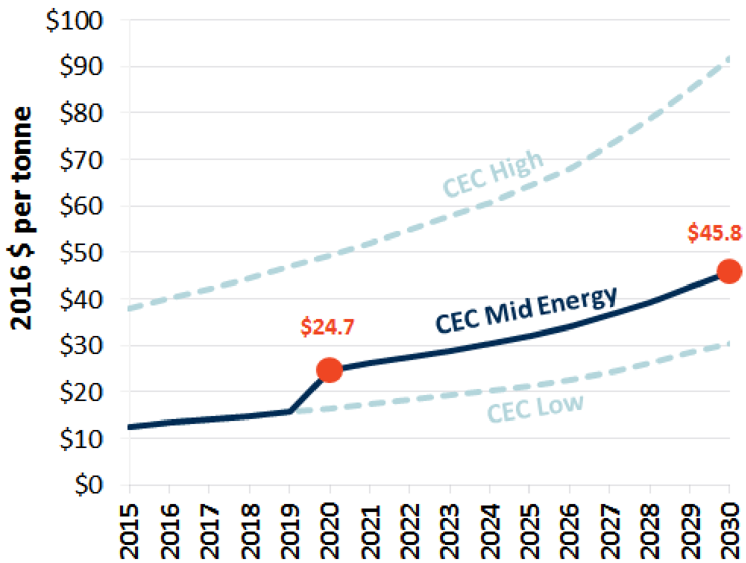
4. Greenhouse Gas Emission Prices

California Assembly Bill 32 ("AB 32") requires in-state electric generators to operate within a cap-and-trade market for GHG emissions. In PSO, we simulated the impact of AB 32 on the electric sector by imposing a CO_2 cost on emitting units in California and imports into the state. Our methodology for determining the CO_2 costs in the PSO model is consistent with the methodology used in the CAISO's 2015–16 TPP model. For the CO_2 prices in PSO, we relied on the CEC's projections published as part of the 2015 IEPR (revised in December 2015).[14] Figure 13 shows the CO_2 prices we used in our 2020 and 2030 simulations, along with CEC's projections under three

14 CEC, "2015 IEPR Carbon Price Projections Assumptions," February, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN208931_20160125T073329_2015_IEPR_Final_GHG_Cost_Projection.xlsx

different scenarios. To be internally consistent with our load and gas price assumptions, which are from the same CEC forecast, we selected the CO_2 prices developed under the "mid baseline " demand scenario, with $24.7/tonne in 2020 increasing to $45.8/tonne in 2030 (2016 dollars).

Figure 13: Projected California CO_2 Prices under AB 32



In the PSO model, the CO_2 cost adders for generating units in California are determined based on units' CO_2 emission rates. Imports from units under power purchasing agreements ("PPAs") with California entities are treated the same way as in-state generators, facing unit-specific CO_2 costs for the portion of their output contracted to California. All other market imports into California that are not assigned to any specific generators are assumed to be subject to "generic" CO_2 hurdle, consistent with the methodology applied in the CAISO and TEPPC models. Accordingly, market imports into California (except from BPA) face a CO_2 hurdle adder calculated based on the average emission rate of a gas-fired combined-cycle plant (0.435 tonnes/MWh). The CO_2 hurdle on imports from BPA is implemented in two tiers: (a) "Tier 1" rate is set at 0.019 tonnes/MWh for imported energy from BPA's excess hydro generation, with the excess amounts defined at a monthly level in the BPA White Book,[15] and (b) "Tier 2" rate is set to 0.435 tonnes/MWh for any incremental imports above the Tier 1 limits.

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15 "2011 Pacific Northwest Loads and Resources Study, Technical Appendix, Vol. 1, Energy Analysis," BPA, May 2011, Table A-30, p. 151, available at: http://www.bpa.gov/power/pgp/whitebook/2011/WhiteBook2011_TechnicalAppendix_Vol%201_Final.pdf

The baseline scenarios assume no CO_2 price for outside of California. We evaluated a sensitivity that assumes a $15/tonne of CO_2 price in the rest of U.S. WECC as a proxy to demonstrate the region's compliance with the EPA's Clean Power Plan, recognizing that carbon cost under CPP will likely be lower than under AB 32. The results of this sensitivity are discussed in Section C.2.e.

5. Hurdle Rates

Generator operations and energy transfers between regions are subject to economic and transactional barriers, modeled as "hurdle rates" in PSO. These hurdle rates include representations of bilateral trading transaction costs, wheeling and other transmission-related charges between balancing authorities, and GHG charges for emissions associated with energy imports into California.

Wheeling charges, shown in the second column of Figure 14, are transmission fees based on regulated Open Access Transmission Tariffs that transmission owners would receive for the use of their transmission system for the purpose of exporting energy.[16] In the model, the wheeling rate for CAISO is assumed to be $11.5/MWh (in 2016 dollars) based on CAISO's recent projection of transmission access charges (TAC).[17] Wheeling charges for other balancing authorities are determined based on Schedule 8 of OATTs and other public data on transmission rates available as of February 2016. We conservatively used off-peak rates, which in some cases are $0.5-$5.5/MWh lower compared to on-peak rates.

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16 The wheeling charges shown in the figure are directional and, consistent with regulatory requirements, they are applied only to exports from a transmission system (typically the Balancing Authority). For example, power exported from EPE to PNM would be scheduled on a (one-directional) contracted path from EPE to PNM and charged at the EPE wheeling-out rate ($3.2/MWh), whereas power exported from PNM to EPE would be scheduled on a one-directional contracted path from PNM to EPE and charged at the PNM wheeling-out rate ($6.0/MWh). These directional wheeling rates apply both to "wheeling out" and "wheeling through" schedules. If an energy delivery schedule of wheeling out and wheeling through requires multiple transmission systems, these charges would be additive (often referred to as "pancaked").

17 WECC, "Transmission Wheeling Rates," November 2015, available at:
https://www.wecc.biz/Administrative/151124%20TAS-DWG%20-%20Transmission%20Wheeling%20Rates%20-%20XBWang1.pdf
https://www.wecc.biz/Administrative/151124%20TAS-DWG%20-%20Transmission%20Wheeling%20Rates%20-%20XBWang.xlsx

Other "hurdle" rates include: $1/MWh for the administrative transmission tariff charges, $1/MWh for bilateral trading margins, and $4/MWh for additional market friction in the unit commitment cycle. The $1/MWh administrative charges reflects the average level of various tariff-based surcharges (for scheduling, system control, reactive power, regulation, and operating reserves) that are imposed by balancing areas in addition to the main charge for transmission service. The $1/MWh trading margin is a conservative estimate of bilateral transactions costs and trading margins that need to be achieved before a bilateral transaction will take place. Experience with production cost simulations from around the country shows that changes to generation unit commitment face a higher hurdle rate. Industry experience with these types of market simulations has shown that the assumed differential ($1/MWh for dispatch and $5/MWh for unit commitment) yields realistic results.

GHG charges applied to California imports as a part of the hurdle rate are determined by two factors: the GHG prices applied on a unit-specific basis to plants in California (or contracted to supply California) and the "generic" emission rate assumed for unspecified import sources as discussed earlier in Section 4.

Figure 14 summarizes the hurdle rate assumptions for the Current Practice scenarios. They vary by exporting region, and range from $7 to $18/MWh for unit commitment and $3 to $14/MWh for economic dispatch. These hurdle rates are assumed to grow by inflation over time (*i.e.*, we hold them constant in real dollars). In addition to the values shown in Figure 14, the imports into California from unspecified resources are subject to GHG charges of approximately $11/MWh in 2020 and $20/MWh in 2030 (except for imports from BPA's hydro).

Figure 14: Summary of Hurdle Rate Assumptions (2016 $/MWh)

Balancing Authority	OATT Wheel-Out Charge	Administrative Charge	Trading Margin (Commitment & Dispatch)	Additional Market Friction (Commitment Only)	Commitment Hurdle	Dispatch Hurdle
AESO	$5.2	$1.0	$1.0	$4.1	**$11.3**	**$7.2**
AVA	$5.8	$1.0	$1.0	$4.1	**$11.9**	**$7.8**
AZPS	$4.1	$1.0	$1.0	$4.1	**$10.3**	**$6.2**
BANC	$2.1	$1.0	$1.0	$4.1	**$8.2**	**$4.1**
BCHA	$5.4	$1.0	$1.0	$4.1	**$11.6**	**$7.5**
BPA	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
CAISO	$11.5	$1.0	$1.0	$4.1	**$17.6**	**$13.5**
CFE	$12.2	$1.0	$1.0	$4.1	**$18.3**	**$14.2**
CHPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
DOPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
EPE	$3.2	$1.0	$1.0	$4.1	**$9.3**	**$5.2**
GCPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
IID	$1.0	$1.0	$1.0	$4.1	**$7.1**	**$3.0**
IPCO	$2.7	$1.0	$1.0	$4.1	**$8.8**	**$4.7**
LDWP	$5.1	$1.0	$1.0	$4.1	**$11.3**	**$7.2**
NEVP	$3.8	$1.0	$1.0	$4.1	**$9.9**	**$5.8**
NWMT	$4.3	$1.0	$1.0	$4.1	**$10.5**	**$6.4**
PACE	$3.3	$1.0	$1.0	$4.1	**$9.4**	**$5.3**
PACW	$3.3	$1.0	$1.0	$4.1	**$9.4**	**$5.3**
PGE	$0.7	$1.0	$1.0	$4.1	**$6.9**	**$2.8**
PNM	$6.0	$1.0	$1.0	$4.1	**$12.2**	**$8.1**
PSCO	$4.6	$1.0	$1.0	$4.1	**$10.8**	**$6.7**
PSEI	$2.5	$1.0	$1.0	$4.1	**$8.6**	**$4.5**
SCL	$1.1	$1.0	$1.0	$4.1	**$7.3**	**$3.2**
SPPC	$3.8	$1.0	$1.0	$4.1	**$9.9**	**$5.8**
SRP	$2.2	$1.0	$1.0	$4.1	**$8.4**	**$4.3**
TEPC	$3.1	$1.0	$1.0	$4.1	**$9.2**	**$5.2**
TIDC	$2.5	$1.0	$1.0	$4.1	**$8.7**	**$4.6**
TPWR	$3.0	$1.0	$1.0	$4.1	**$9.1**	**$5.0**
WACM	$5.4	$1.0	$1.0	$4.1	**$11.6**	**$7.5**
WALC	$2.2	$1.0	$1.0	$4.1	**$8.4**	**$4.3**
WAUW	$4.0	$1.0	$1.0	$4.1	**$10.1**	**$6.0**

For the regional market scenarios, the hurdle rates within the regional footprint are removed (except for the GHG charges for imports into California) as follows:

- Under the 2020 CAISO+PAC scenario, the de-pancaked scheduled hourly flows between CAISO and PAC are assumed to be limited to the contractually-arranged transfer capability between the two regions allowing for hurdle-free transfers up to 776 MW from CAISO to PAC and 982 MW from PAC to CAISO.

- The 2030 Regional ISO scenarios (both Regional 2 and Regional 3) are based on an integrated market model where transfers between the subregions of the contiguous portion of the regional entity are limited by the physical path ratings (instead of contract-path concepts) within the region and neighboring regions. Accordingly, wheeling and other transmission-related portions of the hurdle rates between all entities within the regional market (U.S. WECC without PMAs) are set to zero.

6. CAISO Net Export Limit

As California approaches meeting its 50% RPS requirement and its installed capacity of intermittent resources increases considerably, the ability of neighboring regions to absorb CAISO's surplus intermittent energy will likely be limited due to insufficient flexibility in bilateral markets. To represent this, we enforced a limit on CAISO's ability to export surplus intermittent energy to other markets on a day-ahead basis. In the Current Practice 1 scenario, we set this limit at 2,000 MW and apply it to the simultaneous re-export/sale of all intermittent resources procured by load-serving entities in the CAISO, including out-of-state resources that are dynamically scheduled into the CAISO market.[18] This means it is assumed that bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus the export/sale of an additional 2,000 MW of (mostly intermittent) California-contracted renewable resources.

In the Regional 2 and Regional 3 scenarios, as a result of centralized unit commitment and dispatch, we assumed that the external markets ability to absorb intermittent energy from CAISO is constrained only by the system's physical limitations. To capture this, we raised CAISO's net export limit to 8,000 MW as a proxy for a physical simultaneous transfer limit, which has not yet been specified within the WECC path rating process.

In addition, we ran a sensitivity (Current Practice 1B) assuming higher flexibility of bilateral markets to absorb CAISO's surplus renewable energy during oversupply conditions. In this sensitivity, we increased the CAISO bilateral net export capability from 2,000 MW to 8,000 MW. This high-bilateral-flexibility case assumes that bilateral markets would accommodate the re-

[18] But for existing renewables and REC-only purchases, all additional out-of-state renewable resources procured to meet the 50% RPS are subject to this bilateral limit because, in the Current Practices scenarios, this limit represents the ability of western bilateral markets to absorb surplus renewables (as opposed to the physical CAISO export limit simulated in the regional market scenarios).

export of all prevailing existing imports (ranging from 3,000 to 4,000 MW per hour) plus the export/sale of an additional 8,000 MW of (mostly intermittent) California-contracted renewable resources. The results of this sensitivity are discussed in Section C.2.b.

7. Operating Reserve Requirements

Operating reserves are procured in the energy market to ensure reliable operations, and accommodate variability and uncertainty in the power system (*e.g.*, from load, renewable output, generation or transmission outages). Operating reserves typically include: *spinning and non-spinning reserves* that would be needed in response to system outages (referred to as "contingency reserves"), and *regulation reserves* using automatic generation control to balance supply and demand within the shortest applicable dispatch intervals. Increasing uncertainty driven by renewable additions in many markets has led to the exploration of additional reserve types, such as *load-following reserves* to accommodate intra-hour forecast errors and ramping needs, and *frequency response reserves* to maintain system frequency near the nominal 60 Hz and dynamically respond to large system disturbances during the initial period (from a few seconds to a minute).

The simulation of these products requires that the model sets aside part of the generating units capacity in "standby" mode, ready to provide more or less energy within a short timeframe (typically between 5 and 30 minutes) as allowed by the specified ramping rates. Figure 15 summarizes various reserve types considered in our PSO simulations.

Figure 15: Operating Reserve Types

Reserve Type	Up/Down	Description/Modeling Approach
Spin	Up	Online capacity available within 10 minutes
Non-Spin	Up	Not modeled
Regulation	Up/Down	Additional online capacity available within 5 minutes
Load-Following	Up/Down	Additional online capacity available within 15 minutes
Frequency Response	Up	Additional online capacity reserved to respond to contingency-driven frequency deviations

The rest of this section describes each of the reserve types modeled in PSO, with details on how reserve requirements are defined in the simulations and which generating resources contribute towards meeting the reserve levels that are required.

a. Spinning Reserves

In the PSO model, we applied the spinning reserve requirements at multiple levels within individual balancing areas and reserve sharing groups. Figure 16 summarizes the requirements and hierarchy of sharing arrangements assumed in our simulations.

In the Current Practice scenarios, we used the same reserve sharing arrangements as the TEPPC model and the CAISO's 2015–16 TPP model. We set the spin requirements to be equal to 3% of load (determined hourly) in the primary reserve sharing groups and in areas that are not part of a sharing group consistent with the WECC requirements of BAL-002-WECC-2.[19] Within the Northwest, each area is required to hold at least 25% of its requirement locally, which is equal to 0.75% of their individual load. In the Southwest and the Rockies the local requirements are assumed to be higher, at 90% of the total requirement (2.7% of load).

In the CAISO+PAC and Regional ISO scenarios, we expanded and combined the reserve sharing groups assuming the sharing arrangements that exist under the Current Practice scenarios would continue to exist within a regional market in addition to the new sharing arrangements that would emerge as a result of regionalization.

- Under the 2020 CAISO+PAC scenario, we assumed that CAISO and Northwest group (which PAC is a part of) would merge and create a larger primary sharing group subject to a 3% spin requirement. Within this larger group, CAISO and PAC would form a sub-group, which is required to set aside enough spin capacity to meet at least 0.75% of their combined load. The spinning reserve requirements in other areas (including local requirements within the Northwest) are kept the same as in the 2020 Current Practice scenario.
- Under the 2030 scenarios Regional 2 and Regional 3, we assumed that the reserve groups would combine to allow sharing within the regional market, which leads to a primary sharing group for the entire U.S. WECC. The PMAs are included in this larger group to maintain their existing reserve sharing arrangements. The assumptions for balancing areas

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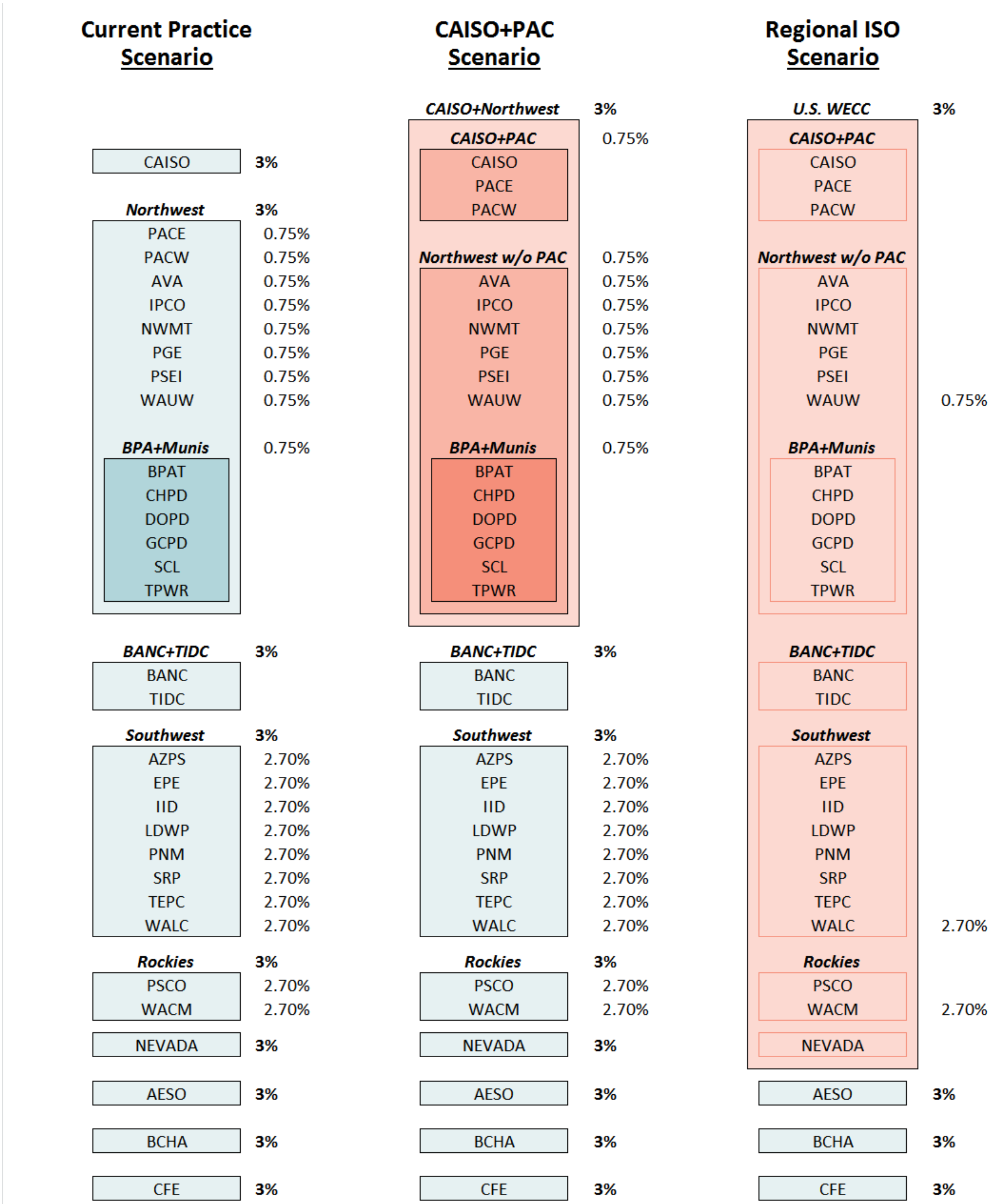
[19] The additional 3% non-spin or contingency reserve requirement is not explicitly simulated because sufficient non-operating capacity is available in the model to satisfy that requirement.

that are outside of the U.S. WECC are kept the same as in 2030 Current Practice 1 scenario.

Figure 16: Summary of Spinning Reserve Requirements and Sharing Arrangements



b. Regulation and Load-Following Reserves

The regulation and load-following reserve requirements assumed in the PSO simulations are developed based on an analysis by ABB. ABB implemented methodologies developed by the U.S. Department of Energy's National Renewable Energy Laboratory ("NREL"), which takes into account hourly load and renewable generation levels, uncertainty over a particular time frame, and specified confidence intervals to derive the amount of resources needed to be set aside. [20, 21, 22]

The uncertainty in net load is characterized as a function of the forecast errors for load, wind, and solar for each of the balancing area modeled:

- Load forecast errors are assumed to be 3% of load at the hourly timescale.
- Wind forecast errors are calculated based on hourly generation schedules developed for the PSO simulations (based on TEPPC shapes) assuming that the wind power output at a given time step would be used to predict the output for the next time step. The 95% confidence intervals are estimated to capture the relationship between wind generation levels and forecast errors for both the upward and downward directions.
- Solar forecast errors are calculated based on hourly generation schedules developed for the PSO simulations. The predictable portions of these generation schedules under "clear-sky" weather are used to capture the effects of clouds in calculating forecasts and forecast errors. The forecasted solar power output is defined as the actual output in the prior time step plus the expected change based on clear-sky data, which is then adjusted for the effects of clouds. The 95% confidence intervals are estimated to capture the relationship across solar generation levels, time of day, and forecast errors in the upward and downward directions.

Assuming that the uncertainty in load, wind output, and solar output are independent of each other, the forecast error in net load is calculated as the square root of the sum of the squares of the

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20 E. Ela, M. Milligan, B. Kirby, "Operating reserves and variable generation," NREL, August 2011. http://www.nrel.gov/docs/fy11osti/51978.pdf

21 E. Ibanez, G. Brinkman, M. Hummon, and D. Lew, "A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis," NREL, August 2012. http://www.nrel.gov/docs/fy12osti/56169.pdf

22 E. Ela, B. Kirby, E. Lannoye, M. Milligan, D. Flynn, B. Zavadil, and M. O'Malley, "Evolution of Operating Reserve Determination in Wind Power Integration Studies," NREL, March 2011. http://www.nrel.gov/docs/fy11osti/49100.pdf

forecast errors for gross load, wind, and solar. The calculations are done on an hourly basis for each of the balancing areas, and used to determine the load-following reserve requirements in each area.

The regulation requirements are estimated based on an analysis similar to that done for load-following, but under a 5-minute timescale. To generate data for 5-minute intervals, the hourly values are interpolated and then random noise is added assuming normal distribution of forecast errors consistent with the statistics on hourly data. For load, the forecast errors are assumed to be equal to 1% of load based on the NREL study.[23] The overall regulation reserve requirements are calculated as the square root of the sum of the squares of the 5-minute forecast errors for gross load, wind, and solar.

In order to develop inputs used in PSO simulations, we made several modifications to the hourly results from ABB's analysis. First, we computed the average values for each month and hour of the day to get reasonable reserve requirements that can be used under multiple scenarios with different renewable assumptions. Then, we eliminated unrealistic spikes caused by data limitations. Finally, we adjusted the requirements to account for the ramping of net load during the sunrise and sunset periods, by setting load-following requirements to be greater than or equal to 20-minute ramp, and regulation requirements to be greater than or equal to 5-minute ramp.

Figure 17 illustrates the load and renewable profiles and the final load-following and regulation requirements estimated for CAISO in 2030.

Under the Current Practice scenarios we enforced the load-following and regulation reserve requirements at the balancing area level. With regionalization, we allowed reserve sharing in the regional market. Due to increased diversity of load and renewables across a wider geographic footprint, the total amount of reserves needed in the Regional ISO scenarios are estimated to be lower compared to the sum of the individual requirements modeled under the Current Practice scenarios.

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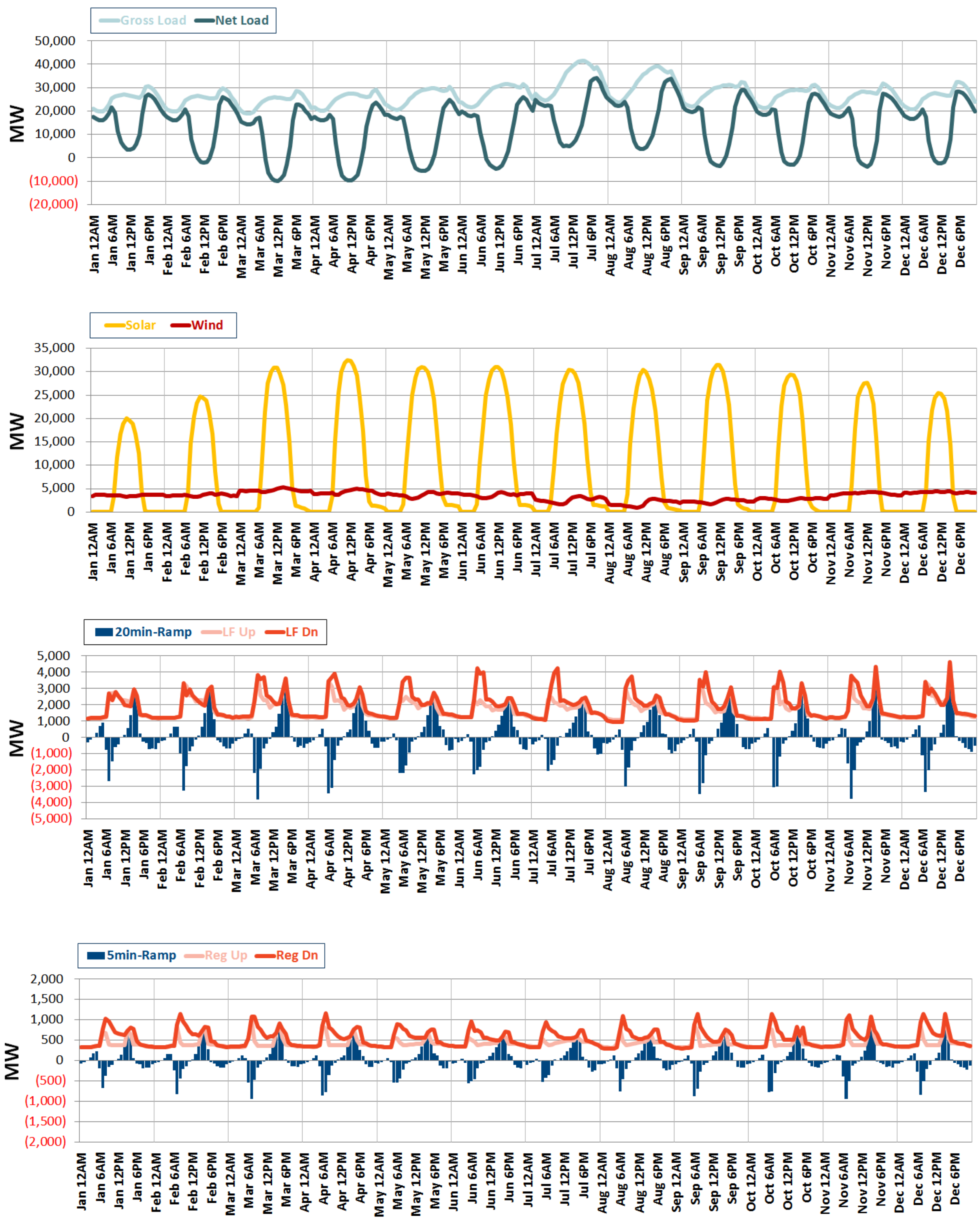
23 *Id.*

Figure 17: Illustration of Average Load, Renewables, and Reserve Profiles in CAISO

(2030, by Month and Hour of Day)



Figures 18 and 19 summarize aggregate annual and peak requirements assumed in our market simulations. In 2030, the regional market is estimated to reduce load-following and regulation requirements by around 20–25%, which contributes to more efficient dispatch of resources and lower costs (since less resources are needed to be set aside for operating reserves).

Figure 18: Summary of Load-Following Requirements
(a) Annual GWh/yr

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn
CAISO	10,277	10,524	-	-	-	-	15,376	16,849	-	-
PAC	3,091	3,167	-	-	-	-	3,265	3,319	-	-
CAISO + PAC	**13,368**	**13,691**	**11,989**	**12,325**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(1,379)	(1,366)	-	-	-	-	-	-
			(10.3%)	(10.0%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	15,495	15,330	15,495	15,330	-	-	17,338	17,371	-	-
U.S. WECC without PMAs	**28,863**	**29,021**	**27,484**	**27,655**	**22,344**	**22,585**	**35,980**	**37,539**	**27,009**	**28,562**
Impact of regionalization					(6,519)	(6,436)			(8,971)	(8,977)
					(22.6%)	(22.2%)			(24.9%)	(23.9%)
PMAs	5,285	5,167	5,285	5,167	5,285	5,167	5,621	5,506	5,621	5,506
WECC (non-U.S.)	6,093	6,098	6,093	6,098	6,093	6,098	7,103	7,147	7,103	7,147
WECC Total	**40,242**	**40,287**	**38,863**	**38,921**	**33,723**	**33,850**	**48,704**	**50,192**	**39,733**	**41,215**

(b) Non-Coincident Peak MW

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn
CAISO	2,147	2,114	-	-	-	-	4,601	4,601	-	-
PAC	516	513	-	-	-	-	605	605	-	-
CAISO + PAC	**2,664**	**2,627**	**2,586**	**2,586**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(78)	(41)	-	-	-	-	-	-
			(2.9%)	(1.6%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	2,725	2,740	2,725	2,740	-	-	3,315	3,444	-	-
U.S. WECC without PMAs	**5,389**	**5,366**	**5,311**	**5,325**	**3,774**	**3,774**	**8,521**	**8,650**	**6,858**	**6,858**
Impact of regionalization					(1,615)	(1,593)			(1,663)	(1,791)
					(30.0%)	(29.7%)			(19.5%)	(20.7%)
PMAs	846	778	846	778	846	778	896	827	896	827
WECC (non-U.S.)	899	921	899	921	899	921	1,054	1,141	1,054	1,141
WECC Total	**7,134**	**7,065**	**7,056**	**7,024**	**5,519**	**5,472**	**10,471**	**10,617**	**8,808**	**8,826**

Figure 19: Summary of Regulation Requirements
(a) Annual GWh/yr

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn
CAISO	3,094	3,163	-	-	-	-	3,774	4,796	-	-
PAC	933	936	-	-	-	-	949	992	-	-
CAISO + PAC	**4,027**	**4,099**	**3,690**	**3,782**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(337)	(317)	-	-	-	-	-	-
			(8.4%)	(7.7%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	4,771	4,663	4,771	4,663	-	-	5,141	5,357	-	-
U.S. WECC without PMAs	**8,798**	**8,762**	**8,461**	**8,445**	**7,223**	**7,269**	**9,864**	**11,146**	**7,976**	**8,832**
Impact of regionalization					(1,575)	(1,493)			(1,888)	(2,314)
					(17.9%)	(17.0%)			(19.1%)	(20.8%)
PMAs	1,545	1,515	1,545	1,515	1,545	1,515	1,637	1,634	1,637	1,634
WECC (non-U.S.)	1,964	1,961	1,964	1,961	1,964	1,961	2,317	2,314	2,317	2,314
WECC Total	**12,307**	**12,237**	**11,970**	**11,920**	**10,732**	**10,744**	**13,818**	**15,094**	**11,929**	**12,780**

(b) Non-Coincident Peak MW

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn
CAISO	589	586	-	-	-	-	1,150	1,159	-	-
PAC	148	138	-	-	-	-	151	151	-	-
CAISO + PAC	**737**	**724**	**660**	**654**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(76)	(70)	-	-	-	-	-	-
			(10.4%)	(9.7%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	808	786	808	786	-	-	902	934	-	-
U.S. WECC without PMAs	**1,545**	**1,510**	**1,468**	**1,440**	**1,154**	**1,147**	**2,203**	**2,244**	**1,715**	**1,715**
Impact of regionalization					(391)	(363)			(489)	(529)
					(25.3%)	(24.0%)			(22.2%)	(23.6%)
PMAs	238	223	238	223	238	223	246	257	246	257
WECC (non-U.S.)	281	284	281	284	281	284	332	332	332	332
WECC Total	**2,065**	**2,016**	**1,988**	**1,946**	**1,674**	**1,654**	**2,781**	**2,833**	**2,292**	**2,304**

c. Frequency Response Requirements

Under NERC's frequency response standard (BAL-003-1), beginning December 1, 2016, each of the Balancing Authorities will need to demonstrate that they have sufficient resources to quickly respond to disturbances in system frequency. The requirements modeled in PSO are developed based on inputs from CAISO staff. In its 2015 study, NERC estimated WECC-wide frequency response obligations to be 2,505 MW (net of credits for load resources) based on the simultaneous outage of two nuclear units at Palo Verde.[24] CAISO's share of the requirement is expected to be 752 MW, consistent with the draft proposal that CAISO published in February 2016.[25] The rest of the requirement (1,753 MW) is allocated to other Balancing Authorities in the WECC according to their load shares. In each Balancing Authority, we assumed that a portion of the requirement can be met by hydro and other renewable resources. Only the remaining portion to be met by natural gas-fired combined-cycle plants (CCs), coal plants, and storage facilities is modeled explicitly. Accordingly in CAISO, only 50% of the 752 MW is enforced in the simulations, consistent with the methodology that CAISO proposed for the 2016 LTPP study.[26] In other Balancing Authority areas, we determined the shares of the requirements met by renewables vs. natural gas-fired CCs, coal plants, and storage facilities based on areas' generation mix (a higher percentage is allocated to renewables in areas with significant renewable penetration).

Figure 20 shows the aggregate amounts of frequency response requirements assumed in our simulations. The 2020 scenarios include the requirements only in CAISO and PAC, whereas the 2030 scenarios model the requirements in all of the WECC Balancing Authority areas. In the Current Practice scenarios each Balancing Authority is obligated to meet its own requirements. With regionalization, reserve sharing is allowed between CAISO and PAC under the CAISO+PAC scenario and within the larger regional footprint (U.S. WECC without PMAs) under the expanded Regional ISO scenarios.

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24 NERC, "2015 Frequency Response Annual Analysis," September 16, 2015. http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/2015_FRAA_Report_Final.pdf

25 CAISO, "Frequency Response Draft Final Proposal," February 4, 2016. https://www.caiso.com/Documents/DraftFinalProposal_FrequencyResponse.pdf

26 See CAISO's reply comments pursuant to the ALJ's February 8, 2016 ruling seeking comment on assumptions and scenarios for use in the CAISO's 2016–17 Transmission Planning Process and future commission proceedings (dated February 29, 2016). https://www.caiso.com/Documents/Feb29_2016_ReplyComments_Assumptions_Scenarios_2016-2017TransmissionPlanning_R13-12-010.pdf

Figure 20: Summary of Frequency Response Requirements

	Total Requirement (MW)	Share Assumed to be Met by Renewables (MW)	Share Assumed to be Met by Gas CC, Coal & Batteries (MW)
CAISO	752	376	376
PAC	209	31	178
CAISO + PAC	**961**	**407**	**554**
Rest of U.S. WECC (non-PMA)	860	264	596
U.S. WECC without PMAs	**1,821**	**671**	**1,150**
PMAs	246	177	69
WECC (non-U.S.)	438	159	278
WECC Total	**2,505**	**1,007**	**1,498**

d. Supply Eligibility and Constraints

In PSO, we defined the reserves that can be provided for each reserve type at the unit level. If committed, thermal units can provide reserves up to an amount that depends on how much they can ramp in 5 minutes for regulation, 10 minutes for spinning, and 15 minutes for load-following reserves. Online natural gas-fired CC plants and coal units are assumed to provide up to 8% of their capacity for frequency response. Energy storage facilities can be used to support all reserve types modeled up to about 200% of their capacity accounting for the amount between full charging and discharging modes. The utility-scale wind and solar units can be used to meet reserve requirements, including regulation, spinning, and load-following (their contribution to frequency response is considered a reduction in requirements; not explicitly modeled). The amount of reserves they can provide is limited by their hourly output before any curtailments and they are subject to the costs associated with curtailments.[27]

The total upward reserve provided by a unit is limited by the head room available between its dispatch point ("Pgen") and maximum capacity ("Pmax"). Similarly, the total downward reserve

27 We applied 100% of curtailment costs for renewables providing upward reserves as the resources must be curtailed first to create the head room needed to provide upward reserves; we applied 25% of curtailment costs for renewables providing downward reserves assuming that they would get curtailed 1/4 of the time when they are used for downward reserves.

provided by a unit is limited by the headroom between its dispatch point ("Pgen") and minimum generation level ("Pmin").

Figure 21 summarizes how we applied constraints to determine the amount of reserves provided by each unit in a given hour.

Figure 21: Generator Reserve Capacity by Reserve Type

		Thermal [1]	Storage [2]	Hydro [3]	Wind and Solar [4]
Upward Reserves					
Reg Up	≤	5 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
Spin	≤	10 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
LF Up	≤	15 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
Frequency Response	≤	8% × Pmax	200% × Pmax	Not explicitly modeled	Not explicitly modeled
TOTAL	**≤**	**Pmax – Pgen**	**Pmax – Pgen**	**Pmax – Pgen**	**Pgen* – Pgen**
Downward Reserves					
Reg Dn	≤	5 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen
LF Dn	≤	15 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen
TOTAL	**≤**	**Pgen – Pmin**	**Pgen – Pmin**	**Pgen – Pmin**	**100% × Pgen**

Notes:

[1] Across thermal units, only gas-fired combined cycle and coal units are assumed to provide frequency response.

[2] Pgen values for storage units are negative during charging. The 200% × Pmax limit accounts for the amount that can be provided between full charging and discharging modes.

[3] The amount of reserves that can be provided by hydro units varies based on unit-specific inputs. On average, hydro units provide about 6% of their capacity for regulation, 7% for spin, and 17% for load-following reserves. They are also used for frequency response (included as a reduction of net requirements; not explicitly modeled).

[4] Pgen* values for renewable units represent hourly output before any curtailments.

8. Transmission Topology and Constraints

The PSO transmission database is highly detailed and based on a WECC power flow case that includes 19,500 buses and 24,000 individual transmission lines connecting those buses. Our representation of the network is consistent with the CAISO Gridview transmission planning model, with the exception of a small group of transmission projects that we removed in the 2020 and 2030 Current Practice and Regional 2 scenarios. Figure 22 summarizes the modifications we made to major future transmission projects in the model. We removed the projects from 2020 to be consistent with their in-service dates. Furthermore, we removed the Gateway South Segment F and the Gateway West Segment D projects from all cases except the 2030 Regional 3 scenario.

We assume the construction of these projects will be driven, at least in part, by state-mandated renewable build outs; the projects are assumed to be completed only if a sufficiently large share of the new renewable builds will take place in Wyoming for the purpose of satisfying state RPS mandates. This new transmission is assumed to enable injection and balancing of the wind generation in the larger regional footprint.

Figure 22: Major Transmission Project Modifications

Transmission Project	WECC Online Year	2020 All Cases	2030 Current Practice, Regional 2	2030 Regional 3
Boardman-Hemingway 500 kV	2021		✓	✓
Gateway South Project: Segment F	2023			✓
Gateway West Project: Segment D	2023			✓
Gateway West Project: Segment E	2023		✓	✓
Centennial II: Harry Allen-El Dorado	2026		✓	✓

We constrain flows on the transmission system based on a number of path, contingency, and nomogram constraints. First among these are the WECC-defined path limits. A WECC path is a group of transmission lines that captures the bulk of power transfer from one area to another. For a given path, the sum of flows on individual lines is restricted to a level *below* the sum of thermal limits on those lines. The use of such paths is a common operating practice and ensures that the power transfer between areas does not result in overloads or compromise reliability. We summarize the simulated WECC path limits in Figure 23.

In the simulations, we enforce transmission-related contingency constraints within the ISO. Similar to path limits, contingency constraints restrict flows on a monitored line or path to avoid thermal overloads due to changes in system conditions caused by a contingency. Each contingency constraint is evaluated with respect to a specific contingency or set of contingencies, such as the outage of a specific nearby line that could redirect more power through the monitored line or path. We enforce a number of other transmission constraints in the model, including additional non-WECC-rated transmission paths (summarized in Figure 24), and phase angle regulator constraints (controllable equipment used by system operators to redirect some flows).

Finally, we enforce a set of nomogram constraints. Nomogram constraints represent linear constraints on combinations of transmission path flows, generation, and load. The major nomograms we simulate are summarized in Figure 25.

Figure 23: WECC Path Limits (MW)

WECC Path Name		2020 All Cases		2030 Current Practice, Regional 2		2030 Regional 3	
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
1	Alberta-British Columbia	1,000	(1,200)	1,000	(1,200)	1,000	(1,200)
2	Alberta-Saskatchewan	150	(150)	150	(150)	150	(150)
3	Northwest-British Columbia	3,000	(3,150)	3,000	(3,150)	3,000	(3,150)
4	West of Cascades-North	10,800	(10,800)	10,800	(10,800)	10,800	(10,800)
5	West of Cascades-South	7,575	(7,575)	7,575	(7,575)	7,575	(7,575)
6	West of Hatwai	4,800	(4,800)	4,800	(4,800)	4,800	(4,800)
8	Montana to Northwest	3,000	(2,150)	3,000	(2,150)	3,000	(2,150)
9	West of Broadview	2,573	(2,573)	2,573	(2,573)	2,573	(2,573)
10	West of Colstrip	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
11	West of Crossover	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
14	Idaho to Northwest	2,400	(1,200)	**3,400**	**(2,250)**	3,400	(2,250)
15	Midway-Los Banos	5,400	(3,265)	5,400	(3,265)	5,400	(3,265)
16	Idaho-Sierra	500	(360)	500	(360)	500	(360)
17	Borah West	2,557	(1,600)	**4,450**	**(4,450)**	4,450	(4,450)
18	Montana-Idaho	337	(256)	337	(256)	337	(256)
19	Bridger West	2,400	(1,250)	2,400	(1,250)	**4,100**	**(2,300)**
20	Path C	2,250	(2,250)	2,250	(2,250)	2,250	(2,250)
22	Southwest of Four Corners	2,325	(2,325)	2,325	(2,325)	2,325	(2,325)
23	Four Corners 345/500 Qualified Path	1,000	(1,000)	1,000	(1,000)	1,000	(1,000)
24	PG&E-Sierra	160	(150)	160	(150)	160	(150)
25	PacifiCorp/PG&E 115 kV Interconnection	100	(45)	100	(45)	100	(45)
26	Northern-Southern California	4,000	(3,000)	4,000	(3,000)	4,000	(3,000)
27	Intermountain Power Project DC Line	2,400	(1,400)	2,400	(1,400)	2,400	(1,400)
28	Intermountain-Mona 345 kV	1,400	(1,200)	1,400	(1,200)	1,400	(1,200)
29	Intermountain-Gonder 230 kV	200	(200)	200	(200)	200	(200)
30	TOT 1A	650	(650)	650	(650)	650	(650)
31	TOT 2A	690	(690)	690	(690)	690	(690)
32	Pavant-Gonder InterMtn-Gonder 230 kV	440	(235)	440	(235)	440	(235)
33	Bonanza West	785	(785)	785	(785)	785	(785)
35	TOT 2C	600	(580)	600	(580)	600	(580)
36	TOT 3	1,680	(1,680)	1,680	(1,680)	1,680	(1,680)
37	TOT 4A	1,025	(99,999)	1,025	(99,999)	**1,775**	**(1,775)**
38	TOT 4B	880	(880)	880	(880)	880	(880)
39	TOT 5	1,680	(1,680)	1,680	(1,680)	1,680	(1,680)
40	TOT 7	890	(890)	890	(890)	890	(890)
41	Sylmar to SCE	1,600	(1,600)	1,600	(1,600)	1,600	(1,600)
42	IID-SCE	1,500	(1,500)	1,500	(1,500)	1,500	(1,500)
43	North of San Onofre	2,440	(2,440)	2,440	(2,440)	2,440	(2,440)
44	South of San Onofre	2,500	(2,500)	2,500	(2,500)	2,500	(2,500)
45	SDG&E-CFE	408	(800)	408	(800)	408	(800)
46	West of Colorado River (WOR)	11,800	(11,200)	11,800	(11,200)	11,800	(11,200)
47	Southern New Mexico (NM1)	1,048	(1,048)	1,048	(1,048)	1,048	(1,048)
48	Northern New Mexico (NM2)	1,970	(1,970)	1,970	(1,970)	1,970	(1,970)
49	East of Colorado River (EOR)	9,900	(10,200)	9,900	(10,200)	9,900	(10,200)
50	Cholla-Pinnacle Peak	1,200	(1,200)	1,200	(1,200)	1,200	(1,200)
51	Southern Navajo	2,800	(2,800)	2,800	(2,800)	2,800	(2,800)
52	Silver Peak-Control 55 kV	17	(17)	17	(17)	17	(17)
54	Coronado-Silver King 500 kV	1,494	(1,494)	1,494	(1,494)	1,494	(1,494)
55	Brownlee East	1,915	(1,915)	1,915	(1,915)	1,915	(1,915)
58	Eldorado-Mead 230 kV Lines	1,140	(1,140)	1,140	(1,140)	1,140	(1,140)
59	WALC Blythe - SCE Blythe 161 kV Sub	218	(218)	218	(218)	218	(218)
60	Inyo-Control 115 kV Tie	56	(56)	56	(56)	56	(56)
61	Lugo-Victorville 500 kV Line	900	(2,400)	900	(2,400)	900	(2,400)
62	Eldorado-McCullough 500 kV Line	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
65	Pacific DC Intertie (PDCI)	3,220	(3,100)	3,220	(3,100)	3,220	(3,100)
66	COI	4,800	(3,675)	4,800	(3,675)	4,800	(3,675)
71	South of Allston	4,100	(4,100)	4,100	(4,100)	4,100	(4,100)
73	North of John Day	8,400	(8,400)	8,400	(8,400)	8,400	(8,400)
75	Hemingway-Summer Lake	2,400	(1,200)	2,400	(1,200)	2,400	(1,200)
76	Alturas Project	300	(300)	300	(300)	300	(300)
77	Crystal-Allen	950	(950)	950	(950)	950	(950)
78	TOT 2B1	600	(600)	600	(600)	600	(600)
79	TOT 2B2	265	(300)	265	(300)	265	(300)
80	Montana Southeast	600	(600)	600	(600)	600	(600)
81	Southern Nevada Transmission Interface (SNIT)	4,533	(3,790)	4,533	(3,790)	4,533	(3,790)
82	TotBeast	2,465	(2,465)	2,465	(2,465)	2,465	(2,465)
83	Montana Alberta Tie Line	325	(300)	325	(300)	325	(300)

Figure 24: Other Modeled Path Limits (MW)

	2020 Current Practice		2020 CAISO + PAC		2030 Current Practice		2020/2030 Regional ISO	
Path Name	**Maximum**	**Minimum**	**Maximum**	**Minimum**	**Maximum**	**Minimum**	**Maximum**	**Minimum**
Aeolus South	-	-	-	-	-	-	**1,700**	**(1,700)**
Aeolus West	-	-	-	-	-	-	**2,670**	**(2,670)**
AZ Palo Verde East	8,010	(8,010)	8,010	(8,010)	8,010	(8,010)	8,010	(8,010)
CA IPP DC South	50,000	(50,000)	50,000	(50,000)	50,000	(50,000)	50,000	(50,000)
CA PDCI South	2,780	(3,100)	2,780	(3,100)	2,780	(3,100)	2,780	(3,100)
CA SCIT	17,700	(17,700)	17,700	(17,700)	17,700	(17,700)	17,700	(17,700)
CA Southern CA Imports	999,999	(14,750)	999,999	(14,750)	999,999	(14,750)	999,999	(14,750)
ID Midpoint West	4,400	(4,400)	4,400	(4,400)	4,400	(4,400)	4,400	(4,400)
NV NV Energy Southern Cut Plane	3,500	(3,050)	3,500	(3,050)	3,500	(3,050)	3,500	(3,050)
OR/WA West of John Day	3,450	(3,450)	3,450	(3,450)	3,450	(3,450)	3,450	(3,450)
OR/WA West of McNary	4,500	(4,500)	4,500	(4,500)	4,500	(4,500)	4,500	(4,500)
OR/WA West of Slatt	5,500	(5,500)	5,500	(5,500)	5,500	(5,500)	5,500	(5,500)
WA North of Hanford	4,100	(2,948)	4,100	(2,948)	4,100	(2,948)	4,100	(2,948)
CAISO Zero Net Export	0	(99,999)	**776**	(99,999)	**2,000**	(99,999)	**8,000**	(99,999)

Figure 25: Nomogram Constraint Limits (MW)

	2020/2030 All Cases	
Nomogram Name	**Maximum**	**Minimum**
AeolW-Aeolus S	6,458	(99,999)
AeolW-Bonanza W	6,595	(99,999)
AeolW-TOT1A	17,458	(99,999)
BrdgW-Aeolus S	12,796	(99,999)
BrdgW-Bonanza W	10,406	(99,999)
BrdgW-Path C	16,856	(99,999)
IPP DC	361	(99,999)
Path 18 Exp	337	(99,999)
Path 18 Imp	256	(99,999)
Path 22	3,113	(99,999)
Path 8	7,925	(99,999)
COB	5,100	(99,999)
COI 1	6,763	(99,999)
COI 2	4,560	(99,999)
Jday COI 1	4,648	(99,999)
Jday COI 3	9,793	(99,999)
Jday COI PDCI 1	7,650	(99,999)
Jday COI PDCI 2	7,900	(99,999)
Jday COI PDCI 3	17,115	(99,999)
Jday PDCI 1	3,002	(99,999)
Jday PDCI 3	5,547	(99,999)
* LDWP 25% LocalMinGen	99,999	(99,999)
CA Path15 N2S-MidwayGen	3,265	(99,999)
CA Path26 N2S with RAS	3,450	(99,999)
CA South of SONGS SN Level 2	2,200	(99,999)

Notes:

* LDWP 25% LocalMinGen has a time-varying min. limit equal to 25% of LDWP gross load.

C. SIMULATION RESULTS AND REGIONAL-MARKET IMPACT METRICS

This section summarizes the key results from production cost simulations (generation outputs, net imports, market prices, *etc.*), and the metrics that are relevant to the SB 350 study, including the impacts of a regional market on: WECC-wide production costs, WECC-wide and California GHG emissions, and California's net production, purchases, and sales costs estimated for the overall ratepayer impact analysis.

We first show the model results and metrics for the baseline scenarios (2020: Current Practice, CAISO+PAC; and 2030: Current Practice 1, Regional 2, and Regional 3). After that, we discuss various sensitivity scenarios that are simulated in PSO to understand the effects of changes to some of the key inputs and modeling assumptions.

1. Baseline Scenarios

a. Generation Output

In an ISO-operated regional market, de-pancaked transmission and scheduling charges, lower market friction and hurdles, regionally-optimized unit commitment and economic dispatch, reduced operating reserve requirements, and reserve sharing arrangements allow for increased access to lower-cost generation resources and impact the overall generation patterns within the regional footprint.

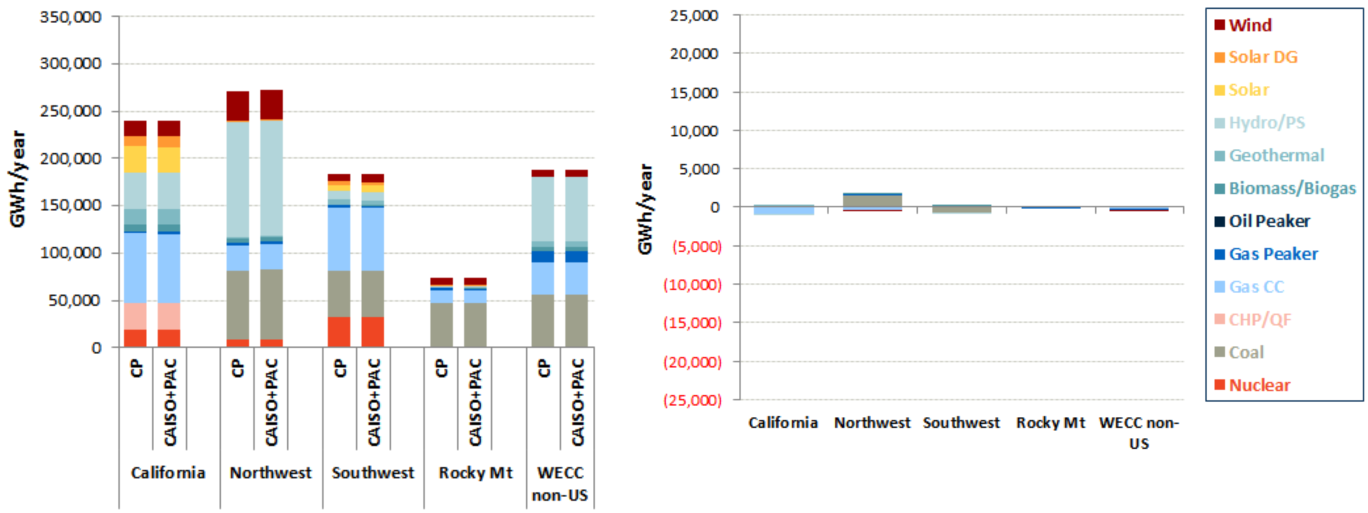
As shown in Figure 26, the limited scope of regionalization in 2020 with only CAISO+PAC has a very small effect on generation results. In California, natural gas-fired generation decreases by approximately 600 GWh annually, which corresponds to 0.6% of the total simulated generation from natural gas-fired plants in the state. In the rest of WECC, annual natural gas-fired generation declines slightly by around 350 GWh (0.2% of total). The reduced output from natural gas-fired plants is replaced with a small amount of net increase in WECC-wide coal-fired generation of about 880 GWh (0.4% of total), which is largely driven by higher production from coal units in the PacifiCorp area.

It is important to note that the impact on 2020 coal dispatch is overstated due to the generic natural gas-based CO_2 hurdle rate applied to all market imports into California. Contrary to the hurdles that would actually be imposed, this simplification artificially advantages coal units in the market simulations. See Volume I for a more detailed discussion of this point.

Figure 26: Generation Impacts of the Regional Market Under the 2020 CAISO+PAC Scenario

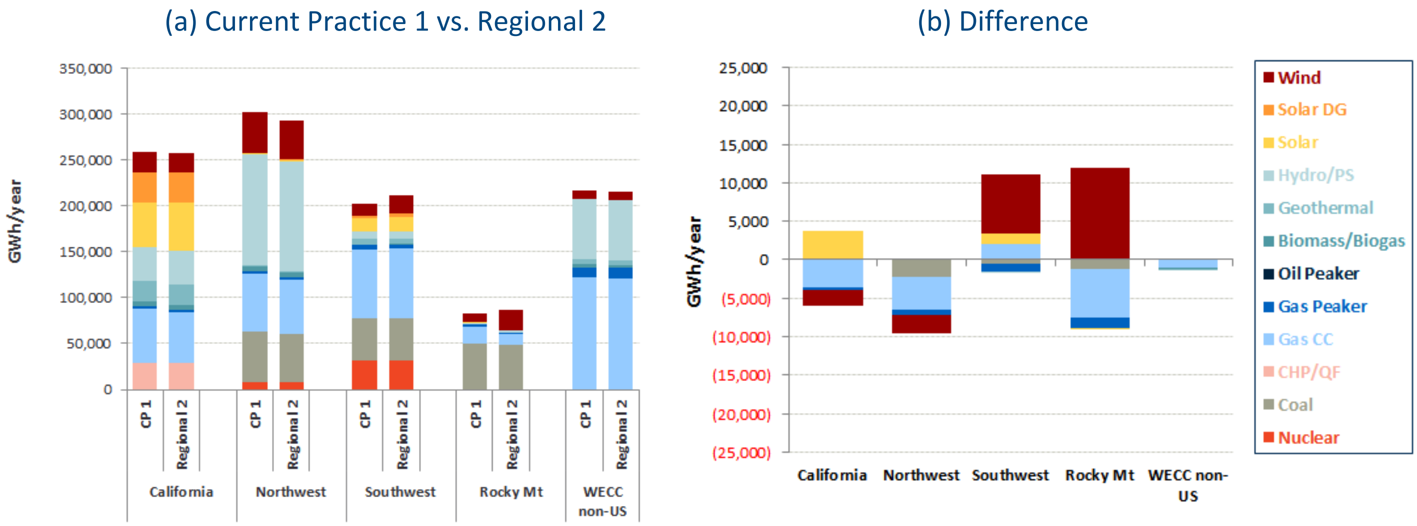
(a) 2020 Current Practice vs. CAISO+PAC

(b) Difference



With the larger regional footprint covering all of the U.S. WECC without the PMAs the 2030 simulations show more significant shifts in generation patterns. Figure 27 shows the impact of the expanded regional market on generation results under the Regional 2 scenario. Due to a re-optimized renewable portfolio to meet California's 50% RPS and the additional renewables facilitated by the regional market (beyond RPS), the amount of renewable generation in California and rest of WECC changes. In California, the renewable portfolio for the Regional 2 scenario has slightly higher in-state renewable generation than the Current Practice 1 scenario (more solar, partially offset by less wind). In the rest of WECC, renewable generation increases significantly by about 18,800 GWh, most of which is from the additional wind resources in Wyoming and New Mexico assumed to be facilitated by the regional market beyond RPS mandates (see Volume XI). The higher overall renewable generation displaces the fossil-fuel generation in the system including 3,900 GWh of gas generation in California (4.3%), 12,500 GWh of gas generation in the rest of WECC (4.1%), and 4,000 GWh of coal generation in the rest of WECC (2.7%).

Figure 27: Generation Impacts of the Regional Market
Under the 2030 Regional ISO Scenario 2



Under the Regional 3 scenario, California procures more out-of-state renewable resources to meet its 50% RPS (as discussed by E3 in Volume IV). As shown in Figure 28, the total renewable generation in California decreases by approximately 10,000 GWh (mostly solar) compared to Current Practice 1. At the same time, the amount of renewables in the rest of WECC increases by 30,000 GWh. Of this, about one-third is associated with the incremental out-of-state resources procured by California and the remaining two-thirds is from the additional wind (beyond RPS) enabled by the regional market. Higher renewables in the system (on a net basis) results in lower fossil-fuel generation by 6,900 GWh of gas generation in California (7.7%), 11,800 MWh of gas generation in the rest of WECC (3.9%), and 1,100 GWh of coal generation in the rest of WECC (0.8%).

Figure 28: Generation Impacts of the Regional Market Under the 2030 Regional ISO Scenario 3

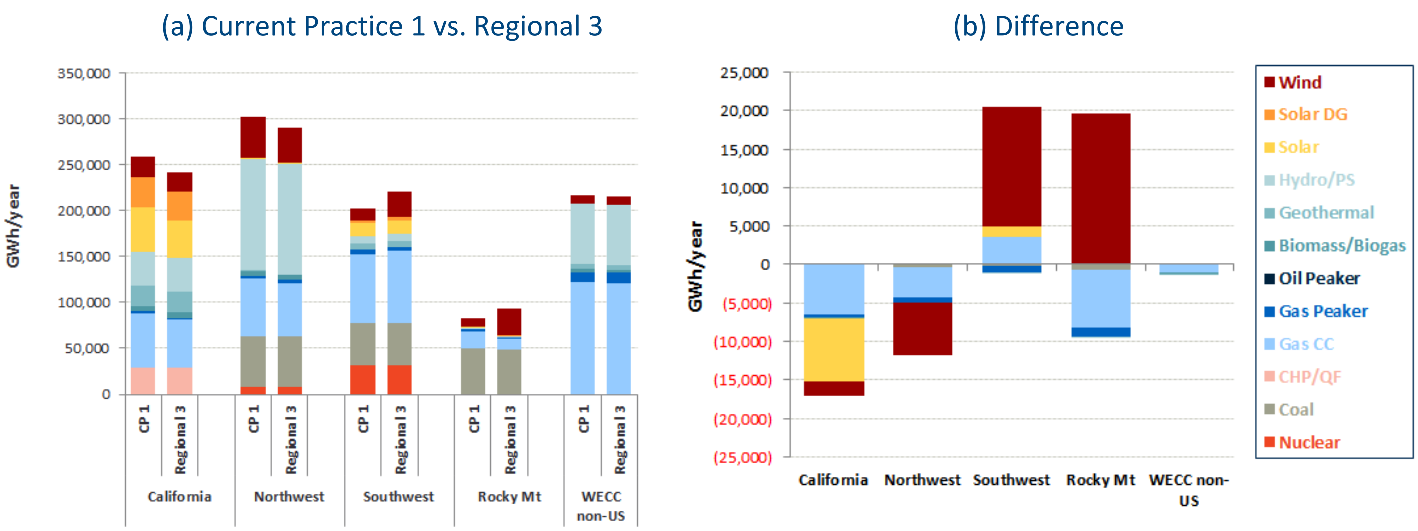


Figure 29 compares simulated natural gas-fired generation in California against historical data. Increased amounts of renewables added to meet state's RPS result in the decline of gas generation by about 12% in 2020 and 25–30% in 2030 compared to the recent historical levels (except 2011, which was a wet hydro year both in California and WECC-wide).

Figure 29: Simulated vs. Historical Natural Gas-Fired Generation in California

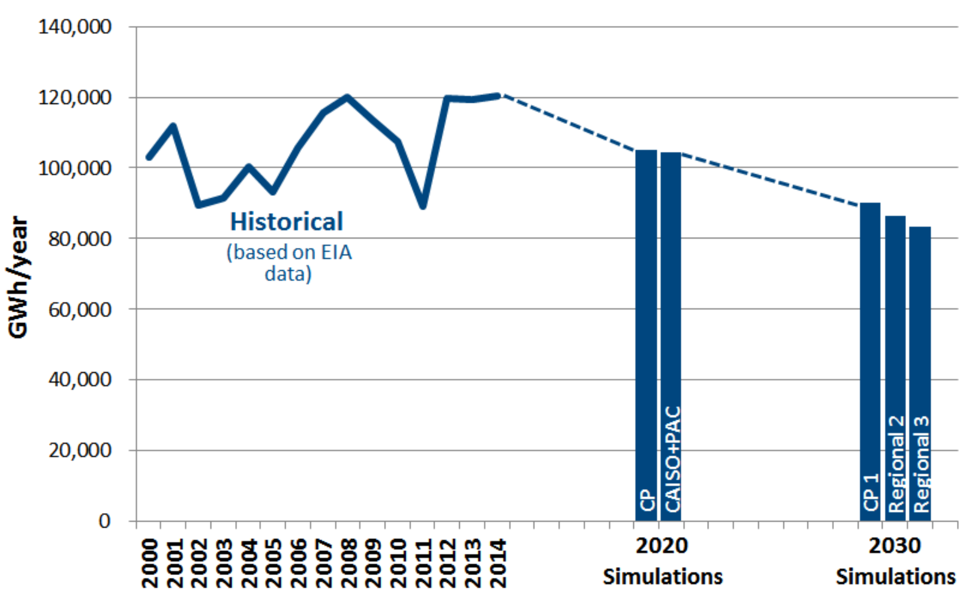
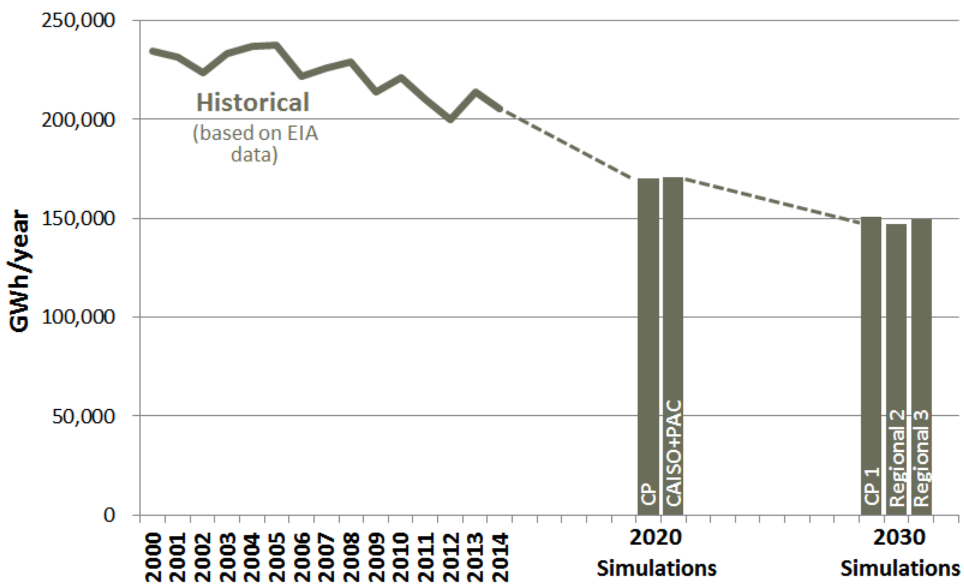


Figure 30 compares simulated coal-fired generation in the U.S. WECC against historical data. With retiring coal plants and the addition of renewables, the coal dispatch in 2020 is projected to decrease substantially by about 17% from recent historical levels; by 2030, it is projected to have decreased by more than 25%. The additional impact of a regional market on coal-fired generation is much smaller than year-by-year variations of historical levels. Overall, the simulated amount of coal-fired generation is driven primarily by coal plant retirements and adjustments in response to environmental regulations, not by the regional market impacts.[28]

Figure 30: Simulated vs. Historical Coal-Fired Generation in the U.S. WECC



b. CAISO's Net Imports

Historically, the CAISO has been a net importer of energy during all hours of the year. As shown in Figure 31, this essentially continues to be the case in the 2020 scenarios with the CAISO's net physical imports averaging at around 4,000 MW. In the CAISO+PAC scenario the regional market has only a very small effect on CAISO's imports, which is consistent with the generation results discussed in the earlier section.

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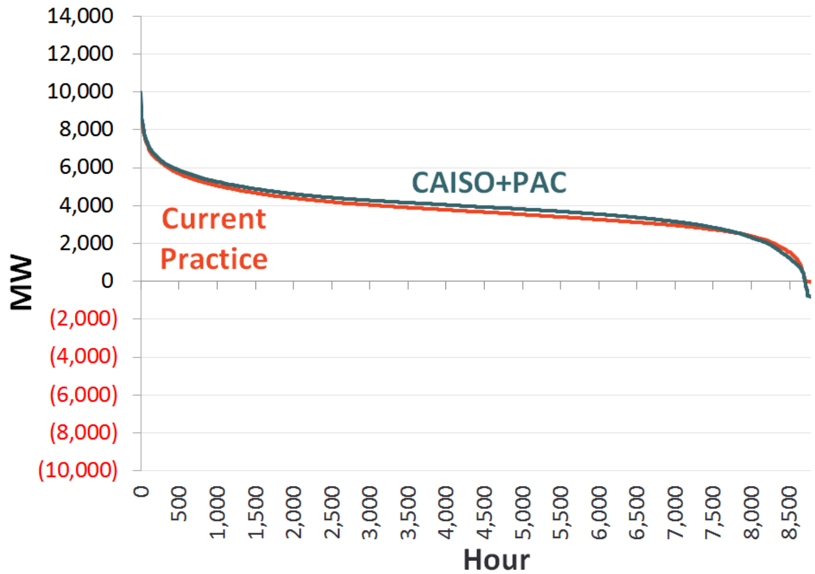
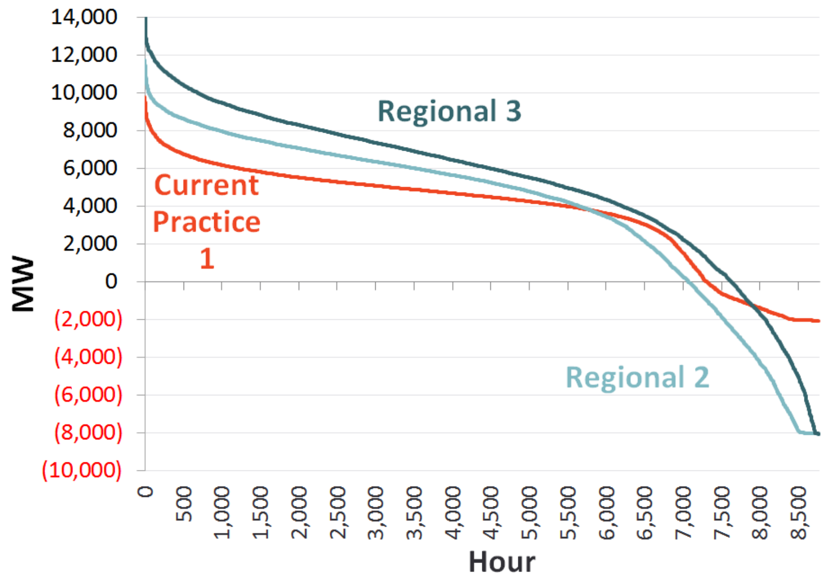
28 For example, as shown in Section 2.e below and discussed in Volume I of this report, the impact of even a modest $15/tonne CO_2 price in the rest of WECC would reduce coal dispatch by around 20%, while the differences across Current Practice, CAISO+PAC, and expanded Regional ISO scenarios are limited to only ±3%.

Figure 31: 2020 CAISO Net Physical Import Duration Curves



In 2030, the CAISO is still projected to import a significant amount of energy during most of the hours of the year. However, the significant amount of renewables added to meet 50% RPS allows CAISO to start exporting power during periods with high renewable output. Figure 32 compares the CAISO's net physical import duration curves for the three 2030 baseline scenarios analyzed. Under the 2030 Current Practice 1 scenario, CAISO exports very little due to the 2,000 MW bilateral export limit. In the 2030 regional market cases, the CAISO imports more energy (except during oversupply conditions) as a result of reduced hurdle rates on market-based imports. At the same time, the increased CAISO export limit under the regional market scenarios allows CAISO to manage oversupply conditions more effectively and export excess intermittent renewable generation without curtailments. Compared to Regional 2, CAISO-wide imports are higher and exports are lower in Regional 3, which is driven by the shift in buildout of in-state and out-of-state renewable resources between the two regional market scenarios.

Figure 32: 2030 CAISO Net Physical Import Duration Curves



c. *Renewable Curtailments*

The curtailments of renewable resources in the model are driven by oversupply conditions. Figure 33 illustrates how curtailments are determined in the model for the Current Practice 1 scenario. During hours with high levels of renewable output, oversupply is managed by ramping down all flexible resources, charging storage facilities, and selling off surplus generation in bilateral markets up to the bilateral export limit defined in the model. If the export limit is binding, the excess generation amount needs to be curtailed. As shown in Figure 33, on that particular day California imports 3,000 to 5,000 MW during the evening and morning hours (the grey area on top of the supply stack), but becomes a substantial net exporter of approximately 6,000 MW from approximately 8 am to 5 pm (the difference between the top of the grey area and the dashed black line). Even under the simulated 2,000 MW limit to the bilateral re-export of new renewable resources, the Scenario 1 simulation assumes that the state will be able to bilaterally market and export substantial amounts of excess supply, causing an approximately 10,000 MW daily swing between net imports and net exports. As of the date of this report, the state has not experienced any net exports. Based on CAISO information, the lowest level of net imports experienced by the CAISO to date has been approximately 2,000 MW.

Figure 33: Illustration of Simulated Daily Dispatch and Renewable Curtailments (Current Practice 1 Scenario; May 29, 2030)

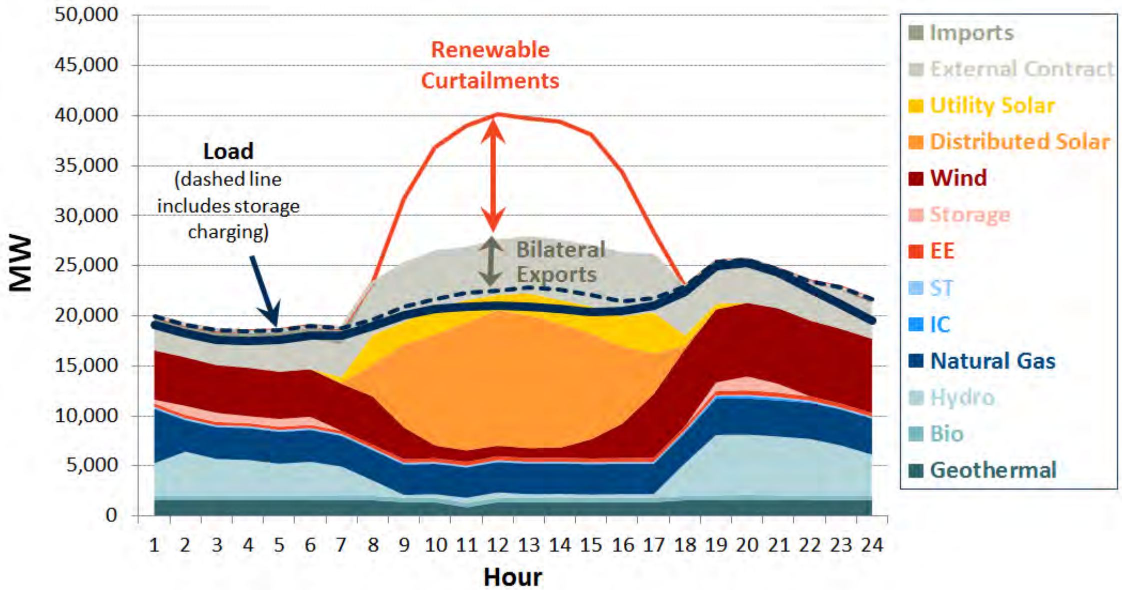


Figure 34 below shows the simulated amounts of renewable energy curtailments in California across the three baseline scenarios and compares the results between the PSO and RESOLVE models. More limited bilateral export ability in the Current Practice 1 scenario (assuming all 3,000–4,000 MW of existing imports plus an additional 2,000 MW can be sold and re-exported bilaterally) results in significant curtailments of in-state renewable generation even under the assumed optimal portfolio.

Figure 34: Estimated California Renewable Energy Curtailments

	2030 Current Practice 1 (million MWh/yr)	2030 Regional ISO 2 (million MWh/yr)	2030 Regional ISO 3 (million MWh/yr)
PSO	4.5	0.5	0.1
RESOLVE	4.8	1.6	1.2
Delta	**(0.3)**	**(1.1)**	**(1.1)**

Curtailment patterns are generally similar between the PSO and RESOLVE even though there are some important differences between the two models. The deviations are to be expected since PSO and RESOLVE are different modeling platforms utilized for different purposes in the SB 350 study. Even though key input assumptions are consistent between the two models, the results will vary due to differences in the granularity of the models and how the simulations are conducted.

PSO is a nodal production cost model used to simulate hourly day-ahead unit commitment and economic dispatch and it includes a very detailed representation of the entire WECC transmission system. RESOLVE is less granular on operational constraints, but it considers future investment needs and simultaneously solves for least-cost portfolios of renewable resources and integration solutions.

In PSO, all 8,760 hours of the year are simulated for weather-normalized monthly peak load and energy assumptions. In contrast, the RESOLVE model simulates only a limited number of "representative" hours, but draws these representative hours from a full distribution of weather and load conditions. Load is a big driver of the curtailments as it impacts the extent of oversupply in the system. All else being equal, below-average load would trigger more curtailments and above-average load would allow for less curtailments. Due to the asymmetric nature of this impact (curtailments cannot drop below zero), modeling the distribution of weather and load conditions would typically result in higher levels of curtailments compared to modeling only average/normal conditions. This is the likely reason why curtailments are estimated to be higher in RESOLVE than in PSO. The difference between the two models is less pronounced in the Current Practice 1 scenario because the limited flexibility of bilateral markets to manage oversupply conditions leads to significant curtailments irrespective of whether the load levels are below-average, average, or above-average.

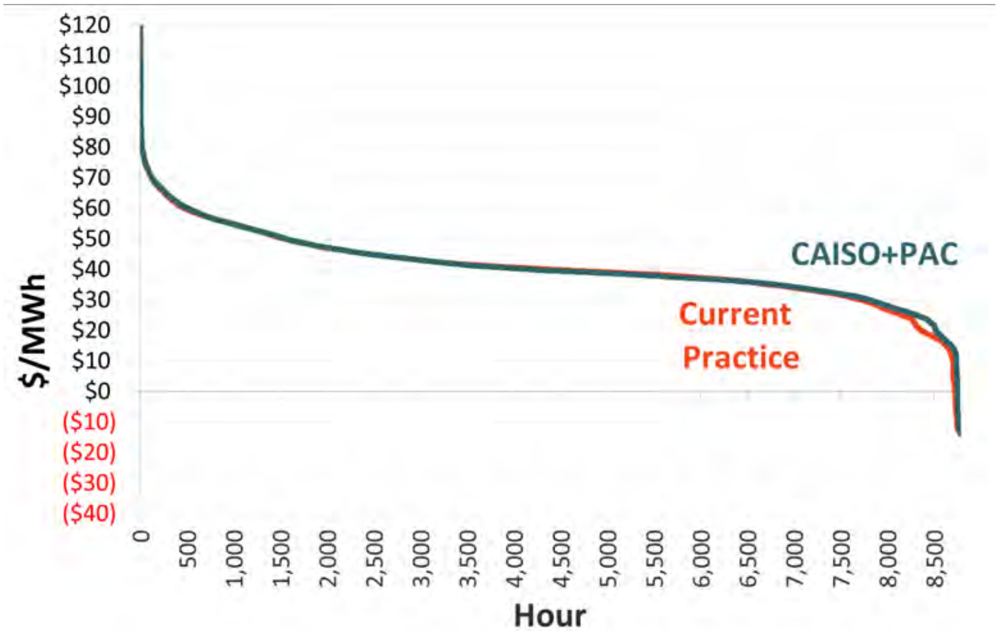
It is important to note that both PSO and RESOLVE will likely understate the full magnitudes of renewable curtailments since they simulate market outcomes deterministically (equivalent to a day-ahead market) without taking into account the real-time uncertainties and day-ahead forecasting errors for load and renewable generation output. Experience in other markets with high levels of renewable penetration suggests that most of the renewable curtailments occur in real-time markets (as opposed to on a day-ahead basis) and are driven by forecasting errors and unexpected changes in market conditions.

d. Wholesale Electricity Prices

With expansion of an ISO-operated regional market, the changes in generation dispatch and curtailment patterns impact the prices of electricity in California and across the WECC. These prices are used to determine customer costs of market purchases and revenues from exports as a part of the calculation of California net production, purchases, and sales cost (discussed in Section f below) for the California ratepayer impact analysis.

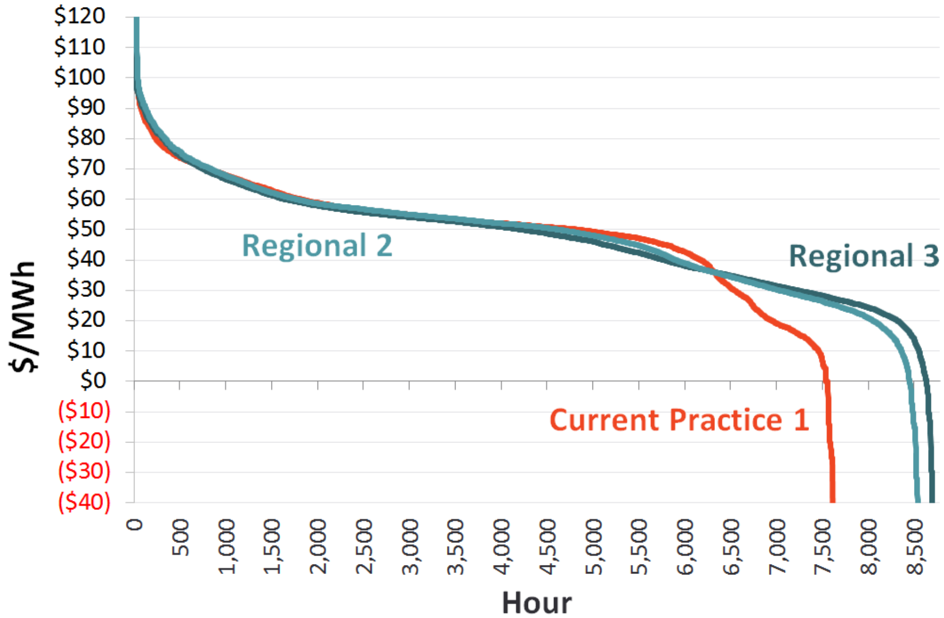
Figure 35 displays the 2020 hourly load-weighted LMPs in CAISO sorted from highest to lowest. There is very little movement in prices between the Current Practice and CAISO+PAC scenarios, which is consistent with the small changes observed in generation dispatch due to the limited scope of regionalization.

Figure 35: 2020 CAISO Price Duration Curves



Compared to 2020, Figure 36 shows a more significant price impact in the 2030 simulations with the larger regional footprint, especially during off-peak hours when prices are low or even negative. Negative prices occur when oversupply conditions necessitate curtailment of renewable energy resources, which happens more often under Current Practice 1 due to the more stringent CAISO export limit applied to capture the limited flexibility of bilateral markets during oversupply conditions. The reduction in curtailments under the expanded Regional ISO scenarios limits the number of negatively-priced hours considerably, thereby mitigating the costs paid by the California ratepayers. In the PSO model, the curtailment prices are set to negative $300/MWh for existing resources and resources that are expected to be online by 2020, and negative $100/MWh for the incremental renewables added between 2020 and 2030. However, our baseline estimates of California production, purchase, and sales costs conservatively assume that settlement prices do not drop below zero during oversupply conditions (give power away for free, but not pay more) as discussed further in Section f.

Figure 36: 2030 CAISO Price Duration Curves



e. WECC-Wide Production Cost Savings

Production cost savings are accrued across the entire WECC region due to the efficiency of a larger regional ISO footprint and the facilitation of zero-variable-cost renewable resources. The savings reflect the estimated cost reductions in fuel, startup, and variable O&M (excluding AB 32 carbon costs) calculated at the unit-level and then aggregated for the WECC region.[29] They are driven by:

- **Optimized joint unit commitment and dispatch** across a larger, consolidated balancing area with de-pancaked transmission charges;
- **Reducing/removing hurdles** faced by bilateral trades that allow for the commitment and dispatch of lower-cost renewable resources across a larger footprint;
- **Sharing (and joint dispatch of) resources** used as operating reserves;
- **Higher ability to (re)export excess renewable generation** from California to the rest of WECC; and
- **Integration of additional renewable resources** beyond state RPS mandates.

[29] Assumptions on unit-specific start-up cost and variable O&M are based on CAISO's model. Startup costs are modeled as a single aggregated cost for each unit, which represents both a fixed component and a fuel cost component.

Figure 37 shows how our production cost results change across the baseline scenarios simulated and the impact of regionalization in 2020 and 2030. The regional production savings are estimated to be $18 million in 2020 (in 2016 $), which corresponds to a 0.1% reduction of the total production costs. The relatively low magnitude of savings is due to the limited scope of the regional market under the CAISO+PAC scenario. The majority of the $18 million of savings comes from a reduction in startup costs, indicating that units are starting and stopping less as they are utilized to serve a slightly larger and more diverse footprint with the expansion of the regional market. With the larger regional market in 2030, the WECC-wide production cost savings are estimated to be $883 million (4.5%) under Regional 2 and $980 million (5.0%) under Regional 3. The larger benefits are driven by the region's increased access to lower-cost generation under a jointly-optimized system with reduced hurdles; California's increased ability to manage oversupply conditions and re-export/sell excess renewable generation, which would have been curtailed otherwise; and the addition of the "beyond-RPS" wind resources (without variable production costs) facilitated by the regional market. Without these "beyond RPS" renewable resources, 2030 production cost savings are approximately $335 million/year as discussed in Section 2.d below.

Figure 37: Summary of Annual Production Cost Results (2016 $million)

	2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
Fuel cost	$14,316	$14,312	$17,602	$16,844	$16,809
Start-up cost	$436	$421	$769	$673	$605
Variable O&M cost	$1,380	$1,382	$1,188	$1,159	$1,164
TOTAL	**$16,133**	**$16,115**	**$19,559**	**$18,676**	**$18,579**
Impact of Regionalization		($18) (0.1%)		($883) (4.5%)	($980) (5.0%)

* Based on fuel, startup, and variable O&M costs only

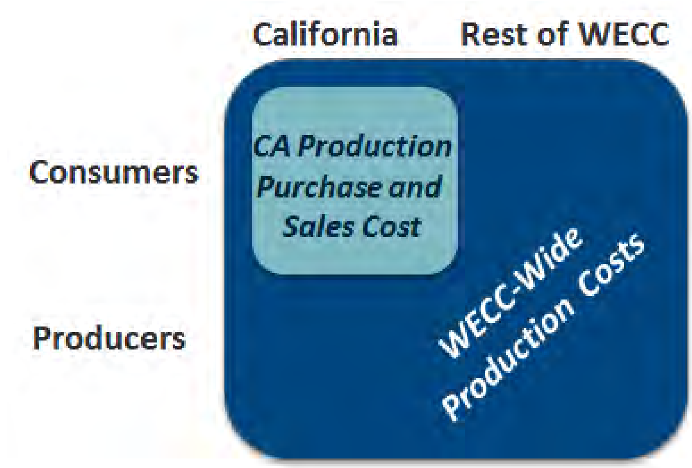
<u>Does not include</u> societal benefits of emission reductions or incremental investment costs associated with additional renewables facilitated by the regional market in 2030 Scenarios 2 and 3.

f. California Net Production, Purchases, and Sales Cost

We calculated the operating cost impacts of the regional markets to California ratepayers consistent with the CAISO's Transmission Economic Assessment Methodology ("TEAM"), which was adopted in 2004 to improve the process for identifying and evaluating "economic" transmission projects that would improve system efficiency and reduce costs.[30]

Figure 38 illustrates the relationship between California's net production, purchases, and sales costs and WECC-wide production cost. For the purpose of the SB 350 study, the operating-cost impacts to California ratepayers are calculated on a state-wide basis and they do not represent impacts on any of the individual parties, utilities, generators, or customer classes. These operating-cost impacts of regional markets are combined with other impacts (such as incremental transmission costs or generation investment cost savings) to determine the overall California ratepayer impacts.

Figure 38: Scope of Operating Cost Impacts



TEAM outlines a metric for analyzing impacts from an ISO participant's perspective. Impacts are defined as the change in consumer surplus, plus the change in competitive rents, plus the change in congestion revenue. For the purposes of this study, this metric comes down to:

(+) <u>Generator costs</u> (fuel, startup, variable O&M, GHG) for generation owned or contracted by the load-serving utilities, which affects consumer surplus;

(+) <u>Costs of market purchases</u> from merchant generators in California and imports from neighboring regions, which affect consumer surplus and are adjusted for congestion revenue;

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30 California ISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

(−) **Revenues from market sales** and exports, which affects consumer surplus and are adjusted for congestion revenue.[31]

For the CAISO load-serving entities, we determined the owned and contracted generators based on CAISO's 2015–16 TPP model.[32] The renewable resources added to meet the state's RPS are included as contracted units as well. In each of the hours, CAISO's net market position is calculated as "short" if it needs additional purchases to meet its load obligations and "long" if it has surplus generation. Hourly short positions are met first by purchases from CAISO-internal merchant generators at the cost of average generator LMP and then by imports from neighboring regions at the average import border LMP. Consistent with TEAM, the use of generator and border LMPs implies that ratepayers are refunded any CAISO-internal congestion charges incurred to deliver energy from the generators or imports to load.[33] The revenue credit associated with any hourly long positions is calculated based on the average export border LMP.

For the rest of California (BANC, IID, LADWP, TIDC), we performed less detailed "adjusted production cost" (APC) calculations. In these calculations, we did not split generation for owned and contracted vs. merchant. Rather, we estimated the cost of market purchases and revenues from market sales based on average generator LMPs since import and export border LMPs were not available for entities other than CAISO.

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[31] Note that competitive rents from strategic bidding and/or uncompetitive market behavior are not included in the production cost model.

[32] The details on unit ownership and contract assumptions are provided as a part of the confidential data released for stakeholders. Please see Section A.3 for additional information on how to access study data.

[33] Congestion Revenue Rights (CRRs) are financial instruments that individual market participants can use to hedge their congestion risk. Market participants are either allocated CRRs or can purchase them in an auction. All CRR auction revenues and congestion revenues in excess of those paid to CRR holders are used to reduce the CAISO's transmission access charges. Under the TEAM framework, which takes a system-wide perspective, congestion revenues are therefore treated as a benefit to ratepayers. For simplicity, the study team assumed that all transactions made on behalf of California ratepayers are fully hedged. In reality, the transactions will not line up exactly with participants' CRR positions, leading to some exposure to congestion costs. However, the study team believes that this assumption is reasonable for analyzing the impacts of a regional market because: (1) California load serving entities are mostly hedged due to their allocations of CRRs, and (2) any unhedged congestion payments are used to reduce the transmission access charges, providing a benefit to California ratepayers. Also, since California ratepayers are assumed to pay for any transmission needed for new renewable resources, they would be allocated additional CRRs under current rules, largely or entirely offsetting any increase in congestion costs between those resources and California loads.

In general, price effects (*i.e.*, a regional market's impact on prices) are different in hours when California is a net buyer of power than in hours when California is a net seller of power. During net short conditions, a reduction in wholesale power prices will tend to reduce customer costs, since the cost of market purchases decreases.[34] In contrast, during net long conditions, a reduction in wholesale power prices will tend to increase customer costs; which means customers benefit if wholesale market prices increase.[35]

For 2020, net cost savings are relatively small due to the very limited Regional ISO assumed. Figure 39 provides a summary of the results under the 2020 scenarios with estimated annual state-wide savings at about $10 million (in 2016 dollars).

34 For example, if a utility's retail load exceeds its owned and contracted generation (*i.e.*, the utility is net short on energy) and the wholesale power price is $40/MWh, this means the utility's PPA provides energy worth $40/MWh with a net cost of $30/MWh for the renewable attributes of the contract. By paying the $70/MWh PPA price, the utility avoids buying wholesale power at $40/MWh for the quantities supplied by the contract, and the utility implicitly pays $30/MWh for renewable attributes. Any load not covered by owned and contracted generation will have to be bought at the wholesale price of $40/MWh. Net customer costs to serve all load will be equal to the PPA price for the contracted amounts plus any wholesale purchases for energy at the wholesale price.

35 If the utility's owned and contracted generation exceeds its retail load (*i.e.*, the utility is net long on energy), it will need to sell the excess energy in the wholesale market. For example, assume that the $70/MWh PPA exceeds the utility's load in a particular hour (*e.g.*, during the late spring when loads are still low but solar generation is high). In that case, the utility will have to sell the excess energy on the market, and the revenues of that sale will be credited against customer costs. So, if the wholesale price is $40/MWh, the net customer costs for the oversupply of energy will be $30/MWh, which is equal to the $70/MWh less the $40/MWh of market sales (revenues). If wholesale power prices fall to zero, the net customer costs associated with that oversupply of energy will be the full $70/MWh since they will get zero revenues from market sales.

Figure 39: 2020 California Annual Net Power Production, Purchases, and Sales Costs

	GWh		$/MWh		$MM/yr	
	2020 Current Practice	2020 CAISO +PAC	2020 Current Practice	2020 CAISO +PAC	2020 Current Practice	2020 CAISO +PAC
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	167,168	166,495	$17.8	$17.7	$2,974	$2,944
Cost of CAISO-Internal Market Purchases	67,774	66,387	$44.7	$44 5	$3,030	$2,957
Cost of CAISO Market Imports	4,902	6,980	$48.2	$47.1	$236	$328
Revenues from Exports of Owned & Contracted Gen	(417)	(436)	$1.8	$7.7	($1)	($3)
Cong. Revenues from Export of Merchant Gen					($0)	$1
TOTAL	**239,427**	**239,427**	**$26.1**	**$26.0**	**$6,238**	**$6,226**
Impact of Regionalization						($12)
						(0 2%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	39,538	39,766	$23.1	$23 2	$912	$923
Cost of Market Purchases	15,965	15,739	$44.9	$45 0	$717	$708
Revenues from Market Sales	(3,442)	(3,444)	$33.5	$33 5	($115)	($115)
TOTAL	**52,062**	**52,062**	**$29.1**	**$29.1**	**$1,514**	**$1,516**
Impact of Regionalization						$2
						0.1%
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	206,706	206,262	$18.8	$18.7	$3,885	$3,867
Cost of Market Purchases	88,641	89,107	$44.9	$44 8	$3,983	$3,994
Revenues from Market Sales	(3,859)	(3,880)	$30.2	$30.4	($116)	($118)
TOTAL	**291,488**	**291,488**	**$26.6**	**$26.6**	**$7,752**	**$7,742**
Impact of Regionalization						**($10)**
						(0.1%)

Our 2030 analysis shows that a regional market will allow California utilities to (1) buy power at a lower price when they are net buyers; and (2) sell power at higher market prices during periods of oversupply, thus significantly reducing customer costs. As shown in Figure 40, estimated annual savings in 2030 increase to $104 million (in Regional 2) and $523 million (in Regional 3) (all 2016 dollars). These changes are explained as follows:

- Regional 2 includes less wind generation and more solar generation than Current Practice 1, which increases the volume of both market purchases and market sales because California ratepayers buy more in off-peak hours (due to less wind) and sell more in on-peak hours (due to more solar). Elimination of transmission charges and bilateral trading hurdles within the market region contributes to a higher volume of market purchases and sales. The large increase in the amount of market purchases leads to higher purchase costs. However, this is more than offset by the reduction in production costs of owned and contracted generation and higher sales revenues, resulting in net overall savings of $104 million/year.
- In Regional 3, the amount of market purchases does not increase as much as in Regional 2. This is partly due to the differences in renewable portfolio (Regional 3 has more wind and less solar, so the volume effects described above work in the other direction). In addition, in Regional 3, CAISO entities procure less renewables from "REC only" resources so they

have more energy supplied from "bundled" renewable resources. As a result, the net overall savings in Regional 3 is estimated to be $523 million, which is significantly above the savings estimated under Regional 2. (Note that higher operating-cost savings in Regional 3 are partially offset by the lower PPA costs of "REC only" resources compared to "bundled" resources, which is reflected in E3's analysis.)

Figure 40: 2030 California Annual Net Power Production, Purchases, and Sales Costs

	GWh			$/MWh			$MM/yr		
	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CAISO TEAM Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	199,214	200,382	202,589	$16.6	$16.4	$16.1	$3,312	$3,283	$3,254
Cost of CAISO-Internal Market Purchases	49,572	42,774	39,307	$59.4	$59.7	$59.0	$2,945	$2,553	$2,317
Cost of CAISO Market Imports	4,664	15,254	14,355	$59 2	$56.6	$54.3	$276	$864	$780
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,136)	(10,978)	$4 8	$17.7	$23.6	($39)	($233)	($259)
Cong. Revenues from Export of Merchant Gen							$0	($2)	$3
TOTAL	**245,273**	**245,273**	**245,273**	**$26.5**	**$26.4**	**$24.8**	**$6,495**	**$6,466**	**$6,094**
Impact of Regionalization								($29)	($400)
								(0.4%)	(6.2%)
Rest of California APC Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	51,420	48,775	48,457	$20.4	$18.2	$17.9	$1,051	$888	$865
Cost of Market Purchases	12,525	14,854	14,921	$57.1	$54.5	$52.8	$715	$810	$788
Revenues from Market Sales	(6,740)	(6,424)	(6,173)	$29 0	$31.3	$33.1	($195)	($201)	($204)
TOTAL	**57,205**	**57,205**	**57,205**	**$27.5**	**$26.2**	**$25.3**	**$1,572**	**$1,497**	**$1,449**
Impact of Regionalization								($75)	($123)
								(4 8%)	(7.8%)
Total California Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	250,634	249,157	251,046	$17.4	$16.7	$16.4	$4,363	$4,171	$4,119
Cost of Market Purchases	66,760	72,882	68,583	$59 0	$58.0	$56.6	$3,937	$4,227	$3,885
Revenues from Market Sales	(14,916)	(19,560)	(17,151)	$15.7	$22.3	$26.9	($234)	($436)	($461)
TOTAL	**302,478**	**302,478**	**302,478**	**$26.7**	**$26.3**	**$24.9**	**$8,066**	**$7,962**	**$7,544**
Impact of Regionalization								**($104)**	**($523)**
								(1.3%)	**(6.5%)**

The regional market benefits depend significantly on energy prices during oversupply and renewable curtailment conditions. In the Current Practice 1 scenario, the bilateral trading hurdles limit exports of California renewable generation portfolios in hours with low load and high wind and solar output. This results in renewable curtailments and very low or even negative market prices, which represent a significant additional cost to California ratepayers when selling power during oversupply conditions. Exactly how low or negative these prices can be depends on market conditions, the structure of renewable contracts, the availability of production tax credits, and bilateral counterparties' willingness to buy. Generally, prices will reach negative levels equal to the seller's opportunity cost of curtailments. If, for example, a curtailment means the utility loses $40/MWh because it (a) has to compensate the seller for the lost production tax credits or (b) has to purchase replacement renewables attributes, then the utility would be willing to settle on a price as low as -$40/MWh (*i.e.*, it is better off to pay someone to take the power than to be curtailed).

As discussed earlier, the simulations for the Regional 2 and Regional 3 scenarios show that the regional market reduces the effects of oversupply, which is reflected in lower curtailments and reduced frequency of low- or negatively-priced periods. In our baseline scenarios, we conservatively assumed that the settlement prices do not drop below zero (*i.e.*, California entities would give oversupply power away for free, but not pay buyers to take that power). By constraining these prices to zero, we conservatively omit a significant potential cost that would likely be incurred in the Current Practice scenario but less in the Regional ISO scenarios, due to lower curtailments in the Regional ISO scenarios.

At negative market prices—consistent with the recent experience in CAISO during periods with high solar generation,[36] at Mid-C during high hydro and low load periods, and in other markets, such as ERCOT, MISO, and SPP that have been experiencing renewable generation oversupply conditions—California would have to pay counterparties to take the exported power. To demonstrate the effects of negative pricing, we ran a sensitivity that assumes a negative $40/MWh price floor (roughly based on marginal REC costs estimated by the RESOLVE model).

Figure 41 below summarizes the results of this negative price sensitivity, with savings of $237 million/year under Regional 2 and $731 million/year under Regional 3.

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36 Negative prices are now being experienced in the CAISO footprint. Seven percent of all 5-minute real-time pricing intervals has experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation and relatively low loads. Although some prices ranged between negative $30/MWh and negative $150/MWh, in most of the periods, the negative prices remained above negative $30/MWh. (See CAISO Internal Market Monitor "Q1 2016 Report on Market Issues and Performance.")

Figure 41: 2030 California Annual Net Power Production, Purchases, and Sales Costs (Sensitivity: Negative $40/MWh price floor)

	GWh			$/MWh			$MM/yr		
	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CAISO TEAM Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	199,214	200,382	202,589	$16.6	$16.4	$16.1	$3,312	$3,283	$3,254
Cost of CAISO-Internal Market Purchases	49,572	42,774	39,307	$59.4	$59.7	$59.0	$2,945	$2,553	$2,317
Cost of CAISO Market Imports	4,664	15,254	14,355	$59 2	$56.6	$54.3	$276	$864	$780
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,136)	(10,978)	($24.1)	$8.2	$18.9	$197	($108)	($207)
Add'l Market Sales to Match RESOLVE Curtailments							($13)	($45)	($46)
Cong. Revenues from Export of Merchant Gen							$0	$2	$7
TOTAL	**245,273**	**245,273**	**245,273**	**$27.4**	**$26.7**	**$24.9**	**$6,718**	**$6,549**	**$6,105**
Impact of Regionalization								($169)	($613)
								(2 5%)	(9.1%)
Rest of California APC Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	51,420	48,775	48,457	$20.4	$18.2	$17.9	$1,051	$888	$865
Cost of Market Purchases	12,525	14,854	14,921	$57.1	$54.5	$52.7	$715	$810	$787
Revenues from Market Sales	(6,740)	(6,424)	(6,173)	$28.7	$29.9	$32.0	($194)	($192)	($197)
TOTAL	**57,205**	**57,205**	**57,205**	**$27.5**	**$26.3**	**$25.4**	**$1,573**	**$1,505**	**$1,455**
Impact of Regionalization								($68)	($118)
								(4 3%)	(7.5%)
Total California Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	250,634	249,157	251,046	$17.4	$16.7	$16.4	$4,363	$4,171	$4,119
Cost of Market Purchases	66,760	72,882	68,583	$59 0	$58.0	$56.6	$3,937	$4,227	$3,884
Revenues from Market Sales	(14,591)	(18,460)	(16,019)	$0.6	$18.6	$27.7	($9)	($343)	($444)
TOTAL	**302,803**	**303,579**	**303,610**	**$27.4**	**$26.5**	**$24.9**	**$8,291**	**$8,054**	**$7,560**
Impact of Regionalization								**($237)**	**($731)**
								(2.9%)	**(8.8%)**

g. CO_2 Emissions from the Electricity Sector

Compared to historical levels, our simulations show significant reductions in CO_2 emissions from the electricity sector, both in California and WECC-wide. Figure 42 summarizes the annual CO_2 emissions results across all five baseline scenarios simulated. The 2020 simulations of regional markets (CAISO+PAC) show a slight increase, though essentially almost no change in CO_2 emissions relative to Current Practice. In 2030, the expanded regional market (WECC without PMAs) is estimated to decrease CO_2 emissions to serve California's load by 4–5 million tonnes (8-9% of total) and decrease CO_2 emissions in the WECC by 10-11 million tonnes (around 3.5 % of total) relative to the 2030 Current Practice 1 scenario.

Figure 42 shows a slight reduction in startup-related emissions under the regional market scenarios, although this impact is likely understated for a number of reasons. The production cost model captures variation in generator emissions during startup and across changes in generator output (*i.e.*, the simulated heat rate curve captures that generators produce higher emissions when operating at partial load levels), but modest additional emissions impacts due to inefficiencies during unit ramping periods were not simulated. A regional market will reduce the magnitude and frequency of generation unit cycling. As such, not modeling the additional emissions impact during unit ramping likely results in a more conservative estimate of the emissions reductions achieved by a regional market.

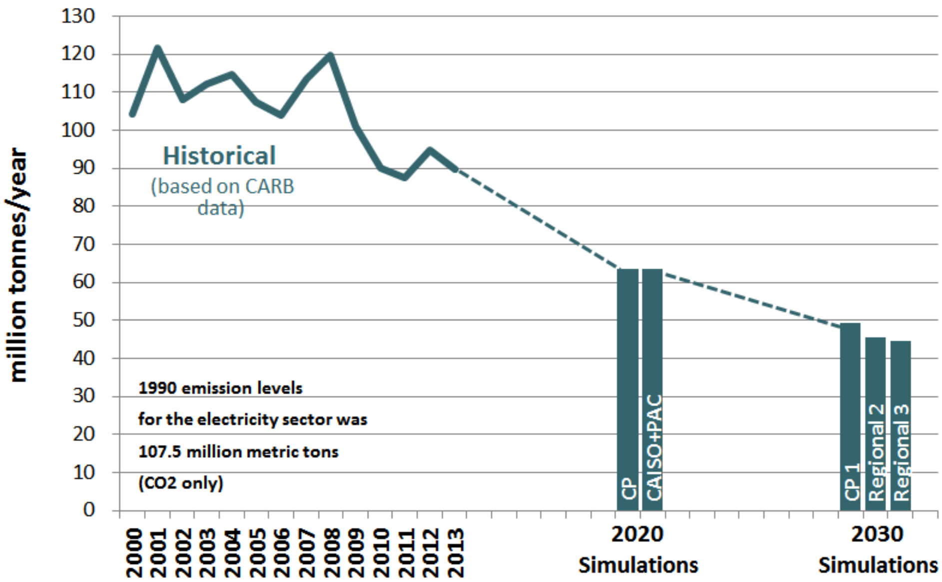
Figure 42: Summary of Annual California and WECC-Wide CO_2 Emissions

	2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CA In-State w/o Startup	51.7	51.5	45.8	44.2	43.0
+ Startup	0.2	0.1	0.4	0.3	0.3
CA In-State Total	**51.8**	**51.6**	**46.2**	**44.5**	**43.3**
CA Imports Contracted	9.1	8.6	6.2	4.1	3.4
CA Imports Generic	3.2	4.0	1.7	1.8	1.5
CA Exports Generic	(0.4)	(0.7)	(4.8)	(4.9)	(3.7)
CA Emissions for Load	**63.6**	**63.6**	**49.2**	**45.5**	**44.6**
Impact of Regionalization		(0.1) (0.1%)		(3.7) (7.6%)	(4.6) (9.4%)
WECC-wide w/o Startup	330.3	330.9	305.7	294.6	296.3
+ Startup	1.0	1.0	1.5	1.3	1.2
WECC TOTAL	**331.3**	**331.9**	**307.3**	**295.9**	**297.5**
Impact of Regionalization		0.6 0.2%		(11.4) (3.7%)	(9.8) (3.2%)

* Calculations for California assume that CO_2 emissions associated with imports are charged (and exports are credited) based on a generic emissions rate for natural gas CCs.

As shown in Figure 43, the electric-sector emissions in California decline substantially from historical levels, by about 30% in 2020 and 45–55% in 2030 compared to actual emissions in 2013.

Figure 43: Simulated vs. Historical CO_2 Emissions from the Electricity Sector in California



Overall, the impact of a regional market on electric-sector CO_2 emissions in California and the rest of U.S. WECC would depend on the magnitude of future coal retirements throughout the U.S. WECC, mechanisms for complying with the EPA's Clean Power Plan (and interactions with California's GHG cap-and-trade program), and the degree of renewable deployment beyond RPS due to the regional market. We have conducted sensitivity analyses to estimate some of these impacts, which are discussed in the next section, Section 2.

2. Sensitivity Analyses

a. 2020 Regional ISO Sensitivity

We simulated 2020 with a broad regional footprint that includes all of the U.S. WECC except for the federal Power Marketing Agencies to evaluate impacts of the larger regional market under near-term market conditions.

As shown Figure 44, the broad regional footprint provides WECC-wide production cost savings of \$171 million (1.1%) in 2020. These savings are about ten times larger than the \$18 million estimated under the 2020 CAISO+PAC scenario. The annual CO_2 emissions remain about the same in California, and increase slightly for the WECC as a whole (by around 0.8%). As in the CAISO+PAC case, the simulations artificially advantage coal dispatch through the generic gas CC-based CO_2 hurdle rate imposed on all imports into California (rather than applying a coal-specific carbon import charge). This magnifies the extent to which coal dispatch and related emissions are impacted in the simulations. As discussed in the context of coal dispatch in Volume I, the small increase in 2020 WECC-wide CO_2 emissions is overstated because of simplified modeling assumptions.

Figure 44: Production Cost and CO_2 Emission Impacts of the Regional Market 2020 Regional ISO Sensitivity Compared to 2020 Current Practice Scenario

(a) Annual WECC-Wide Production Costs in 2016 $million/yr

	2020 Current Practice	2020 Regional ISO
Fuel cost	$14,316	$14,206
Start-up cost	$436	$363
Variable O&M cost	$1,380	$1,393
TOTAL	**$16,133**	**$15,961**
Impact of Regionalization		($171)
		(1.1%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2020 Current Practice	2020 Regional ISO
CA In-State	51.8	51.8
CA Imports Contracted	9.1	7.5
CA Imports Generic	3.2	4.6
CA Exports Generic	(0.4)	(0.4)
CA Emissions for Load	**63.6**	**63.5**
Impact of Regionalization		(0.1)
		(0.2%)
WECC TOTAL	**331.3**	**334.1**
Impact of Regionalization		2.8
		0.8%

Figure 45 summarizes California's production, purchases, and sales costs that are included as a part of the ratepayer impact analysis. With the larger regional footprint in 2020, the estimated annual state-wide savings increase to $97 million, which is approximately ten times higher than the savings of $10 million under the CAISO+PAC scenario. Increased savings in the 2020 Regional ISO Sensitivity is driven by more efficient dispatch of in-state resources and higher revenues from exports during hours with excess renewable generation.

Figure 45: California Annual Net Power Production, Purchases, and Sales Costs 2020 Regional ISO Sensitivity Compared to 2020 Current Practice Scenario[37]

	GWh		$/MWh		$MM/yr	
	2020 Current Practice	2020 Regional ISO	2020 Current Practice	2020 Regional ISO	2020 Current Practice	2020 Regional ISO
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	166,736	167,411	$17.8	$17 9	$2,966	$2,993
Cost of CAISO-Internal Market Purchases	67,573	64,613	$44.6	$44.6	$3,015	$2,883
Cost of CAISO Market Imports	4,889	7,227	$48.1	$45 9	$235	$332
Revenues from Exports of Owned & Contracted Gen	(417)	(471)	$1.8	$22 0	($1)	($10)
Cong. Revenues from Export of Merchant Gen					($0)	($4)
TOTAL	**238,781**	**238,781**	**$26.0**	**$25.9**	**$6,216**	**$6,193**
Impact of Regionalization						($23)
						(0.4%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	39,422	36,346	$23.1	$20 8	$909	$757
Cost of Market Purchases	15,927	18,900	$44.9	$42 3	$715	$800
Revenues from Market Sales	(3,437)	(3,334)	$33.5	$36.7	($115)	($122)
TOTAL	**51,912**	**51,912**	**$29.1**	**$27.6**	**$1,509**	**$1,435**
Impact of Regionalization						($74)
						(4 9%)
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	206,158	203,758	$18.8	$18.4	$3,875	$3,750
Cost of Market Purchases	88,389	90,740	$44.9	$44 2	$3,965	$4,015
Revenues from Market Sales	(3,854)	(3,805)	$30.2	$36 0	($116)	($137)
TOTAL	**290,693**	**290,693**	**$26.6**	**$26.2**	**$7,724**	**$7,628**
Impact of Regionalization						**($97)**
						(1.3%)

b. 2030 Current Practice 1B Sensitivity

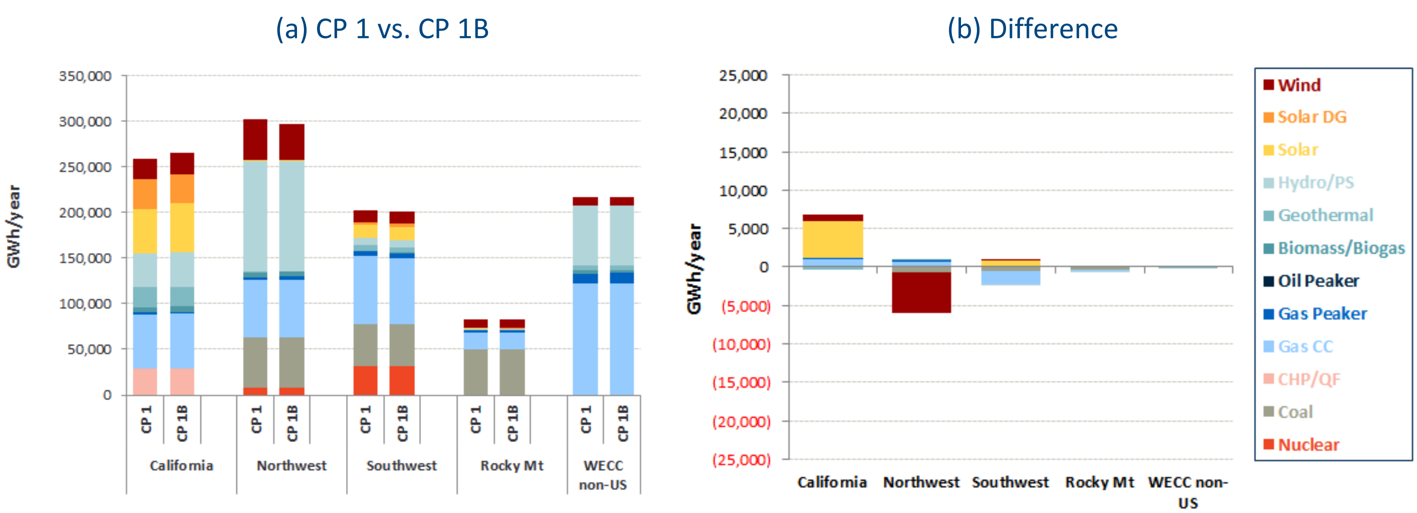
In the 2030 Current Practice 1B Sensitivity, we assumed that bilateral markets have higher flexibility to manage oversupply conditions, absent a Regional ISO. This case was requested by stakeholders following the February 8, 2016 stakeholder workshop. In response, the study team included this case as a sensitivity, but the study team does not believe it is likely that this level of flexibility could be achieved without a regional market. Absent a day-ahead market with coordinated regional unit commitment and dispatch, it is unlikely that other balancing areas would have the flexibility within their systems to take on upwards of 16,000 MW of renewable generation oversupply in real-time or that bilateral trading (which consists in large part of trading 16-hour blocks of power on a day-ahead basis) would be sufficiently flexible to trade such large amounts of intermittent energy on an intra-day, hourly, and sub-hourly basis.

[37] The results under 2020 Current Practice differ slightly from those in Figure 39 due to changes in exclusion hours that are determined jointly as the hours with simulated LMPs higher than $500/MWh across the scenarios compared.

To implement the high-bilateral-flexibility Sensitivity under a 2030 bilateral market structure in PSO, we increased CAISO's net bilateral export limit from 2,000 MW to 8,000 MW for the Current Practice 1B case. Additionally, we incorporated a "re-optimized" 50% RPS portfolio for California based on E3's analysis of this 1B case, which includes less renewable capacity compared to Current Practice 1 to reflect the reduced need to "over-build" resources in order to make up for curtailed energy. The overall portfolio has more solar resources procured in California and less wind resources out of state.

Figure 46 below shows the effect of these changes to the Current Practice scenario on simulated generation results. (The implications on the overall ratepayer impacts of a regional market compared to this high-bilateral-flexibility Current Practice 1B Sensitivity is presented in Volumes I and VII of this report.)

Figure 46: Differences in Generation Due to Higher Bilateral Flexibility
2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario



Compared to the less flexible Current Practice 1 scenario, most of the differences in generation output shown in Figure 46 are due to differences in the renewable portfolios. Even though less renewable capacity is built in the Current Practice 1B case than in Current Practice 1, the total renewable energy output is similar between the two sets of simulations because of differences in curtailment levels.

Figure 47 below illustrates how these changes in unit dispatch in the two Current Practice cases would change WECC-wide production costs and WECC-wide and California CO_2 emissions. Again, this figure compares the high-bilateral-flexibility Sensitivity 1B to Current Practice 1.

Figure 47: Production Cost and CO_2 Emission Impacts of Higher Bilateral Flexibility 2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Current Practice 1B
Fuel cost	$17,602	$17,600
Start-up cost	$769	$816
Variable O&M cost	$1,188	$1,184
TOTAL	**$19,559**	**$19,600**
Difference		$41 0.2%

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1	2030 Current Practice 1B
CA In-State	46.2	46.6
CA Imports Contracted	6.2	6.1
CA Imports Generic	1.7	1.8
CA Exports Generic	(4.8)	(7.0)
CA Emissions for Load	**49.2**	**47.5**
Difference		(1.7) (3.4%)
WECC TOTAL	**307.3**	**306.3**
Difference		(0.9) (0.3%)

With similar amounts of total renewable energy output (net of curtailments), the WECC-wide production costs in the high-bilateral Sensitivity 1B is estimated to be slightly higher (by $41 million, or 0.2%) compared to Current Practice 1. (It also means Sensitivity 1B yields $41 million lower production cost savings when compared to the Regional 2 and Regional 3 scenarios as discussed further in Volume VII).

Compared to Current Practice 1, the slightly higher costs in Sensitivity 1B are driven by the higher startup costs incurred to accommodate increased variability associated with additional solar generation in California's RPS portfolio. The CO_2 emissions decrease under Sensitivity 1B (relative to Current Practice 1) by 1.7 million tonnes in California (3.4%) and 0.9 million tonnes WECC-wide (0.3%). The reduction in California's emissions is largely due to increased emissions credits from renewable energy exports during oversupply conditions. In Sensitivity 1B, California is assumed to procure less renewables from out-of-state "REC only" resources and more renewables from "bundled" resources, consistent with E3's portfolio analysis.

Figure 48 compares the results for California's production, purchases, and sales costs against the baseline scenario. Net annual state-wide customer costs increase slightly by $49 million in the Current Practice 1B sensitivity compared to Current Practice 1, primarily driven by the portfolio effects. (Again, this difference of $49 million would yield lower ratepayer impacts when compared to the Regional 2 and Regional 3 scenarios as shown in Volumes I and VII).

Figure 48: California Annual Net Power Production, Purchases, and Sales Costs 2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario[38]

	GWh		$/MWh		$MM/yr	
	2030 Current Practice 1	2030 Current Practice 1B	2030 Current Practice 1	2030 Current Practice 1B	2030 Current Practice 1	2030 Current Practice 1B
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	199,214	203,549	$16.6	$16 3	$3,312	$3,327
Cost of CAISO-Internal Market Purchases	49,572	50,291	$59.4	$59.7	$2,945	$3,003
Cost of CAISO Market Imports	4,664	4,887	$59.2	$61 0	$276	$298
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,454)	$4.8	$6.7	($39)	($90)
Cong. Revenues from Export of Merchant Gen					$0	$1
TOTAL	**245,273**	**245,273**	**$26.5**	**$26.7**	**$6,495**	**$6,539**
Difference						$44
						0.7%
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	51,420	51,256	$20.4	$20.7	$1,051	$1,060
Cost of Market Purchases	12,525	12,438	$57.1	$56 9	$715	$707
Revenues from Market Sales	(6,740)	(6,489)	$29.0	$29.4	($195)	($191)
TOTAL	**57,205**	**57,205**	**$27.5**	**$27.6**	**$1,572**	**$1,577**
Difference						$5
						0 3%
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	250,634	254,805	$17.4	$17 2	$4,363	$4,387
Cost of Market Purchases	66,760	67,616	$59.0	$59 3	$3,937	$4,008
Revenues from Market Sales	(14,916)	(19,943)	$15.7	$14.0	($234)	($280)
TOTAL	**302,478**	**302,478**	**$26.7**	**$26.8**	**$8,066**	**$8,115**
Difference						**$49**
						0.6%

Compared to Current Practice 1, Sensitivity 1B has less renewables from out-of-state "REC only" resources and more renewables from "bundled" resources, California has higher generation from owned and contracted resources, and the state exports more energy (especially during daytime when solar generation is high) at higher prices, which reduces customer costs. However, California buys more energy during off-peak hours after the sunset when there is no solar generation. With less wind generation, the simulated prices for market purchases and imports increase slightly, which results in higher purchase costs more than offsetting the costs reductions associated with export revenues.

c. 2030 Regional ISO 1 Sensitivity

To isolate the effects of a regional market from changes in the renewable portfolio (*i.e.*, without re-optimizing the renewable portfolio assumptions), we simulated a regional market with exactly the same renewable resources portfolio that was selected for the Current Practice 1 baseline scenario (and without additional renewables beyond RPS). As in Regional 2 and Regional 3, the

[38] Calculations conservatively assume that the settlement prices do not drop below $0/MWh.

CAISO's physical net export limit is set to 8,000 MW, reserve requirements are reduced, and reserve sharing is permitted. As shown in Figure 49, this Regional ISO 1 sensitivity has more renewable generation compared to Current Practice 1 because it starts with the same amount of "over-build" but has much fewer curtailments. Higher renewables output in combination with removed hurdle rates and increased reserve sharing arrangements displace more fossil-fuel generation and allow for dispatch switching (mostly from less to more efficient gas-fired plants) in the region.

Figure 49: Generation Impacts of the Regional Market
2030 Regional ISO 1 Sensitivity Compared to Current Practice 1 Baseline Scenario

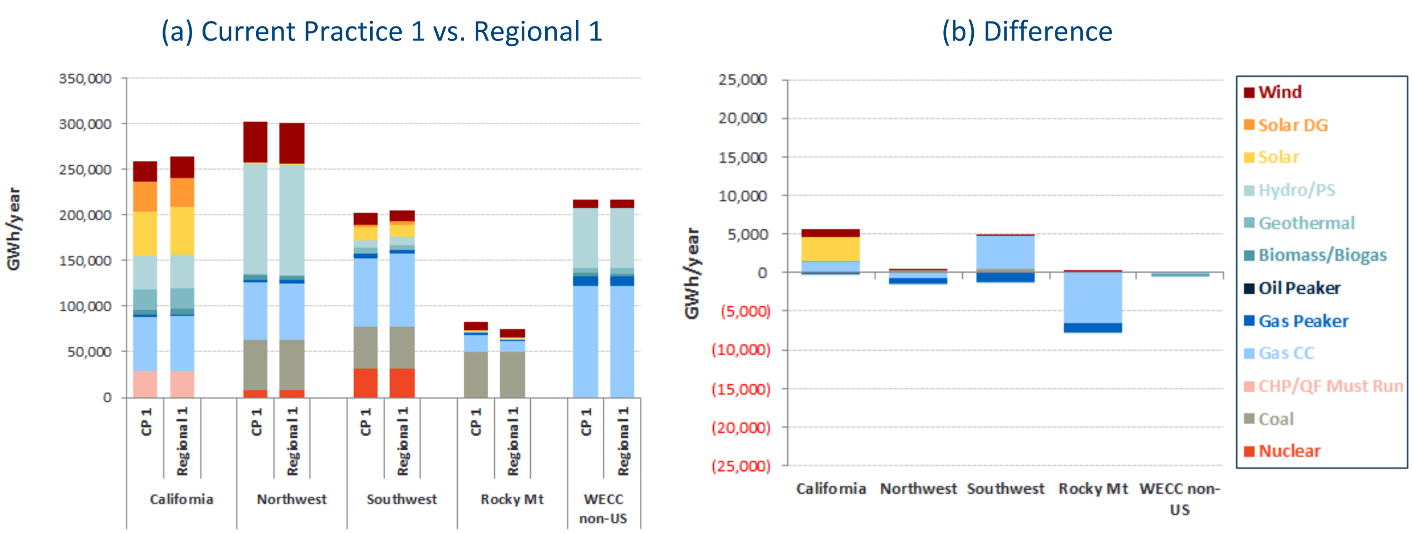


Figure 50 summarizes the 2030 production costs and CO_2 emissions impacts for the Regional ISO 1 sensitivity and the Current Practice 1 baseline scenario. With fewer curtailments and higher renewable output, the 2030 regional market simulated in this sensitivity is estimated to provide WECC-wide production cost savings of $388 million (2% of total) and reduce annual CO_2 emissions by 2.2 million tonnes in California (4.5%) and 2.9 million tonnes WECC-wide (0.9%) compared to the Current Practice 1 baseline.

Figure 50: Production Cost and CO_2 Emission Impacts of the Regional Market
2030 Regional ISO 1 Sensitivity Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Regional ISO 1
Fuel cost	$17,602	$17,320
Start-up cost	$769	$666
Variable O&M cost	$1,188	$1,185
TOTAL	**$19,559**	**$19,171**
Impact of Regionalization		($388)
		(2.0%)

(b) Annual CO_2 Emissions in million tonnes/yr

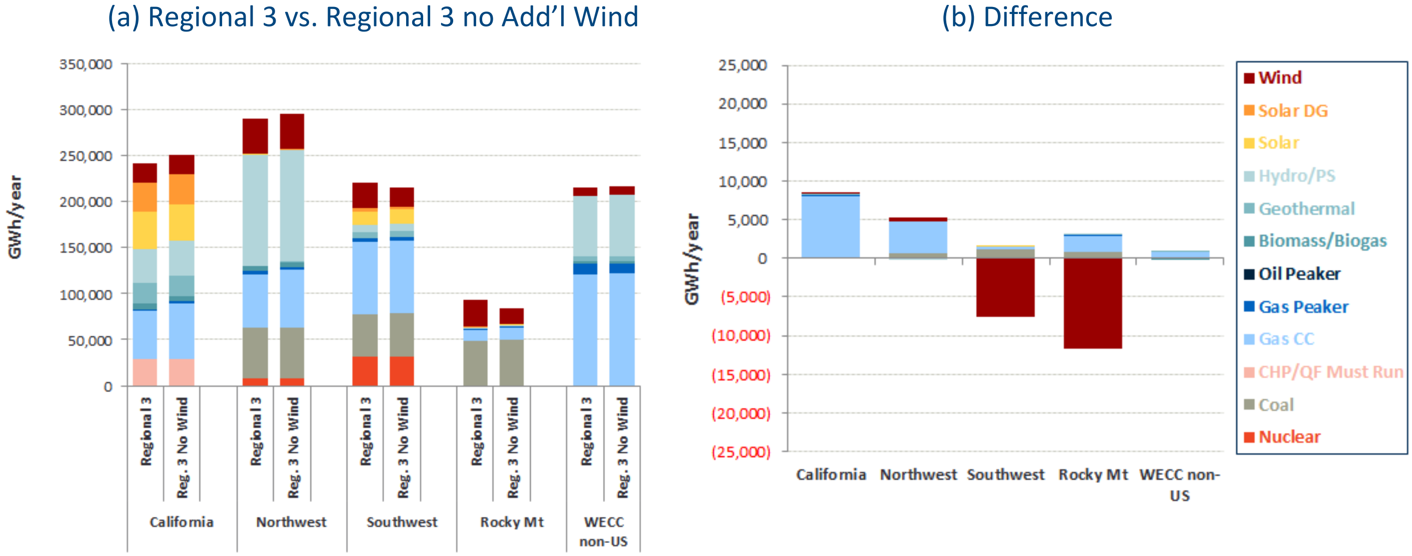
	2030 Current Practice 1	2030 Regional ISO 1
CA In-State	46.2	46.4
CA Imports Contracted	6.2	5.3
CA Imports Generic	1.7	2.8
CA Exports Generic	(4.8)	(7.5)
CA Emissions for Load	**49.2**	**47.0**
Impact of Regionalization		(2.2)
		(4.5%)
WECC TOTAL	**307.3**	**304.4**
Impact of Regionalization		(2.9)
		(0.9%)

This Regional ISO 1 sensitivity focused primarily on impacts on generation and CO_2 emissions. Accordingly, we did not perform the TEAM calculations to estimate California's production, purchases, and sales costs.

d. 2030 Regional ISO 3 without Renewables Beyond RPS

We simulated the 2030 Regional 3 scenario without the additional 5,000 MW of beyond-RPS wind generation facilitated by the regional market to isolate the impacts of regionalization when no renewables beyond RPS are developed. Figure 51 compares the generation results for the simulations of Regional 3 with and without the additional beyond-RPS wind generation. Integrating 5,000 MW of additional wind generation displaces annual WECC-wide fossil-fuel generation (both gas and coal) by approximately 18,300 GWh per year. About 8,200 GWh of the displaced energy (44%) is estimated to be from the natural gas-fired units in California assuming that no CO_2 hurdle would be imposed on imports from the additional wind sources located in Wyoming and New Mexico into California.

Figure 51: Generation Impacts of 5,000 MW Beyond-RPS Renewables On the Regional ISO 3 Scenario



Even without the 5,000 MW of additional wind generation beyond RPS, the regional market is estimated to provide significant production cost savings and CO_2 emission reductions. As summarized in Figure 52, the annual production costs decrease by $335 million (1.7%) compared to Current Practice 1, which corresponds to approximately 1/3 of the production cost impacts estimated in the simulations with the additional wind generation. The annual CO_2 emissions associated with serving California's load decrease by 2.1 million tonnes (4.5%) overall when considering both imports and exports, but CO_2 emissions from in-state resources increase slightly (though that increase is more than offset by reduced emissions from contracted out-of-state resources and credits for net exports). The annual CO_2 emissions decrease on a WECC-wide basis by around 1.3 million tonnes (0.4%).

Figure 52: Production Cost and CO_2 Emission Impacts of the Regional Market 2030 Regional ISO 3 Sensitivity without Renewables Beyond RPS Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Regional ISO 3 No Add'l Wind
Fuel cost	$17,602	$17,412
Start-up cost	$769	$622
Variable O&M cost	$1,188	$1,190
TOTAL	**$19,559**	**$19,224**
Impact of Regionalization		($335) (1.7%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1	2030 Regional ISO 3 No Add'l Wind
CA In-State	46.2	46.5
CA Imports Contracted	6.2	4.6
CA Imports Generic	1.7	2.3
CA Exports Generic	(4.8)	(6.3)
CA Emissions for Load	**49.2**	**47.1**
Impact of Regionalization		(2.1) (4.3%)
WECC TOTAL	**307.3**	**306.0**
Impact of Regionalization		(1.3) (0.4%)

Figure 53 summarizes the results for California's production, purchases, and sales costs without additional renewables beyond RPS. The annual savings associated with the regional market are estimated to be $500 million, which is only slightly lower compared to the $523 million estimated under the baseline simulations. California cost savings remain similar with or without the additional renewables because these renewable resources are assumed to be developed on a merchant basis and they are not contracted by California entities. The slight decrease in savings is due to the price effects of renewables. Without the 5,000 MW of wind generation, the simulated market prices are slightly higher during hours when California is a net purchaser compared to the with wind case.

Figure 53: California Annual Net Power Production, Purchases, and Sales Costs 2030 Regional ISO 3 Sensitivity without Renewables Beyond RPS Compared to Current Practice 1 Baseline Scenario[39, 40]

	GWh		$/MWh		$MM/yr	
	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	200,461	205,700	$16.6	$16 3	$3,333	$3,356
Cost of CAISO-Internal Market Purchases	49,963	45,948	$59.6	$59 0	$2,979	$2,713
Cost of CAISO Market Imports	4,713	6,417	$59.5	$59 2	$280	$380
Revenues from Exports of Owned & Contracted Gen	(8,206)	(11,135)	$4.8	$25.7	($39)	($286)
Cong. Revenues from Export of Merchant Gen					$0	$3
TOTAL	**246,930**	**246,930**	**$26.5**	**$25.0**	**$6,553**	**$6,166**
Impact of Regionalization						($387)
						(5 9%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	51,763	49,611	$20.5	$18 5	$1,059	$918
Cost of Market Purchases	12,608	14,242	$57.3	$54.1	$722	$771
Revenues from Market Sales	(6,766)	(6,248)	$29.0	$34.7	($196)	($217)
TOTAL	**57,605**	**57,605**	**$27.5**	**$25.5**	**$1,584**	**$1,472**
Impact of Regionalization						($113)
						(7.1%)
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	252,224	255,311	$17.4	$16.7	$4,392	$4,274
Cost of Market Purchases	67,284	66,607	$59.2	$58 0	$3,981	$3,864
Revenues from Market Sales	(14,647)	(16,251)	$16.1	$30 8	($235)	($500)
TOTAL	**304,861**	**305,667**	**$26.7**	**$25.0**	**$8,138**	**$7,638**
Impact of Regionalization						**($500)**
						(6.1%)

e. 2030 Current Practice 1 and Regional 3 Scenarios with a CO_2 Price in the Rest of WECC

We simulated the 2030 scenarios with a $15/tonne CO_2 price across the rest of the U.S. WECC outside of California as a proxy for compliance with EPA's Clean Power Plan. This sensitivity shows one possible path to CPP compliance in the rest of U.S. WECC, but is not meant to reflect any more or less "likely" impact of CPP implementation by other WECC states in either the baseline or the regional market simulations.

39 Calculations conservatively assume that settlement prices do not drop below $0/MWh.

40 The results under 2030 Current Practice 1 differ slightly from those in Figure 40 due to changes in exclusion hours that are determined jointly as the hours with simulated LMPs higher than $500/MWh across the scenarios compared.

Under the final plan, CPP sets state-specific emissions targets, covering coal-fired plants, natural gas-fired combined-cycle plants, and some cogeneration facilities larger than 25 MW. With our WECC CO_2 pricing simulations we estimate that California will comply with CPP in all of the scenarios examined. However, as shown in Figure 54, despite significant coal plant retirements through 2030, the rest of U.S. WECC does not comply with CPP in the 2030 baseline Current Practice 1 simulations without a CO_2 price outside of California. (See negative value for the difference between CPP target and simulated emissions, shown in red, for the 2030 Current Practice 1 results.) In contrast, with a CO_2 price of $15/tonne, the emissions from rest of U.S. WECC would drop below the mass-based CPP target (for both existing units and existing units *plus* new gas-fired CCs). (Positive values for the difference between CPP target and simulated emissions for both $15/tonne Sensitivities.) With the further CO_2 emissions reductions offered in the regional market simulations, the results indicate that CPP compliance could be achieved at a lower cost with a regional market.

Figure 54: Compliance with Mass-Based Clean Power Plan (CPP) Standard With and Without Covering New Gas CC Units
(million tonne/yr)

	2030 Mass-based Target	2030 Current Practice 1	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
Existing Units				
California	**43.9**	**27.2**	**27.6**	**26.2**
Target – Simulated		*16.7*	*16.3*	*17.8*
Rest of WECC U.S.	**179.3**	**183.8**	**164.4**	**156.6**
Target – Simulated		*(4.5)*	*14.9*	*22.7*
Existing + New Units				
California	**47.9**	**27.6**	**28.0**	**26.6**
Target – Simulated		*20.4*	*19.9*	*21.3*
Rest of WECC U.S.	**191.3**	**201.8**	**185.6**	**179.1**
Target – Simulated		*(10.5)*	*5.8*	*12.2*

Figure 55 shows the impact of the CO_2 prices on generation results on the Current Practice 1 case. Even applying the modest $15/tonne CO_2 price to the rest of the U.S. WECC outside of California results in coal-to-gas dispatch switching of approximately 27,000 GWh/year in our 2030 simulations, yielding CO_2 emissions reductions that exceed those needed for CPP compliance. In

California, generation levels do not change much because the CO_2 costs associated with serving California's load are kept the same (based on the $45.8/tonne assumed under AB 32). There is a slight increase in-state gas generation (by about 1.4%) due to reduced CO_2 charges for market imports because of the lower CO_2 price differential between California and the rest of WECC region.

Figure 55: Generation Impacts of a $15/tonne CO_2 Price in the U.S. WECC Outside California 2030 Current Practice 1 CO_2 Sensitivity Compared to Current Practice 1 Baseline Scenario

(a) Current Practice 1 vs. Current Practice 1 with $15/tonne

(b) Difference

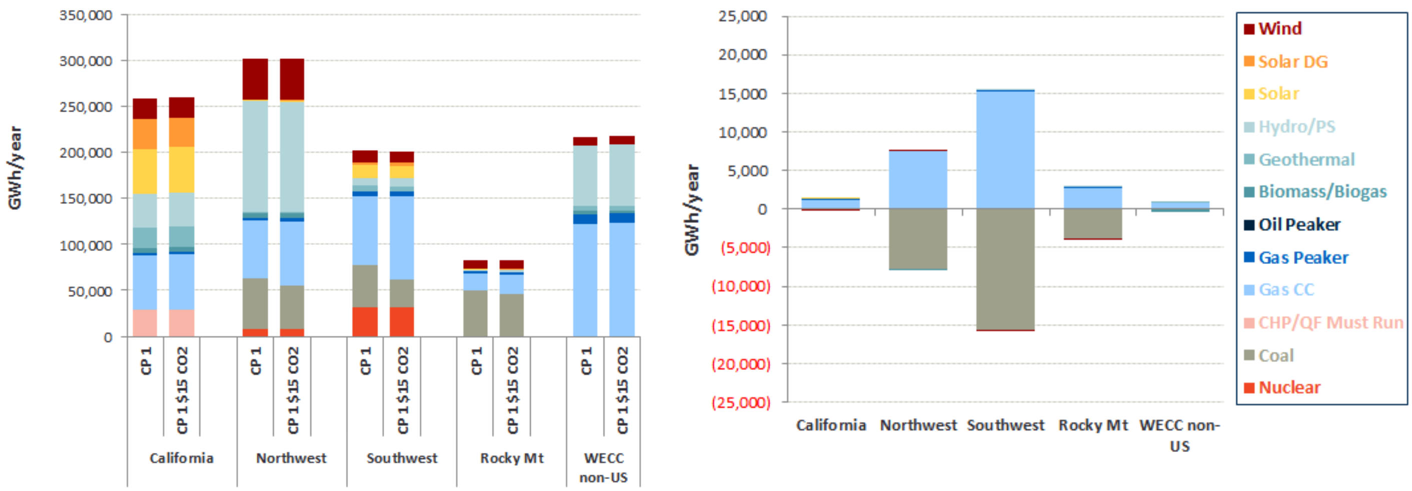


Figure 56 summarizes the production cost savings and CO_2 emissions impacts of the regional market for a $15/ton CO_2 price applied to the rest of WECC in both Current Practice 1 and Regional 3 scenarios. The estimated WECC-wide production cost savings of the regional market are $971 million (4.9%), which is similar to the savings estimated under the baseline simulations. These savings do not include any cost reductions associated with CO_2 emissions. Doing so would result in higher savings.

While the overall CO_2 emission levels are lower with the $15/tonne CO_2 price, the impact of regional market on California and WECC-wide CO_2 emissions (calculated based on differences between Current Practice 1 and Regional 3) are comparable to the results estimated for the baseline assumptions. A regional market decreases the annual CO_2 emissions by 4.7 million tonnes (9.6%) in California and by 10.6 million tonnes (3.6%) WECC-wide compared to the Current Practice 1 scenario. This is driven largely by fossil-fuel generation that is displaced by the additional renewable generation (beyond RPS) that is facilitated by the regional market.

Figure 56: Production Cost and CO_2 Emission Impacts of the Regional Market 2030 Current Practice 1 and Regional ISO 3 Sensitivities with WECC-Wide CO_2 Price

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
Fuel cost	$17,842	$17,074
Start-up cost	$735	$558
Variable O&M cost	$1,137	$1,110
TOTAL	**$19,713**	**$18,743**
Impact of Regionalization		($971) (4.9%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
CA In-State	46.7	44.9
CA Imports Contracted	6.4	3.8
CA Imports Generic	1.4	1.2
CA Exports Generic	(5.2)	(5.4)
CA Emissions for Load	**49.2**	**44.5**
Impact of Regionalization		(4.7) (9.6%)
WECC TOTAL	**291.2**	**280.6**
Impact of Regionalization		(10.6) (3.6%)

This sensitivity focused primarily on impacts for generation and CO_2 emissions. Accordingly, we did not perform the TEAM calculations to estimate the California's production, purchases, and sales costs.

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Senate Bill 350 Study

Volume VI: Load Diversity Analysis

PREPARED FOR

California ISO

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July 8, 2016

THE Brattle GROUP

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

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Volume VI. Load Diversity Analysis

A. Overview

Regionalization of the California ISO (ISO) would yield savings due to regional load diversity, which allows for reduced capital investments in supply resources to meet system-wide and local resource adequacy requirements. These resource adequacy-related benefits of regional market integration can be assessed from either a reliability perspective (*e.g.*, by holding generation investments constant and analyzing the benefit of improved reliability) or from an investment-cost perspective (*e.g.*, by holding the level of reliability constant and analyzing the reduction in generation investment needs).

For this study, we analyze the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity needs due to market integration. This analysis measures "load diversity" as the degree to which individual balancing area (BA) peak loads occur at different times and seasons, which leads to a coincident peak load for the combined footprint that is lower than the sum of the individual BA-internal peak loads. Figure 1 illustrates how load diversity leads to lower combined peaks. This reduction in coincident peak load is then used to estimate the generation investment cost savings offered by a regional market.[1]

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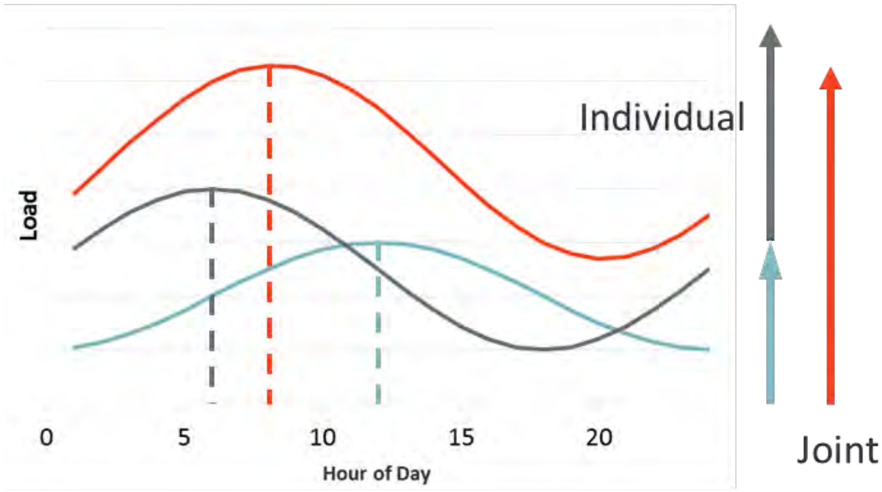
1 Energy + Environmental Economics, "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015. Available at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

Figure 1: Reduction in Capacity Due to Load Diversity



Note: Two load profiles (blue curve and grey curve) are combined to create a single joint profile (red curve). Since the peaks of the blue and grey profiles do not coincide, the peak of the joint load profile is less than the sum of the peaks of the individual profiles.

A similar methodology was used by E3 in the PAC Integration study and by Entergy in its 2011 study of the expected benefits and costs of joining MISO.[2] That such benefits are realized by members of regional markets is demonstrated by Entergy when it reported its actually-realized benefits after its first year of MISO membership.[3] MISO's own retrospective analysis confirmed the load diversity benefits of Entergy's membership. In its most recent MISO Value Proposition, the RTO found that the MISO South region, which includes Entergy, achieved $560–$750 million in load diversity benefits.[4] We use historical hourly BA loads from 2006 to 2014 to estimate typical annual peak loads and the amount of resources needed to meet the planning reserve requirement of each BA with and without a regional market. The data show that some

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2 Entergy, "An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies And Support for Proposal to Join MISO," May 12, 2011. Available at: http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=bc5c1788-4ce0-4daa-9ad0-71f09ad43643

Entergy anticipated that its capacity requirement would be 1,400 MW less (approximately 6% of peak load) as a MISO member than as a standalone entity, due to the fact that its effective reserve margin would be 12% as a MISO member, compared to 17%–20% as a standalone entity.

3 Entergy, "Estimate of MISO Savings," Presented by: Entergy Operating Companies, August 2015, Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/ICT%20Materials/ERSC/2015/20150811/20150811%20ERSC%20Item%2006%20Benefits%20of%20MISO%20Membership.pdf

4 MISO, "2015 Value Proposition Stakeholder Review Meeting," January 21, 2016, Available at: https://www.misoenergy.org/WhatWeDo/ValueProposition

BAs are summer-peaking while others are winter-peaking—and even those that peak in the same season will generally reach their peak load on different days and/or at different times of day. Capturing the benefits of this load diversity across a larger footprint through a regional market means that less generating capacity is needed on a region-wide basis. Because some BAs rely on the possibility of imports from neighboring BAs to reduce their internal resource needs, we estimate the extent to which this may already occur to derive the incremental savings that could be achieved through full coordination among all BAs within the assumed market region.

Our estimates of the load diversity benefits of a regional market are likely conservative for several reasons. First, we have not monetized the reliability-related benefits of load diversity in an integrated market (though we have discussed these benefits qualitatively in another volume). This means, for instance, that the low-end of our reported savings for PacifiCorp in 2020 are almost certainly too low. Second, our methodology does not consider the additional benefits that would accrue given the anticipated retirement of substantial existing generation in California. In a high-retirements scenario, the avoided costs in 2030 associated with load diversity could well exceed the $75/kW-year we assumed for California in that year. Third, the prospective study of Entergy joining MISO used a similar methodology to estimate load diversity benefits. After-the-fact analysis confirmed that the study had under-estimated the benefits. In fact, MISO CEO John Bear stated that the benefits achieved in the first year of Entergy joining MISO exceeded anticipated benefits by $220–$450 million.[5] Fourth, while local resource adequacy requirements may not change under regionalization, there would be opportunity to benefit from regional planning that could expand the options to solve local constraints more cost effectively. And finally, flexible capacity requirement and the cost of providing the necessary flexibility will be reduced with greater diversity of variability and loads and resources. These resource adequacy, local, and flexible capacity cost benefits are not captured in our load diversity analysis.

The next sections describe our methodology and calculations for estimating load diversity savings in the 2020 and 2030 time frames. For the 2020 case, we estimate savings for a regional market footprint consisting only of the ISO and PacifiCorp. For the 2030 case, we estimate savings for a hypothetical integrated market footprint consisting of the U.S. portion of WECC with the exception of the Federal Power Marketing Administrations ("PMAs").

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5 Watson, M. "MISO South benefits more than forecast: CEO," February 9, 2015, Platts Energy Trader, Available: https://online.platts.com/PPS/P=m&e=1423533931204.-8681191587350061510/PET_20150209.xml?artnum=c2b5a9cf9-d2ba-4195-8075-76a12fd750b7_41

B. RESULTS SUMMARY

Before discussing our methodology in detail, we first summarize our results in 2020 and 2030. In our baseline, we assumed that only the ISO and PacifiCorp would participate in the regional market in 2020. Table 1 summarizes load diversity capacity cost savings estimated in 2020 under for this scenario. In California in 2020, we used a $35/kW-year avoided cost of capacity savings, reflecting the average Resource Adequacy Requirement contract price for 2012-2016.[6] Under these assumptions, we find that regionalization leads to 184 MW of capacity savings in California, corresponding to $6 million per year.

In PacifiCorp, we assumed an avoided cost of capacity of $0-39/kW-year in 2020. The high end of this range reflects PacifiCorp's estimated brownfield cost of building two new CCs as described in the PacifiCorp Integration Study.[7] The low end of the range reflects the fact that these new plants might not have been built prior to 2020. Under these assumptions, we find that regionalization leads to savings of 776 MW for PacifiCorp, corresponding to $0 - $30 million/year in annual savings. Savings in PacifiCorp can be increased by up to 392 MW, or $15 million/year, with additional transmission capacity between PacifiCorp and CAISO.

We also considered a sensitivity case that includes a market footprint consisting of all of the U.S. WECC, except the Power Marketing Authorities (PMAs). This is the same footprint that we model in 2030. With the full regional footprint, savings in 2020 increase to 1,657 MW and $58 million/year in California (which includes all California BAs in this sensitivity case) and to 2,388 MW and $84 million/year in the rest of WECC (which now includes all of the U.S. WECC outside of California, except the PMAs).

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6 This value is based on the PAC Integration study's reported average California Resource Adequacy Requirement (RAR) Contract Price for existing generation of $34.80/kW-year for 2012–2016.

7 See p. 13 of: Energy + Environmental Economics (E3), "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015, Technical Appendix, Available: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

Table 1: 2020 Baseline Load Diversity Benefit and Annual Capacity Cost Savings

	CAISO	PacifiCorp
Capacity Benefit of Load Diversity with Current Transmission	**184 MW** (0.39%)	**776 MW** (5.86%)
Additional Capacity Savings with Transmission Upgrades	-	392 MW (2.96%)
Value of Capacity Benefit with Current Transmission ($ millions/year)	**$6MM**	**$0–30**
Additional Value of Capacity Benefit with Transmission Upgrades ($ millions/year)	-	$0–15

In 2030, we assumed that all California Balancing Authorities participated in the regional market. Additionally, the rest of the WECC, with the exception of the Canadian provinces and the PMAs, also participates. In our baseline analysis, we assumed an avoided cost of capacity of $75/kW-year in California, reflecting the fact that California will likely approach, but not yet reach, resource balance by 2030. We also report savings for avoided costs of capacity in California ranging from as low as the current Resource Adequacy contract prices ($35/kW-year) to the full Net Cost of New Entry in California ($150/kW-year).[8] In the rest of WECC, we assumed an avoided cost of capacity of $100/kW-year in our baseline analysis. We also report savings for avoided costs of capacity in the rest of WECC ranging from as low as $39/kW-year (current brownfield CC cost in PacifiCorp) to as high as $120/kW-year (nation-wide net cost of new entry).[9]

Table 2 summarizes load diversity capacity cost savings in 2030. We find that a regional market will reduce capacity requirements of California balancing areas by 1,594 MW, saving $120 million/year (with a range from $56-239 million/year). Savings in California can be increased by a further 145 MW, or $11 million/year (ranging from $5-22 million/year) with additional transmission capacity. In the rest of the region, the regional market would reduce capacity requirements by 2,665 MW, or $266 million/year (with a range of $104-320

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8 This value represents the Net Cost of New Entry (Net CONE) in California. CAISO's Department of Market Monitoring recently reported Net CONE ranging from $120 - $160/kW-yr. See p. 52-54 of http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

9 LAZARD, "Lazard's Levelized Cost of Entry Analysis – Version 9.0," November 2015, Available: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

million/year). Savings in the rest of the region can be increased by a further 1,942 MW, or $194 million/year (ranging from $76-233 million/year) with additional transmission capacity.

Table 2: 2030 Load Diversity Benefit and Annual Capacity Cost Savings

	California	**Rest of Region**
Load Diversity Benefits Already Captured	0 MW	4,481 MW
Capacity Benefit from Regional Load Diversity with Current Transmission	**1,594 MW** (2.79%)	**2,665 MW** (3.12%)
Additional Capacity Benefit with Transmission Upgrades	145 MW (0.25%)	1,942 MW (2.28%)
Capacity Cost Savings with Current Transmission ($ millions/year)	**$120** ($56–239)	**$266** ($104–320)
Additional Capacity Cost Savings with Transmission Upgrades ($ millions/yr)	$11 ($5–22)	$194 ($76–233)

C. METHODOLOGY

Our approach to estimate the capacity savings due to regional load diversity involves 4 steps:

1. Estimate how much each BA's peak load coincides with the region's peak load based on historical hourly loads, and derive the average "coincidence factor" for each BA;
2. Use BAs' stated planning reserve margins to determine each BA's planning reserve requirements as standalone entities (these planning reserve margins typically reflect capacity savings achieved by the BAs within each WECC sub-region);
3. Use the coincidence factors to estimate the capacity requirements of BAs when operating within the regional market;
4. Estimate (a) the extent to which each BA is able to achieve the identified capacity savings given the likely limits on the existing transmission grid; and (b) the additional capacity savings that would become available if our analysis underestimated the capability of the existing transmission grid or if transmission expansion were to occur in the future.

D. Estimation of Peak Load Coincidence Factors

We gathered the historical hourly load data from 2006 to 2014 for all BAs in the U.S. portion of WECC, as reported by the BAs in their FERC Form 714 filings.[10] For each year, we estimated the non-coincident peak loads for each BA and the BA's load level that is coincident with the regional market's peak load. We used the difference between the two load levels to estimate a "coincidence factor," which is defined as the ratio of the BA's share of the regional market's peak to its own internal (non-coincident) peak. We first estimate the coincidence factor of each BA for each year between 2006 and 2014[11] and then derive an approximation for a "weather normalized" coincidence factor by using the median of the annual coincidence factors for each BA. To further reduce weather-related noise in the data, the annual coincidence factors are estimated as the 4-coincident-peak ("4CP") loads, by taking each BA's internal load and regional market average load during the highest four hourly loads for each year.[12]

Next, we applied the estimated coincidence factors to projected future peak loads to estimate each BA's future load levels that are coincident with the assumed regional market's peak load in the 2020 and 2030 cases. From there, we estimated the difference between (1) the capacity requirements that each BA would need to meet its own planning reserve requirements as standalone entities; and (2) their share of the regional market's coincident peak to estimate the likely range of capacity savings in a regional market, subject to conservative estimates of how much of these savings have been captured or can be accommodated through the existing transmission grid.

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10 In addition to Canadian and Mexican BAs our analysis excluded several small BAs in the WECC for which FERC Form 714 data were not available: Arlington Valley, Constellation Energy Control and Dispatch, Gila River Maricopa Arizona, Griffith Energy, Harquahala Generating Maricopa Arizona, NaturEner Glacier Wind Energy, NaturEner West Wind.

11 As will be discussed below, for the 2030 regional market case, we calculated coincidence factors in two steps by first considering load diversity within each WECC subregion and then considering load diversity between the WECC subregions.

12 The 4CP is a recognized method for estimating peak load that minimizes the impact of minor fluctuations in weather and other factors affecting the demand for electricity from year to year. For example, the method is used by ERCOT to allocate transmission costs. See: http://www.ercot.com/content/wcm/training_courses/104/ercot_demand_response_2014_ots.pptx

E. GENERATING CAPACITY COST SAVINGS FROM LOAD DIVERSITY IN 2020

For 2020, we assumed that an integrated market footprint would consist only of the ISO and PacifiCorp. We estimated the two BA's capacity needs based on peak loads and their respective existing planning reserve margins of 15% and 13%, respectively. Then, we assumed that, when integrated, both the ISO and PacifiCorp would continue to retain their current planning reserve margins to satisfy resource adequacy requirements.[13]

Table 1 shows our calculation of 2020 capacity savings for the ISO and PacifiCorp. The potential capacity savings for PacifiCorp are substantially larger than those for the ISO. This result is driven by the fact that PacifiCorp's contribution to the combined regional market peak is substantially less than the ISO's. However, PacifiCorp's capacity savings are limited by its 776 MW import capability from the ISO. In contrast, the ISO is able to achieve the full potential capacity savings of 184 MW without the need to add to the 982 MW of assumed transmission capability for imports from PacifiCorp.

Row 2 of Table 1 shows the two BA's internal (non-coincident) peaks. Multiplying this non-coincident peak with the *Median Coincidence Factor* in row 3 yields the BAs' shares of the regional market peak, shown in row 4. Potential capacity savings are estimated by multiplying the BA's reserve requirement (in row 1) by the difference between the non-coincident peak and the BA's share of regional market peak, as shown in row 5. These savings are then limited by the assumed maximum transmission import capacity shown in row 6.

Thus, we estimated the ISO and PacifiCorp's reduction in installed generating capacity needs as the lesser of (a) the potential capacity savings and (b) the transmission import capability from the other area (776 MW from ISO to PAC and 982 MW from PacifiCorp to the ISO). The MW savings achievable with the assumed transmission capability is shown in row 7, and additional MW savings associated with potential future transmission upgrades are shown in row 8.

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13 Similar to the E3 PAC Integration study, we do not alter PacifiCorp's reserve margin in the integrated market case. If we had assumed that PacifiCorp's reserve margin matched the ISO's 15% when part of the regional market, PacifiCorp's capacity savings achievable with current transmission would not change, but the savings achievable through added transmission capability would decrease by approximately 240 MW.

Table 3: Estimated Generating Capacity Cost Savings from Load Diversity in 2020
All results reported in 2016 dollars

		ISO	PacifiCorp	ISO+PAC Total
Capacity Requirement	[1]	115.0%	113.0%	
Non-Coincident Peak (MW)	[2]	47,010	13,234	60,244
Median Coincidence Factor	[3]	99.7%	92.2%	
BA's Share of Regional Market Peak (MW)	[4]	46,849	12,201	59,050
Potential Capacity Savings (MW)	[5]	184	1,168	1,352
Maximum Transmission Import Capability (MW)	[6]	982	776	
Savings w/ Current Transmission (MW)	[7]	184	776	960
Savings Requiring Transmission Upgrades (MW)	[8]	0	392	392
Avoided Cost of Capacity Savings ($/kW-yr)	[9]	$35	$0–$39	
Total Avoided Cost w/ Current Transmission ($ million/yr)	[10]	$6	$0–$30	$6–$37

Sources and Notes:
[1]: Based on PacifiCorp 2014 IRP and the ISO's published reserve margins.
[2]: Forecast 2020 Non-Coincident Peak Loads. ISO from 2015 IEPR, equal to CEC "Mid Baseline Case." PacifiCorp from 2015 LAR Peak and Energy forecast, PACE + PACW coincident peak.
[3]: Median of annual coincidence factors calculated based on 4CP of hourly load profiles from 2006 to 2014.
[4]: [2] * [3]
[5]: [1] * ([2] – [4])
[6]: Contracted import capability for the ISO and PacifiCorp.
[7]: Minimum of [5] and [6]
[8]: [5] – [7]
[9]: ISO's value reflects 2012–2016 weighted-average resource adequacy contract prices. High end of PacifiCorp range reflects capacity cost net of energy margins for two units as reported in the 2015 IRP. The low end reflects the fact that these new units are not expected to come online before 2020.
[10]: [9] * [7]

Row 9 estimates the avoided cost of capacity in 2020 for the ISO by using a 2012–2016 weighted average capacity contract price of $35/kW-year.[14] For PacifiCorp, we used a range from $0/kW-year to $39/kW-year based on the capacity cost (net of energy margins) of two new generating units in PacifiCorp's 2015 Integrated Resource Plan ("IRP"), as reported in E3's PAC Integration study.[15] Since PacifiCorp's 2015 IRP reported that the new generating units would not be needed until sometime after 2020, we estimated a low end of our range that assumes that the capacity savings would have no value in 2020. (Zero is a very conservative lower bound because load diversity would increase reliability and the higher reliability would have a non-zero

[14] This value is based on the PAC Integration study's reported average California Resource Adequacy Requirement (RAR) Contract Price for existing generation of $34.80/kW-year for 2012–2016.

[15] The E3 PAC Integration study reports an average capacity price net of energy margins of $37.50/kW-year in 2014 dollars, which we inflate to 2016 dollars at 2%.

value.) The resulting estimates of the potential savings for the combined region range from $6 million to $37 million in 2020, as shown in row 10.

F. Generating Capacity Cost Savings from Load Diversity in 2030

We applied the same approach to the 2030 analysis by utilizing each BA's reserve margins and then estimating the regional market's reserve margin based on coincidence factors. For several BAs we rely on recently-published Integrated Resource Plans (Nevada Power, PacifiCorp, Arizona Public Service, Tucson Electric Power, and Puget Sound) for the planning reserve margin requirements as the relevant metric for the individual stand-alone cases. For the remaining BAs, we used the WECC-determined planning reserve margins for the subregion where the BA is located.[16]

Because the BAs are, to some extent, taking advantage of the load diversity within their WECC subregions, we first estimated the amount of load diversity savings upon which those BAs already rely before estimating the incremental amount that they could enjoy through market integration.[17]

Table 2 at the end of this section is a summary table that includes the resulting estimates at various steps of the analysis and reports the findings. The table reports savings separately for California (*i.e.*, the CAISO, LADWP, BANC, IID, and TID balancing areas) and the Rest of Region (*i.e.*, remaining balancing areas in the U.S. WECC, except the PMAs).

We estimated the capacity savings due to load diversity in 2030 with two steps. In the first step, we estimated the full extent to which a BA can share capacity within its existing WECC subregion. We did so by comparing (1) the installed capacity needs using the WECC-determined planning reserve margins when considering the BAs' shares of subregional coincident peak loads with (2) the capacity needs required to meet reserve margins today. Row 3 of Table 2 shows the

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[16] NERC, "2015 Long-Term Reliability Assessment," December, 2015, pp. 78 – 85, Available: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf

[17] For example, Puget Sound's 2013 IRP reports a planning reserve margin of 13.5% for 2014–2015 and a capacity requirement of 6,000 MW based on peak load of 5,300 MW. The document shows that 1,600 MW of import capability is used to meet its capacity requirement and only 4,400 MW is held locally. This implies an effective *internal* reserve requirement of 4,400 MW / 5,300 MW = 83% of peak load.

average coincidence factor of BAs in California and the Rest of Region. The estimated total savings that BAs can capture within their subregions are shown in row 5 of Table 2.

Based on our review of individual BAs' IRPs, we were able to estimate the extent to which some of these savings are captured today by some of the BAs. Of the remaining incremental subregional savings, some of them are likely limited by the simultaneous transmission import constraints (conservatively estimated) on the existing grid. For example, the remaining subregional savings in the Rest of Region are limited largely due to limits on import capability into Portland General Electric (PGE) and Puget Sound. The within-subregion savings in California are all attributable to LADWP, TID, and IID joining the assumed regional market. The ISO itself does not benefit from subregional diversity, because its internal peak load occurs in the same hour as the coincident peak of the California subregion.[18]

To estimate the potential incremental benefits from load diversity within each subregion, we subtract from row 5 the amount that BAs already capture today (shown in row 6). The difference between Rows 5 and 6 is then compared to a conservative estimate of simultaneous transmission import capabilities (as explained below) for each BA from within its subregion, after accounting for the import capability used to achieve the savings in row 6. The estimated incremental subregional load-diversity savings that can be captured without additional transmission are shown in row 7.

In the second step, we use the same approach to estimate the potential savings that could be achieved by sharing capacity across subregions in the entire regional market's footprint (U.S. portion of WECC without the PMAs). As before, we estimate the capacity savings after accounting for the WECC-determined planning reserve margins and the subregional shares of the coincident peak load of the assumed regional market's footprint. The resulting potential capacity savings of integrating WECC subregions with the market's footprint are then shown in row 11.

As is clear from comparing rows 5 and 11, the potential savings from integrating portions of WECC subregions into the larger regional market footprint are larger than the estimated subregional savings, reflecting that a substantial amount of load diversity across the subregions

[18] BANC does not contribute to the total capacity savings in California because it is import-constrained.

can be captured by the Regional Market. These region-wide savings are generally less constrained by transmission limitations than the within-subregion savings.

As discussed above, we observe that some BAs are taking advantage of load diversity. They do so by assuming that spot-market imports from neighboring BAs can be used to avoid loss of load events in their area. This resource adequacy benefit of imports is either reflected in a reduction in the BA's planning reserve margin (as is the case for PacifiCorp)[19] or the explicit assumption that a portion of the planning reserve requirements can be met through uncommitted transmission import capability rather than through BA-internal resources (as is the case for Puget Sound).[20] In the case of Puget Sound, we calculated total subregional load diversity benefits equal to approximately 35% of its internal peak load, but estimated (from the company's IRP filing) that most of these load diversity savings—but for 4% of its internal peak load—are already realized today. In other words, the extent to which BAs are taking advantage of load diversity benefits within their region is reflected in BA-internal planning reserve margins (that need to be satisfied through BA-internal resources), which are lower compared to the WECC-determined planning reserve margins for the entire subregion. Because we were not able to gather the necessary information from all BAs but recognized that they will likely be able to take advantage of load diversity savings today, we used the WECC-determined planning reserve margins for those BAs but, based on the Puget Sound example, we limited total load-diversity savings to a maximum of 4% of each of these BA's non-coincident peak load.

To estimate the extent to which transmission constraints may limit the realization of load-diversity benefits, we identified the available intertie capabilities between balancing areas using

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[19] PacifiCorp's planning reserve margin (which needs to be satisfied through committed BA-internal resources) of 13% is below the WECC subregional reserve margin of 15.4% because of the load diversity and PacifiCorp's interties with neighboring balancing areas. PacifiCorp, "2015 Integrated Resource Plan Volume 2 – Appendices," March 2015. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

[20] Puget Sound's IRP shows that it allows uncommitted imports to satisfy 1,600 MW of the total resources needed to achieve its 13.5% planning reserve margin. Puget Sound, "2013 Integrated Resource Plan Chapters 1–7," May 2013. Available at: https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf. This IRP specification can be translated to Puget having to meet only 83% of its peak load through BA-internal resources.

the transmission capability data published by WECC's Loads and Resources subcommittee.[21] The model provides summer and winter transfer limits between 19 zones in the WECC. We used the lower of the two seasonal limits, which usually occurs in the summer. Figure 1 shows the summer transfer limits between zones.

To derive a conservative estimate of the maximum import capability into each BA for estimating available load diversity benefits, we assumed that (1) the available simultaneous import capability would be no larger than the capability of the largest intertie with neighboring BAs and (2) any capacity savings already achieved would be using up some of the import capabilities on the existing lines.[22]

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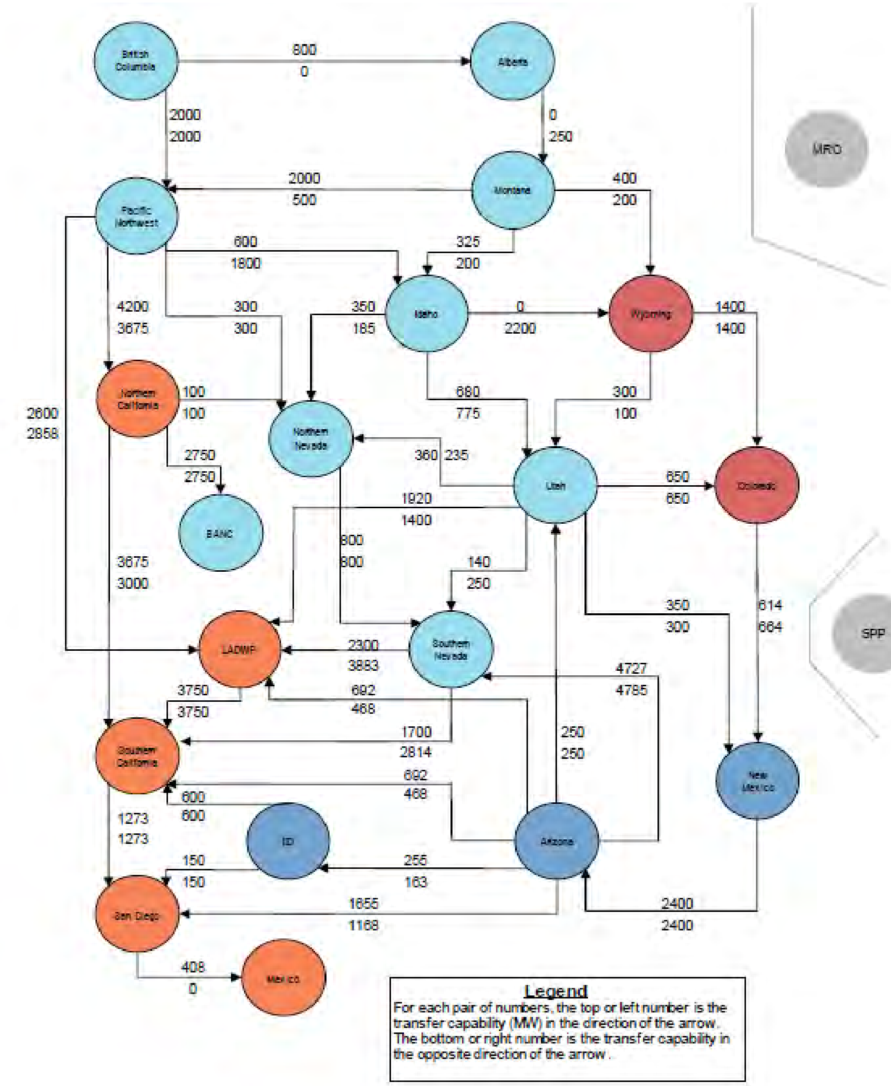
21 WECC Staff, "Loads and Resources Methods and Assumptions," November 2015, Table 4, Available at: https://www.wecc.biz/ReliabilityAssessment

22 For several BAs in the Northwest (Avista Corp, Portland General Electric, PUD No 1 of Chelan County, PUD No 1 of Douglas County, Puget Sound Energy Inc., Seattle City Light, Tacoma Power), our estimated within-subregion import capability is *less* than the capacity savings achieved. Because we do not have specific data on transfer capabilities within the Northwest, our estimated import capabilities for these BAs conservatively assume that imports can come only from outside the Northwest. In reality, however, there is substantial transmission capacity in this region and the BAs are likely making use of it. We confirmed this for Puget Sound using its IRP. We assumed that the other BAs could similarly take advantage of transmission within the Northwest.

Figure 2: LAR Zonal Model Summer Transfer Limits



Sources and Notes

WECC Staff, "Loads and Resources Methods and Assumptions," November 2015, Table 4, Available at: https://www.wecc.biz/ReliabilityAssessment.Zone colors correspond to subregions: Orange – California, Light blue – Northwest, Dark blue – Southwest, Red – Rocky Mountain

Finally, we estimated that the avoided cost of capacity savings in 2030 would be $75/kW-yr in California and $100/kW-yr in the rest of the region. The value for California assumes that no new generation will be needed prior to 2030, but that the state will be approaching resource balance and the value of capacity will be increasing. Under such conditions, we would expect the value of capacity to converge to the cost of new entry net of energy and ancillary service margins (*i.e.*, the *net* cost of new entry). The net cost of new entry for a combined-cycle natural gas unit in California has been estimated to be in excess of $150/kW-year.[23] However, we made the conservative assumption that the value of capacity in 2030 is only $75/kW-year based on the conservative assumption of continued (though less severe) excess supply conditions.[24] If additional generating capacity would be needed by 2030 (e.g., due to additional retirements of economically-challenged existing plants), the estimated resource adequacy value of regional load diversity would be double out baseline estimate.

Outside of California, we estimated that the avoided cost of capacity savings in 2030 is $100/kW-year, reflecting the net cost of new entry and the likelihood of new generation needs. Row 17 of Table 2 shows that the net capacity cost savings due to load diversity is $120 million for California and over $260 million for the rest of the region in 2030.

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23 See, for example: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf

24 This assumes that, other than plants with once-through cooling and Diablo Canyon, no other major existing California generating plant would be retired between now and 2030. Based on feedback by the owners of these generating plants, this is a very (and perhaps unrealistically) conservative assumption because such additional retirements are very likely given the poor existing (and deteriorating future) market conditions faced by these plants.

Table 4: Estimated Generating Capacity Cost Savings from Load Diversity in 2030
All results reported in 2016 dollars

		California	Rest of Region
Capacity Requirement	[1]	115.0-116.1%	75-116.1%
Sum of BA Non-Coincident Peaks (MW)	[2]	57,188	85,302
BA Coincidence Factor (Coincidence with Subregion peak)	[3]	99.2%	94.2%
Sum of BA Peak Loads Coincident with Subregion Peak (MW)	[4]	56,747	80,364
Potential Savings: Sharing Within Subregions (MW)	[5]	508	5,703
Savings Already Captured (Estimated) (MW)	[6]	0	4,481
Incremental Savings w/ Current Transmission: Sharing Within Subregions (MW)	[7]	363	604
Savings Requiring Transmission Upgrades (MW)	[8]	145	618
Effective Coincidence Factor (Coincident **with WECC-PMAs peak)**	[9]	98.1%	96.3%
Estimated Load During WECC Peak (MW)	[10]	55,676	77,415
Potential Savings: Sharing Across Subregions (MW)	[11]	1,231	3,385
Incremental Savings w/ Current Transmission: Sharing Across Subregions (MW)	[12]	1,231	2,060
Savings Requiring Transmission Upgrades (MW)	[13]	0	1,324
Total Savings Requiring Transmission Upgrades (=[8] + [13]) (MW)	[14]	145	1,942
Total Savings w/ Current Transmission (=[7] + [12]) (MW)	[15]	1,594	2,665
Avoided Cost of Capacity Savings ($/kW-yr)	[16]	$75	$100
Total Avoided Cost w/ Current Transmission ($ million/yr)	**[17]**	**$120**	**$266**

Sources and Notes:

[1]: Capacity requirement based on WECC-determined reserve margin levels as reported in 2015 NERC LTRA

[2]: Sum of forecasted BA Non-Coincident Peak Loads in 2030

[3]: Median of 2006-2014 coincidence factors between BA and subregion peaks. Table shows average across BAs in California and Rest of Region, weighted by non-coincident peak loads..

[4]: [2] * [3]

[5]: [1] * ([2] – [4])

[6]: Capacity savings already achieved by BAs based on internal reserve margins

[7]: Savings achievable with current transmission into each BA

[8]: Savings requiring additional transmission based on within-subregion transmission limits in WECC LAR zonal model.

[9]: Median of coincidence factors between subregion and footprint-wide peaks, estimated from hourly BA load data from 2006 to 2014.

[10]: [4] *[9]

[11]: [1] * ([4] – [10]). The ISO savings based on share of Subregion peak load

[12]: Savings achievable with current transmission into each subregion

[13]: Savings requiring additional transmission based on across-subregion transmission limits in WECC LAR zonal model.

[14]: [8] + [13]

[15]: [7] + [12]

[16]: Average avoided cost of new entry for each subregion reflecting $75/kW-yr for California Balancing Authorities and $100/kW-yr for non-California Balancing Authorities.

[17]: [15] * [16]

G. SENSITIVITY: GENERATING CAPACITY COST SAVINGS FROM LOAD DIVERSITY IN 2020 WITH AN EXPANDED REGIONAL ISO FOOTPRINT

Our baseline assumes that in 2020, the regional market will be limited to the ISO and PacifiCorp. However, we evaluated capacity savings for a sensitivity case where all of the U.S. WECC (except the PMAs) participates. In this 2020 Regional sensitivity case, we applied the same methodology as in our 2030 analysis, using historical coincidence factors to estimate the savings associated with load diversity. As with our 2030 analysis, we estimated capacity savings in this sensitivity case in two steps: savings from capacity sharing *within* WECC subregions and savings from capacity savings *between* WECC subregions. We accounted for capacity savings achieved by utilities and for transmission limitations in the same manner as in our 2030 analysis. For the purposes of the sensitivity, we used a lower avoided cost of capacity savings of $35/kW-year, reflecting the 2012–2016 weighted average resource adequacy contract price in California and the upper end of the zero to $37/kW-year range that was used for PacifiCorp.

As expected, the 2020 regional sensitivity results show that a larger regional footprint in 2020 provides additional benefits for California, but not as much as could be achieved in 2030. Savings are higher compared to the 2020 baseline scenario for two reasons: 1) adding LADWP, BANC, TIDC, and IID to the market region increases the participating load in California and 2) including most of the WECC in the regional market increases the potential for load diversity. Savings are lower compared to the 2030 baseline due to two offsetting factors. First, the MW savings are higher in the 2020 regional sensitivity because 2020 load is higher than 2030 load due to high energy efficiency targets, which result in negative projected load growth. However, the higher MW savings are offset by lower avoided costs assumed in 2020 ($35/kW-year in 2020 vs. the $75/kW-year baseline in 2030) in California. This yields estimated 2020 savings of $58 million/year for California and $84 million/year for the rest of the region.

Table 5: Estimated Generating Capacity Cost Savings from Load Diversity in the 2020 Regional Sensitivity

All Results Reported in 2016 dollars

		California	Rest of Region
Capacity Requirement	[1]	115-116.1%	75-116.1%
Sum of BA Non-Coincident Peaks (MW)	[2]	59,688	75,829
BA Coincidence Factor (Coincidence with subregion peak)	[3]	99.3%	94.0%
Sum of BA Peak Loads Coincident with Subregion Peak (MW)	[4]	59,262	71,295
Potential Savings: Sharing Within Subregions (MW)	[5]	491	5,236
Savings Already Captured (Estimated) (MW)	[6]	–	4,136
Incremental Savings w/ Current Transmission: Sharing Within Subregions (MW)	[7]	353	533
Savings Requiring Transmission Upgrades (MW)	[8]	138	567
Effective Coincidence Factor (Coincident with WECC-PMAs peak)	[9]	98.1%	99.8%
Estimated Load During WECC Peak (MW)	[10]	58,129	68,689
Potential Savings: Sharing Across Subregions (MW)	[11]	1,304	2,991
Incremental Savings w/ Current Transmission: Sharing Across Subregions (MW)	[12]	1,304	1,856
Savings Requiring Transmission Upgrades (MW)	[13]	–	1,135
Total Savings Requiring Transmission Upgrades (=[8] + [13]) (MW)	[14]	138	1,702
Total Savings w/Current Transmission (=[7] + [12]) (MW)	[15]	1,657	2,388
Avoided Cost of Capacity Savings ($/kW-yr)	[16]	$35	$35
Total Avoided Cost w/Current Transmission ($ million/yr)	[17]	$58	$84

Sources and Notes:

[1]: Capacity requirement based on WECC-determined reserve margin levels as reported in 2015 NERC LTRA

[2]: Sum of forecast BA Non-Coincident Peak Loads in 2020

[3]: Median of 2006-2014 coincidence factors between BA and subregion peaks. Table shows average across BAs in California and Rest of Region, weighted by non-coincident peak loads. It is slightly different than the 2030 value because non-coincident peak loads are slightly different in 2020.

[4]: [2] * [3]

[5]: [1] * ([2] – [4])

[6]: Capacity savings already achieved by BAs based on internal reserve margins

[7]: Savings achievable with current transmission into each BA

[8]: Savings requiring additional transmission based on within-subregion transmission limits in WECC LAR zonal model.

[9]: Median of coincidence factors between subregion and footprint-wide peaks, estimated from hourly BA load data from 2006 to 2014.

[10]: [4] *[9]

[11]: [1] * ([4] – [10]). The ISO savings based on share of Subregion peak load

[12]: Savings achievable with current transmission into each subregion

[13]: Savings requiring additional transmission based on across-subregion transmission limits in WECC LAR zonal model.

[14]: [8] + [13]

[15]: [7] + [12]

[16]: Assumed avoided cost of $35/kW-yr for California and Rest of Region in the 2020 Regional scenario

[17]: [15] * [16]

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Senate Bill 350 Study

Volume VII: Ratepayer Impact Analysis

PREPARED FOR

California ISO

PREPARED BY

THE Brattle GROUP

Energy+Environmental Economics

July 8, 2016

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

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Volume VII. Ratepayer Impact Analysis

A. Introduction and Summary

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate or regional entity ("Regional ISO"). SB 350, in part, specifically requires an evaluation of "overall benefits to ratepayers." The Brattle Group ("Brattle") and Energy and Environmental Economics, Inc. ("E3") have been engaged to study these ratepayer impacts. This report is Volume VII of XII of our study in response to SB 350's legislative requirements.

Considering both the language of SB 350, and stakeholder comments and feedback, we interpret "overall benefits to ratepayers" to mean impacts on California electricity customer costs. Our primary metric for these impacts are estimated annual dollar savings to California ratepayers for our study years, baseline regional market scenarios, and additional sensitivities.[1] The baseline scenarios and sensitivities analyzed are summarized in Volume III of this report.

We find that California's ratepayers would save $55 million/year (0.1% of retail rates) in 2020 under the limited CAISO+PAC regional market scenario. The estimated annual savings for the expanded regional footprint (U.S. WECC without PMAs) increase to $1–$1.5 billion/year (2–3% of average customer retail rates) by 2030 for our baseline scenarios, depending on the procurement of renewable resources to meet the state's 50% RPS.

These savings have four primary components: (1) a reduction in renewable investment costs, represented as a levelized annual cost of procuring enough renewables and supporting system resources to meet the state's 50% Renewable Portfolio Standard ("50% RPS") by 2030; (2) a reduction in California's net costs associated with the California load-serving entities' production, purchases, and sales of wholesale power; (3) a reduction in generation capacity costs

[1] Measured in 2016 dollars. The study team analyzed the benefits on a total dollar and state-wide average retail rate basis for California; we did not evaluate impacts at the retail ratepayer class or for each of the utilities because every utility's rate classifications and cost allocations are different.

to meet planning reserve requirements, represented as a levelized annual cost of procuring capacity; and (4) a reduction in annual ISO operating costs, represented as an estimate of the ISO's Grid Management Charge that would be allocated to California ratepayers on a load-share basis. The detailed analyses of each of the components (1), (2), and (3) are discussed in Volumes IV, V, and VI of this report, respectively. Detail on the estimated reduction in Grid Management Charges is discussed in Section F of this volume. The results from each of these four categories of analyses are inputs to the ratepayer impact analysis discussed here.

For the ratepayer impact analysis we use a spreadsheet model to estimate the total annual retail revenue requirement needed to serve California's electric loads, including the four key components of ratepayer impact as listed above. By calculating the total revenue requirement (i.e., instead of simply adding up the four components) we are able to provide results that can be expressed both in absolute terms ($ and ¢/kWh) and in percentage terms (% change in revenue requirements and average customer costs). We estimate that 82% of the total revenue requirement is fixed and, thus, does not change across the scenarios modeled in this study.

B. COMPONENTS OF RATEPAYER IMPACT ANALYSIS

The four key component of this state-wide California ratepayer impact analysis are:

1. **Annual investment and other fixed costs related to expanding California's portfolio of renewable resources**, based on RESOLVE model results, and including costs of storage and transmission needed to facilitate these renewable resources. The RESOLVE model is used to quantify the procurement cost of meeting California's RPS targets in the CAISO balancing area in different scenarios representing different levels of regionalization. Results for the non-CAISO entities in California are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario. With regionalization, we find that renewables would be better integrated into the regional system and California's investments would be more efficient. In other words, regionalization would allow California to build less renewables capacity to meet its 50% RPS. Additionally, regional operations and markets would give California better access to lower-cost out-of-state resources in wind- or solar-rich areas of the west. The assumptions and methodology to the renewable energy portfolio analysis are described in Volume IV of the SB 350 study.

2. **California's net costs associated with production, purchases, and sales of wholesale power**, based on production cost simulation results, and estimated consistent with CAISO's Transmission Economic Assessment Methodology (TEAM). For California ratepayers, the TEAM benefits calculation consists of:

   (+) Generator costs (fuel, start-up, variable O&M, GHG) for generation owned or contracted by the California load-serving utilities;

   (+) Costs of market purchases by the California load-serving utilities from merchant generators in California and imports from neighboring regions; and

   (–) Revenues form market sales and exports by the California load-serving utilities.

   The assumptions and methodology for the production cost simulations and TEAM benefits calculation are described in Volume V of this report.

3. **California's capacity cost savings from regional load diversity**, based on historical hourly load patterns, and estimated based on the reduction in generating capacity needed to meet the coincident peak load of balancing areas ("BAs") than to meet the peak load of each BA separately. For this study, we analyze the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity needs due to market integration. This analysis measures "load diversity" as the degree to which individual BA peak loads occur at different times, which leads to a coincident peak load for the combined footprint that is lower than the sum of the individual BA-internal peak loads. This reduction in coincident peak load is then used to estimate the generation investment cost savings offered by a regional market. The assumptions and methodology to the load diversity analysis are described in Volume VI of this report.

4. **Reduction in Grid Management Charges ("GMC") to California ratepayers**, based on the ISO's revenue requirement, and driven by the lower rates estimated for system operations and market services. The ISO's revenue requirement consists of the operation and maintenance cost, which is the substantially component, debt service recovery including 25% reserves, cash funded capital less operating cost reserves and other revenue. We relied on CAISO's estimate of future GMC charges with and without regionalization. These calculations are described in Section F of this Volume VII.

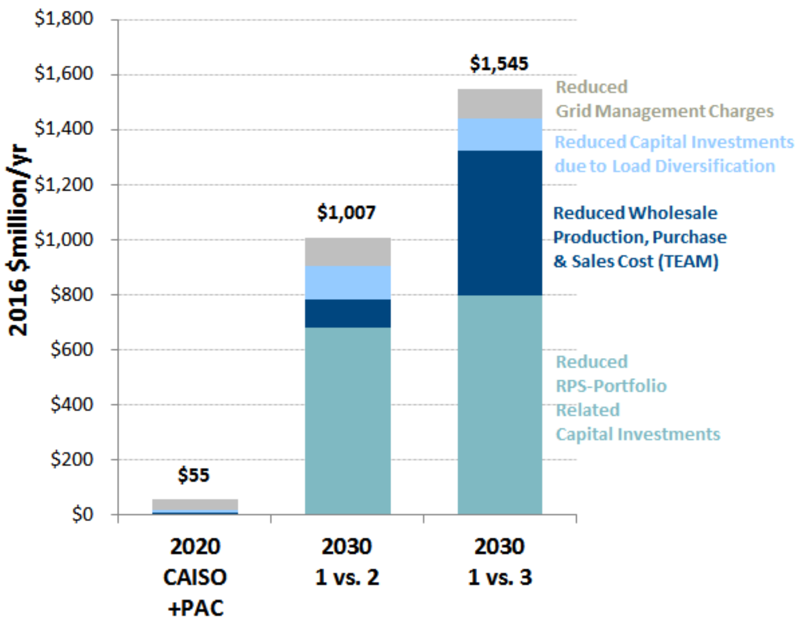
The expansion of the CAISO into a larger regional market would also affect the allocation of existing transmission costs and new transmission investments, both of which will depend on how those allocations are negotiated as a part of the regional market design. For the purpose of this study, we have assumed that: (1) existing transmission costs for each area will be recovered from each area's local load; and (2) the cost of additional transmission needed to achieve public policy goals will be allocated to the areas with those public policy goals. Currently, California customers pay for existing out-of-state transmission that is needed to support the prevailing power imports, and those transmission costs may be combined with power purchase costs. Such transmission costs associated with imports from neighboring areas, currently paid for by California, are offset in part by "wheeling" revenue associated with power exports to neighboring areas. In a regional market, California would no longer need to pay for transmission associated with imports from elsewhere in the regional market, but would also no longer collect revenues associated with exports. Our analysis assumes that the benefits of reducing transmission wheeling costs associated with imports would be fully offset by the payments for the existing regional transmission facilities that exporters used to pay.

With respect to imports of additional renewable resources developed to meet the 50% RPS mandate (and as explained further in Volume IV), we assumed that (and have included in the estimated renewable procurement costs): (1) any costs associated with new transmission needed to integrate these new resources would be allocated to California loads (particularly relevant in Regional 3 with increased reliance on out-of-state resources); and (2) California loads would benefit from a regional market's de-pancaked regional transmission charges to the extent that the additional renewable resources can be delivered over the existing transmission grid (without additional transmission upgrades). Renewable projects developed beyond RPS needs are assumed to include in their contract prices with voluntary buyers any transmission interconnection-related costs (to reach local transmission hubs) and that those projects may face greater curtailment risks and congestion costs (both reflected in our market simulations) to the extent the local and regional transmission grid cannot fully accommodate their output.

C. Ratepayer Impacts for Baseline Scenarios

The California ratepayer impact analysis of an expanded regional market shows estimated annual savings of $55 million/year (0.1% of retail rates) in 2020 for the CAISO+PAC regional market scenario. The estimated annual savings for the expanded regional footprint (U.S. WECC without PMAs) increase to $1–$1.5 billion/year (2–3% of retail rates) for our 2030 baseline scenarios, depending on the procurement of renewable resources to meet the state's 50% RPS. These results are summarized in Figure 1.

Figure 1: Estimated Annual California Ratepayer Net Benefits from an Expanded Regional ISO-Operated Market



As shown in Figure 1 (the bottom portion of the 2030 bars), approximately $680–$800 million of the estimated savings in 2030 are associated with the reduction in the **annual capital investment costs related to the renewable procurement** necessary to meet California's 50% RPS. The range of the RPS-portfolio-related annualized investment costs savings depends on California's willingness and ability to rely on lower-cost renewables from outside of California (Regional 2 vs. 3) and the costs associated with building the transmission needed to deliver the resources to the expanded regional market. Under the 2030 Current Practice 1, the annual costs of procuring the necessary renewable resources increase as renewable curtailments increase and the need to build more renewables to meet the RPS requirements increases with it. The costs of procuring renewable resources decrease if California were able to export more of the oversupply under the current practices bilateral trading model (as estimated in sensitivity results for a high-flexibility Current Practice 1B, as discussed further below). Further details on underlying modeling approach, key input assumptions, sensitivity analyses, and results are provided in Volume IV of this report.

As shown in the dark blue slices of the bars shown in Figure 1, we estimated that the expansion of the regional market will create 2030 annual savings of $104–$523 million/year associated with California's **net costs of production, purchases, and sales** of wholesale power. This portion of the 2030 California ratepayer savings comes from: (a) lower production costs of owned and contracted generation to meet load; (b) reduced purchase costs when load exceeds owned and contracted generation (higher in Regional 2 with more REC-only purchases); and (c) higher revenues when selling into the wholesale market during hours with excess owned and contracted generation (we conservatively assume power is sold at no less than $0/MWh in these baseline estimates). The production and purchase/sale cost impacts capture the increased efficiency of trades due to de-pancaking of transmission charges, reduced operating reserves, regionally optimized unit commitment, and economically-optimized dispatch of generation in the day-ahead market, subject to the available transmission capabilities. Further details on production cost simulations and the calculation of California costs associated with production, purchases, and sales under the TEAM approach are provided in Volume V of this report.

As shown by the sky blue slide of the bars in Figure 1, the integration of existing balancing areas into a broader ISO-operated regional market yields savings related to **load diversity**, allowing for the reduction of investments in resources necessary to meet system-wide and local resource adequacy requirements. These resource adequacy-related benefits of load diversity can be assessed from either a reliability perspective (*e.g.*, by holding generation investments constant and analyzing the benefit of improved reliability) or from an investment-cost perspective (*e.g.*, by holding the level of reliability constant and analyzing the reduction in generation investment needs). For this study, we estimated the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity costs due to larger regional market. Because each of the individual balancing area within the region experiences peak loads at different times, the coincident peak load for the combined region is lower than the sum of the individual areas' internal peak loads. Accordingly, the expanded regional market is estimated to reduce California's resource adequacy capacity needs by 184 MW in the 2020 CAISO+PAC scenario with annual capacity cost savings of $6 million/year, and by 1,594 MW in 2030 under the expanded regional footprint (U.S. WECC without PMAs), with annual savings of $120 million/year. Further details on load diversity analyses, including data used, key assumptions, and findings are discussed in Volume VI of this report.

The top grey slice of the bar shown in Figure 1 is the estimated California ratepayer benefits associated with the **cost of ISO operations**. The total costs of grid management would increase with the expansion of the regional market, but these costs would be paid by a much larger group of customers within the larger region, resulting in reductions of the GMC rates paid by California and other regional market customers. The expansion of the regional market is estimated to reduce the average GMC rates by 19% in 2020 under the CAISO+PAC versus the 2020 Current

Practice scenario, creating $39 million of annual savings for California ratepayers. These savings increase to 39% in 2030 under the expanded regional footprint (U.S. WECC without PMAs) with California ratepayers' savings increasing to $103 million per year. Further details on the calculation of Grid Management Charges and the associated California impact of a regional ISO-operated market are included in Section E of Volume VII of this report.

Impacts on Total Revenue Requirement, Average Customer Costs, and Retail Rates

The baseline total retail revenue requirement is based on the U.S. Energy Information Administration's ("EIA") 2015 revenue requirement for the state of California, including investor-owned utilities and publicly-owned utilities.[2] We assume that 82% of the 2015 revenue requirement is fixed and thus does not change across the scenarios modeled in this study (i.e., only the remaining 18% is a variable cost covered by TEAM variable procurement cost and an RPS-portfolio-related variable capital investment cost). These fixed costs of serving California retail load that do not vary across the modeled scenarios consist of the costs associated with existing transmission, distribution, generation and renewables, DSM programs, and other fees. These fixed retail costs are assumed to increase at a 1% real escalation rate.

As shown in Figure 2, the total annual retail revenue requirement associated with serving California ratepayers is then calculated by adding the results from the four components of ratepayer impact calculations presented above to the estimated "base" of fixed retail costs. Average retail rates are then calculated by dividing the total annual retail revenue requirements by the projected total kWh of retail sales within California.[3] As shown in Figure 2, average retail rates are projected to be 19.8 cents/kWh in 2030 for the Current Practices 1 scenario. In the regional market scenario, these rates decline to 19.4 cents/kWh for the Regional 2 scenario and to 19.2 cents/kWh in in the Regional 3 scenario. This means the 2030 impacts from an expanded regional ISO market are estimated to decrease average customer retail rates in California by at least 0.4–0.6 ¢/kWh or by 2.0% to 3.1%.

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2 Available here: http://www.eia.gov/electricity/data/eia826/xls/sales_revenue.xls

3 Total state-wide kWh of retail sales are based on 2015 EIA data, reconciled with 2015 data and forecasts from the California Energy Commissions, consistent with the assumptions used in production cost simulations.

Figure 2: Summary of Impacts on California Customer Costs and Retail Rates

		2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Base Costs	($MM)	$35,564	$35,564	$39,285	$39,285	$39,285
Incremental RPS-Portfolio Related Capital Investment	($MM)	$0	$0	$3,292	$2,612	$2,492
Production, Purchase & Sales Cost (TEAM)	($MM)	$7,752	$7,742	$8,066	$7,962	$7,544
Load Diversification Benefits	($MM)	$0	($6)	$0	($120)	($120)
Grid Management Charges Savings	($MM)	$0	($39)	$0	($103)	($103)
Cost of Electricity Supply to California Customers	**($MM)**	**$43,316**	**$43,262**	**$50,643**	**$49,636**	**$49,098**
Impact of Regionalization	($MM)		($55)		($1,007)	($1,545)
	(%)		(0.1%)		(2.0%)	(3.1%)
Total Sales	(GWh)	260,028	260,028	256,404	256,404	256,404
Average Cost to California Customers	**(cent/kWh)**	**16.7**	**16.6**	**19.8**	**19.4**	**19.1**
Impact of Regionalization	(cent/kWh)		(0.0)		(0.4)	(0.6)
	(%)		(0.1%)		(2.0%)	(3.1%)

Our ratepayer impact analysis reflects a number of conservatisms for each of the four impact components analyzed. The conservative nature of these analyses is discussed in more detail in Volumes I, IV, V and VI. For example, as discussed in Volume V, the production cost models do not capture benefits under strained system conditions; instead they reflect only "normal" weather, hydroelectric conditions, and loads for the entire WECC area. The production cost models also do not reflect other challenging system conditions, such as transmission outages, fuel supply disruptions (e.g., Aliso Canyon impacts), or real-time uncertainties. The model also conservatively assumes "perfect" market behavior such as competitive bidding, ISO-like optimized commitment and dispatch under current practices within each balancing area, perfectly efficient bilateral trading (other than what is reflected in hurdle rates), and optimal use of the existing grid by bilateral markets. Similarly, as discussed in Volume VI, the load diversity analysis only captures a portion of reliability-related benefits. It does not monetize the reliability-related benefits of load diversity in an integrated market; it does not consider the additional benefits that would accrue given the anticipated retirement of substantial existing generation in California; and it uses an ex-ante methodology that has been determined after-the-fact to under-estimated benefits. Many of these conservatisms are typical to market integration studies. This is discussed in more detail in our review of other market integration studies (Volume XII), also summarizes the experience with regional market integration across the country and in Europe.

These studies and experiences point to a number of other modeling conservatisms. In particular, our analysis does not include the monetary value of a wide range of reliability-related benefits related to improvements in regional market operation, compliance, and planning—including improvements in price signals, congestion management, unscheduled flow management, regional unit commitment, system monitoring and visualization, backup capabilities, operator training, performance monitoring, procedure updates standards development, NERC compliance, regional planning, fuel diversity, and long-term investment signals. Volume XI describes in more detail how a regional ISO-operated market offers benefits in these reliability and renewable integration areas.

D. Sensitivity Analyses of Ratepayer Impacts

In addition to the baseline scenarios discussed above, we analyzed ratepayer impacts under a range of alternative assumptions to understand the implications of some of the key drivers.[4] These ratepayer impact sensitivity analyses and associate results include the following.

- **Renewable Investment Cost** sensitivities, as discussed in Volume IV of the SB 350 study, reflect renewable procurement cost savings (one of the key elements of ratepayer impacts) ranging from \$391–1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings.
- The **"2020 Regional ISO"** sensitivity shows total annual California ratepayer benefits would be \$258 million/year under the expanded regional footprint (U.S. WECC without PMAs). This is significantly higher than the \$55 million/year estimated for the CAISO+PAC scenario because of the larger regional footprint, but remains well below the 2030 benefits due to the more limited benefits associated with the procurement and integration of renewable resources (since most of the renewables to meet 33% RPS in 2020 are already under contract and balancing 33% renewable generation is less challenging than balancing 50%).
- The **"2030 Current Practice 1B"** sensitivity evaluates regional market benefits assuming higher flexibility in bilateral markets. This sensitivity increases CAISO net bilateral export capability from 2,000 MW to 8,000 MW for the Current Practice case. The results

4 The full range of sensitivities analyzed is discussed in Volume III of this report.

show that even if California's future oversupply conditions could be managed more flexibly bilaterally without a regional market (as simulated in the Current Practice 1B sensitivity), the 2030 total annual ratepayer benefits of a regional market would still be a very significant, ranging from $767 million to $1.4 billion/year, depending on the scenario (Regional 2 vs. Regional 3) and price floor sensitivity (zero and negative $40/MWh) considered.

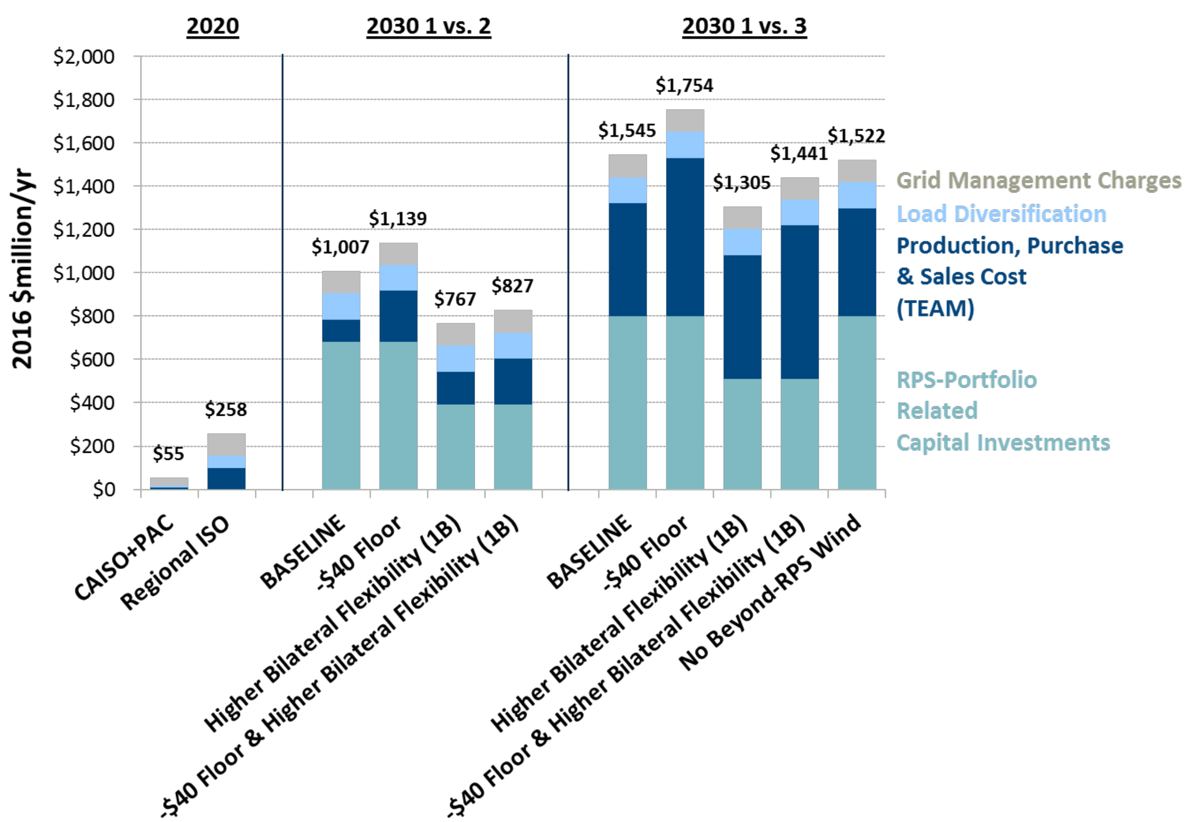
- **"Low Willingness to Buy in Bilateral Market"** sensitivity captures the impact of negative energy prices during oversupply and renewable curtailment conditions. The baseline simulations assume power is sold at no less than $0/MWh suggesting that California would give power away for free. Accordingly, sales do not impose any additional costs on California ratepayers. On the other hand, at negative prices—consistent with the recent experience in CAISO during periods with high solar generation,[5] at Mid-C during high hydro and low load periods, and in other markets (such as ERCOT, MISO, and SPP) that have been experiencing renewable generation oversupply conditions—California would have to pay counterparties to take power during oversupply conditions. The sensitivity results show that a negative $40/MWh price experienced during oversupply and renewable curtailment periods would increase the annual ratepayer benefits of regional market operations by $133–$209 million/year.

E. Comparison of Ratepayer Impacts for Baseline Scenarios and Sensitivities

Figure 3 shows overall ratepayer impacts, including the four components previously described, for all 2020 and 2030 scenarios and sensitivities that were analyzed for both the renewable procurement related capital investments and California's production, purchase, and sales costs.

[5] Negative prices are already being experienced in the CAISO footprint. For example, 7% of all 5-minute real-time pricing intervals have experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation and relatively low loads. Although some prices ranged between negative $30/MWh and negative $150/MWh, in most of the periods, the negative prices remained above negative $30/MWh. (See CAISO Internal Market Monitor "Q1 2016 Report on Market Issues and Performance.")

Figure 3: Summary of California Ratepayer Benefits All Scenarios and Sensitivities



In 2020, an expanded Regional ISO footprint would yield higher benefits to California ratepayers compared to a regional market limited to CAISO+PAC only. For 2030, our baseline Regional 2 scenario results in annual ratepayer benefits of $1,007 million/year compared to the Current Practice 1 scenario, with a range from $767 million/year (for the Higher Bilateral Flexibility 1B sensitivity and a zero dollar price floor) to a high or $1,139 million/ year (for the Current Practice 1 scenario and a negative $40/MWh price floor). Our 2030 baseline Regional 3 scenario results in annual ratepayer benefits of $1,545 million/year relative to the baseline Current Practice 1 scenario, with a range from $1,305 million/year (for the Higher Bilateral Flexibility 1B sensitivity and a zero dollar price floor) to a high of $1,754 million/year (for the Current Practice 1 scenario and a negative $40/MWh price floor).

These scenarios and sensitivities are discussed in more detail throughout this SB 350 study. Volume 1 of this study discusses for how these scenarios and sensitivities affect our overall findings and conclusions; Volume III summarizes the scenarios and sensitivities analyzed; and Volumes IV, V, and VI document more detailed assumptions and analytical approaches used to analyze renewable procurement cost savings, power production, purchase, and sales costs benefits; and load diversity benefits.

F. IMPACTS ON THE GRID MANAGEMENT CHARGE

The ISO's Grid Management Charge is the mechanism used to recover the ISO's annual revenue requirement from ISO customers. The revenue requirement consists of the operation and maintenance cost, which is the substantially component, debt service recovery including 25% reserves, cash funded capital less operating cost reserves and other revenue. The 2016 budget provides for a revenue requirement of $195.3 million which is 18% lower than the peak in 2003. Since 2007, the revenue requirement has averaged an annual increase of only 0.3%. The ISO has absorbed several major initiatives during this time with no material impact to the revenue requirement, which included launching the new market, constructing its secure primary location and implementing a regional Energy Imbalance Market.

Other Costs and Revenues

Other costs and revenues for 2016 is budgeted at $10.8 million, $1.4 million higher than 2015 primarily due to fees from the new EIM members. EIM administrative charges of 19 cents per MW of load and generation are projected to be $2.5 million in 2016, which is an increase of $900,000 over 2015. Intermittent resource forecasting fees of 10 cents per MW of generation are budgeted at $2.1 million, the same amount as 2015. The fees offset the forecasting costs for each resource incurred by the ISO that is included in O&M. Fees for completing studies of large generator interconnection projects requests increased $400,000 from 2015 to $1.8 million in 2016. The increase reflects the volume of work estimated for 2016. A small increase in other miscellaneous fees is budgeted to be $100,000 over 2015. The California-Oregon intertie path operator fees and interest earnings are anticipated to remain at the same levels as 2015. The details of this category are shown in Figure 3.

Figure 4: Other Costs and Revenues in the ISO's Grid Management Charge

Other Costs and Revenues ($ in millions)	2016 Budget	2015 Budget	Change
Intermittent Resource (wind and solar) Forecasting Fees	$2.1	$2.1	$ -
California-Oregon Intertie Path Operator Fees	2.0	2.0	-
Interest Earnings	2.0	2.0	-
Large Generation Interconnection Fees	1.8	1.4	0.4
Energy Imbalance Market Administrative Charges	2.5	1.6	0.9
Scheduling Coordinator Application and Other Fees	0.4	0.3	0.1
Total	**$10.8**	**$9.4**	**$1.4**

The ISO's current GMC rate design went into effect in 2012. The design provides for three volumetric charges and five transaction fees. The design was updated in 2014; the amendment was approved by FERC December 18, 2014; and was effective January 1, 2015. The amendment changed the percentages of the System Operations and Congestion Revenue Rights ("CRR") service charges, the Transmission Ownership Rights ("TOR") charge, and the revenue requirement maximum. The three volumetric charges are as follows:

1. Market Services charge, which makes up 27% of the revenue requirement;
2. Systems Operations charge, which comprises 70% of the revenue requirement; and
3. CRR Services charge, which makes up 3% of the revenue requirement.

The Market Services charge applies to MWh and MW of awarded supply and demand in the ISO market. The Systems Operations charge applies to MWh of metered supply and demand in the ISO controlled grid. The CRR Services charge applies to MWh of congestion. The 2016 GMC charges are shown in Figure 4.

Figure 5: The ISO's 2016 Grid Management Charges

Charge Code	Charge/ Fee Name	Rate effective 1/1/16	Billing Units
4560	Market Services Charge	$ 0.0850	MWh
4561	System Operations Charge	$ 0.2979	MWh
4562	CRR Services Charge	$ 0.0049	MWh
4515	Bid Segment Fee	$ 0.0050	per bid segment
4512	Inter SC Trade Fee	$ 1.0000	per Inter SC Trade
4575	SCID Monthly Fee	$ 1,000	per month
4563	TOR Charge	$ 0.2400	minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	number of nominations and bids
Other fees included in miscellaneous revenue			
4564	EIM Market Services Charge	$ 0.0519	MWh
4564	EIM System Operations Charge	$ 0.1341	MWh
701	EIR Forecast Fee	$ 0.1000	MWh

The EIM administrative charge was split into two components and the rates listed above were in effect on November 4. 2015.
Scheduling Coordinators: The scheduling coordinator application fee is $5,000.
CRR participants: The CRR application fee is $1,000 for applicants who are not already scheduling coordinators.
2016 rates are as approved by the CAISO Board of Governors on December 18, 2015.

See rate calculations at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/GridManagementChargeBudgetProcesses.aspx
For Forecast Fee rate which was approved 2/9/03 see Settlement BPM - Main body document Attachment B at:
http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

For SB 350 study purposes, the impact analysis only evaluated the Market Services Charge, System Operations Charge, and CRR Service Charge, because the other fees provide minimal revenue. It is estimated that with regionalization of the ISO, GMC charges will decrease on a

$/MWh basis due to improved efficiencies in operating the system and markets along with the increased load of the larger regional footprint.

The estimated GMC for 2020 and 2030 is based on the projection of future ISO revenue requirements for three cases: (1) the ISO as currently defined; (2) ISO plus PacifiCorp, consistent with the analyzed 2020 footprint; and (3) the expanded regional ISO, consistent with the analyzed 2030 regional footprint.

Currently, the ISO can recover its annual revenue requirement up to a revenue cap approved by FERC. (As part of the rate design filings with FERC in 2012, the ISO requests a cap on its annual revenue requirement.) This cap allows the ISO to plan its annual budget without the need to file a tariff rate change with FERC to recover its costs as these costs change during that annual budget planning process. . The FERC approved an annual cap of $202 million, starting in 2012 with no sunset date on the annual revenue requirement cap. In lieu of the sunset date, the ISO will conduct a cost-of service study every three years. The justification for the $202 million cap is contained within the FERC filing.[6] Once the ISOs projected annual revenue requirement exceeds $202 million/year, the ISO must seek FERC approval in advance of the financial year to increase the subject cap. The projected future revenue requirement is based on this existing revenue requirement cap, not on projected future annual revenue requirements.

With the expansion of the ISO balancing authority area to incorporate PacifiCorp, the ISO estimated, for budget purposes, that an additional $5 million of costs would be incurred in 2020 to cover direct and indirect expenses associated with a CAISO-PacifiCorp footprint. This cost is associated with an additional 30 staff. The cost for existing technology and physical infrastructure that the ISO has in place already will not change. The added $5 million in staff expenses, plus an additional $5 million for contingencies, is projected to increase the ISO's annual revenue requirement cap to $212 million/year.

In other words, the annual cost estimate for the CAISO+PAC footprint is derived as follows:

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6 http://ferc.gov/whats-new/comm-meet/2014/121814/E-14.pdf

Current Cap	$202 million
ISO+PAC (added staff)	$ 5 million
Subtotal	$207 million
Contingency (2.5%)	$ 5 million
Total 2020	$212 million

Similar to what the ISO has done in the past, the transition to regionalism would be absorbed during the ramp up time with no material impact to the revenue requirement. In addition, because PacifiCorp would now be contributing to the GMC consistent with the rate design, versus the EIM fee, the GMC is expected to decrease by 18% to the ISO existing GMC rate payers because the revenue requirement is approximately the same but the rate base for payment of the GMC increases.

The current GMC and the estimated GMC for the CAISO+PAC footprint is based on the loads and billing determinants shown in Figure 5.

Figure 6: Loads and Billing Determinants Assumed in the Future Grid Management Charge Current Practice and CAISO+PAC

Region	GWH	2*GWH	Billing Determinants Based on 2*GWH Load (in thousands)	Market Services Billing Determinants Based on 115% of 2*GWH Load (in thousands)
CAISO	229,724	459,448	459.4	528
CAISO+PAC	298,233	596,466	596.5	686

The ISO estimates that the revenue requirement cap would increase by an additional $70 million/year if the ISO expanded to the larger Regional ISO footprint, consisting of the entire US WECC without the PMAs.[7] The increased cap is projected to cover costs for an estimated additional 160 employees and some physical infrastructure. The infrastructure investments include hardware but not a new building. With an additional 2.5% contingency, this yields an

[7] Since regional expansion is with respect to balancing authority areas, the ISO's analysis only subtracts the power market administrations that are balancing authority areas. Since Western Area Power Administration–Sierra Nevada Region is part of the Balancing Authority of Northern California ("BANC"), it is assumed that BANC would be part of the regional expansion.

increased revenue requirement cap of $282 million/year for ISO operations of the expanded regional footprint.

This estimate of the ISO annual revenue requirement cap for the analyzed expanded regional footprint is derived as follows:

Cap for CAISO+PAC	$212 million
Additional Staffing	$ 27 million
Additional Infrastructure	$ 36 million
Subtotal	$275 million
Contingency (2.5%)	$ 7 million
Total	$282 million

Despite the higher annual costs, the GMC would decrease because the load and billing determinants almost triple for the larger regional footprint, as shown in Figure 6.

Figure 7: Loads and Billing Determinants Assumed in the Future Grid Management Charge Expanded Regional ISO

Region	GWH	2*GWH	Billing Determinants Based on 2*GWH Load (in thousands)	Market Services Billing Determinants Based on 115% of 2*GWH Load (in thousands)
Expanded Regional ISO	654,068	1,308,136	1,308.1	1,504

The final GMC calculation and resulting level of the GMC charges for current CAISO operations, the CAISO+PAC regional ISO footprint, and the expanded regional ISO footprint are shown in Figure 7. As shown in the figure, the CAISO-PAC footprint would result in a 19% decrease of the GMC charge. When applied to California loads, that yields a California ratepayer saving of $39 million/year. The GMC reduction for the expanded regional footprint of 39%, yields annual California ratepayer savings of $103 million/year.

Entity	Forecast Load GWH	2*GWH [1]	Market Services Billing Determinant [2] (in thousands)	Revenue Cap (in millions)	Market Service [3]	System Operations [4]	Congestion Revenue Rights [5]	Total
ISO	229,724	459,448	528	$202	$0.1032	$0.3078	$0.0132	$0.42
ISO+PAC	298,777	597,544	687	$212	$0.0833	$0.2483	$0.0106	$0.34
R-ISO Exp.	654,068	1,308,136	1,504	$282	$0.0506	$0.1509	$0.0065	$0.21

Notes:

1/ GMC is charged to both supply and demand

2/ Billing determinant = 2*GWH * 115%

3/ Market Services component is 27% of GMC based on cost of service allocation and is charged to market transactions (MW and MWH). Market Services rate = Annual Revenue Requirement *27% / Billing Determinant

4/ System Operations component is 70% of GMC based on cost of service allocation and is charged to energy flows both supply and demand. System Operations rate = Annual Revenue Requirement * 70% / 2*GWH

5/ Congestion Revenue Rights component is 3% of GMC based on cost of service allocation and is charged to energy of congestion. Congestion Revenue Rights rate = Annual Revenue Requirement * 3% / 2*GWH

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